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 non-confidential 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,

(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit an original and six copies of this form to:

Office of the Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, NE.
Room 3110
Washington, DC 20426

Retain one copy of this report for your files.

(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
825 N. Capitol St., NE.
Room 946
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.)

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 a letter or report to the Chief Accountant at the address indicated at III (b).

III. What and Where to Submit (Continued)

(c) Continued

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 statement 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:

Legal Reference and Records Management Branch
Federal Energy Regulatory Commission
941 North Capitol Street, NE.
Room 3100 ED-12.1
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, 825 North Capitol Street NE., Washington, DC 20426 (Attention: 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.

GENERAL INSTRUCTIONS (Continued)

IV. For any page(s) that is not applicable to the respondent, either
   (a) Enter the words "Not Applicable" on the particular page(s), or
   (b) 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. Complete this report by means which result in a permanent record. Complete the original copy in permanent black ink or typewriter print, if practical. The copies, however, may be carbon copies or other similar means of reproduction provided the impressions are clear and readable.

VI. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" at the top of each page is applicable only to resubmissions (see VIII. below).

VII. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses. (   ).

VIII. When making revisions, resubmit only those pages that have been changed from the original submission. Submit the same number of copies as required for filing the form. Include with the resubmission the Identification and Attestation page, page 1. Mail dated resubmissions to:

Chief Accountant
Federal Energy Regulatory Commission
825 North Capitol Street, NE.
Room 946
Washington, DC 20426

IX. Provide a supplemental statement further explaining accounts or pages as necessary. Attach the supplemental statement (8 1/2 by 11 inch size) to the page being supplemented. Provide the appropriate identification information, including the title(s) of the page and the page number supplemented.

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

XI. 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.

XII. Respondents may submit computer printed schedules (reduced to 8 1/2 by 11) instead of the preprinted schedules if they are in substantially the same format.

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, 1994
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) 05/09/95

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 VP, Controller & Chief Info Officer	03 Signature Roger D. Sandeen	04 Date Signed (Mo, Da, Yr) 05/09/95
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.		

130022

Per D. Hard
M004
0/1

Name of Respondent * Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	This Report Is:	Date of Report	Year of Report
* Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 19*

LIST OF SCHEDULES (Electric Utility) (Continued)

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. 12-86	
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	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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, Controller and Chief Information Officer
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 1994 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	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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.

4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e., year and company title) may be listed in column(a) provided the fiscal years for both the 10-K report and this are compatible.

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.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
Northern States Power Company (Wisconsin)	Electric and gas utility	100.00	
* Chippewa and Flambeau Improvement Company	Owning and operating water storage reservoirs	75.86	
* Clearwater Investments, Inc.	Affordable housing	100.00	
* NSP Lands	Real estate holdings	100.00	
United Power and Land	Real estate holdings	100.00	
Cormorant Corporation	Former owner of interest in coal and lignite properties	100.00	
First Midwest Auto Park, Inc.	Parking Ramp	100.00	
Cenergy, Inc.	Natural gas marketing and energy services	100.00	
Viking Gas Transmission Company	Natural gas transmission	100.00	
Eloigne Company	Affordable housing	100.00	
* NEO Corporation	Landfill gas/cogeneration	100.00	
NRG Energy, Inc.	Non-regulated energy products and services	100.00	
* Golden Gate Energy I, Inc.	Cogeneration	100.00	
* Golden Gate Energy II, Inc.	Cogeneration	100.00	
* Graystone Corporation	Uranium Enrichment	100.00	
* Hanford Energy I, Inc.	Cogeneration	100.00	
* NRG Construction Services	Construction services	100.00	
* NRG Energy Center, Inc.	District heating and cooling system	100.00	
* NRG Energy Jackson Valley I, Inc.	Waste-fuel/cogeneration	100.00	
* NRG Energy Jackson Valley II, Inc.	Waste-fuel/cogeneration	100.00	
* NRG International, Inc.	International business	100.00	

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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.

4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e., year and company title) may be listed in column(a) provided the fiscal years for both the 10-K report and this are compatible.

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.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
* NRG Operating Services, Inc.	Energy project operating and maintenance services	100.00	
* NRG Sunnyside, Inc.	Waste-coal	100.00	
* Okeechobee Power I, Inc.	Independent power producer	100.00	
* Okeechobee Power II, Inc.	Independent power producer	100.00	
* Okeechobee Power III, Inc.	Independent power producer	100.00	
* Prairie Wind Energy, Inc.	Domestic business development	100.00	
* San Joaquin Valley Energy I, Inc.	Biomass waste-fuel/ cogeneration	100.00	
* San Joaquin Valley Energy IV, Inc.	Biomass waste-fuel/ cogeneration	100.00	
* Scoria Incorporated	Coal drying facility	100.00	
* Wolverine Energy I, Inc.	Cogeneration	100.00	
* Wolverine Energy II, Inc.	Cogeneration	100.00	

< P103 >

Chippewa and Flambeau Improvement Company

- Indirect control through the Wisconsin Company

< P103 >

Clearwater Investments, Inc.

- Indirect control through the Wisconsin Company

< P103 >

NSP Lands

- Indirect control through the Wisconsin Company

< P103 >

NEO Corporation

- Reorganized operations transferred from the company to NRG Energy, Inc. as of July 1, 1994

< P103 >

Golden Gate Energy I, Inc.

- Indirect control through NRG Energy, Inc.

< P103 >

Golden Gate Energy II, Inc.

- Indirect control through NRG Energy, Inc.

< P103 >

Graystone Corporation

- Indirect control through NRG Energy, Inc.

< P103 >

Hanford Energy I, Inc.

- Indirect control through NRG Energy, Inc.

< P103 >

NRG Construction Services

- Indirect control through NRG Energy, Inc.

< P103 >

NRG Energy Center, Inc.

- Indirect control through NRG Energy, Inc.

< P103 >

NRG Energy Jackson Valley I, Inc.

- Indirect control through NRG Energy, Inc.

< P103 >

NRG Energy Jackson Valley II, Inc.

- Indirect control through NRG Energy, Inc.

< P103 >

NRG International, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

NRG Operating Services, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

NRG Sunnyside, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

Okeechobee Power I, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

Okeechobee Power II, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

Okeechobee Power III, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

Prairie Wind Energy, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

San Joaquin Valley Energy I, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

San Joaquin Valley Energy IV, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

Scoria Incorporated

- Indirect control through NRG Energy, Inc.

< P103.1 >

Wolverine Energy I, Inc.

- Indirect control through NRG Energy, Inc.

< P103.1 >

Wolverine Energy II, Inc.

- Indirect control through NRG Energy, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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.

3. Utilities which are required to file the same data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substituted page(s) should be the same size as this page.

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	President & Chief Operating Officer	Edward M Theisen	
3	VP & Chief Financial Officer	Edward J McIntyre	
4	VP - Minnesota Electric	Vincent E Beacom	
5	VP & General Counsel	Gary R Johnson	
6	President, NSP Generation	Leon R Eliason	
7	President - NSP Electric	Loren L Taylor	
8	VP - Finance	Arland D Brusven	
9	VP - Human Resources	Cynthia L Lesher	
10	VP - Customer Services	Robert H Schulte	
11	VP - Controller & Chief Information Officer	Roger D Sandeen	
12	President, NSP Gas	Keith H Wietecki	
13	President, NSP Generation	Douglas D Anthony	
14	VP & Treasurer	Jackie A Currier	
15	VP - Nuclear Generation	Edward L Watzl	
16	VP - Public & Govt Affairs	Thomas A Micheletti	
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29	**Notes:**		
30			
31	< P104-2(c) >		
32	Retired 11/30/94 (Theisen)		
33			
34	< P104-4(c) >		
35	Retired 07/31/94 (Beacom)		
36	< P104-6(c) >		
37	Retired 09/30/94 (Eliason)		
38			
39	< P104-15(c) >		
40	Assumed position on 09/07/94 (Watzl)		
41			
42	< P104-16(c) >		
43	Assumed position on 11/01/94 (Micheletti)		
44			

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 an 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	Retired
Dale L. Haakenstad	Retired
James J. Howard, Chairman, President and CEO	414 Nicollet Mall Minneapolis, Minnesota 55401
Allen F. Jacobson	Retired
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	Retired
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	Retired
Edwin M. Theisen, Retired 11/30/94 as President and COO	Retired

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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 supplemental statement 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: 55,590,004 By proxy: 55,589,884	April 27, 1994 805 Hennepin Avenue Minneapolis, MN

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): December 31, 1994 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	69,872,144	66,922,144	* 825,000	* 2,125,000
5	TOTAL number of security holders	87,501	85,263	988	1,250
6	TOTAL votes of Security holders listed below	48,977,609	46,673,480	389,466	1,914,663
7	Cede & Co				
8	Box 20, Bowling Green Station				
9	New York, New York	37,223,640	35,055,692	353,961	1,813,987
10					
11	First Trust Co., Inc				
12	Trustee of NSP-ESOP				
13	W555 First National Bank Building				
14	St. Paul, MN	5,411,898	5,411,898		
15					
16	NSP Agent				
17	414 Nicollet Mall				
18	Minneapolis, MN	4,857,488	4,857,488		

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	Kray & Co.				
20	120 Lasalle Street				
21	Chicago, IL	1,113,437	1,066,222	29,352	17,863
22					
23	Philadep & Co				
24	1900 Market Street				
25	Philadelphia, PA	190,846	166,080	6,153	18,613
26					
27	West Publishing				
28	P O Box 64526				
29	St. Paul, MN	61,300	61,300		
30					
31	Virg & Co				
32	C/O First Interstate Bank				
33	P O Box 9800				
34	Calabasas, CA	36,700			36,700
35					
36	Personal Service Insurance				
37	P O Box 1226				
38	Columbus, OH	32,300	29,800		2,500
39					
40	General Conferance of Seventh Day				
41	Adventists Hospital Fund				
42	12501 Old Columbia Pike				
43	Silver Springs, MD	25,000	25,000		
44					
45	NECO LTD INT				
46	P O Box 1087				
47	La Crosse, WI	25,000			25,000
48					
49					
50	* See Note 6 of the Notes to the				
51	Financial Statements for discussion of				
52	stock options and other performance				
53	awards.				

< p106-4(d) >

Cumulative Preferred Stock $3.60 series.

< p106-4(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.

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 attached to this page.

Community	Date of Expiration	Community	Date of Expiration
City of Rockford-Elec	03-21-2013	City of Minneapolis-Elec	12-31-2014
City of Lakeville-Elec	08-01-2013	City of Branch-Gas	10-17-2018
City of Hartland-Elec	10-04-2013	City of St. Stephen-Gas	01-04-2019
City of Dundas-Elec	10-24-2013	City of Jenkins-Gas	03-13-2019
City of Dundas-Gas	10-24-2013	City of Lakeshore-Gas	03-27-2019
City of Mankato-Elec	04-10-2014	City of Manhattan Beach-Gas	03-31-2019
City of Nisswa-Gas	04-10-2014	City of Cross Lake-Gas	04-10-2019
City of North Mankato-Elec	04-17-2014	City of Pequot Lakes-Gas	04-17-2019
City of Gibbon-Elec	05-03-2014	City of East Gull Lake-Gas	04-27-2019
City of Green Isle-Elec	06-12-2014	City of Breezy Point-Gas	05-15-2019
City of Casselton-Gas	07-04-2014	City of Pleasant Lake-Gas	06-06-2019
City of Moorhead-Gas	07-31-2014	City of Fifty Lakes-Gas	06-13-2019
City of Brainerd-Gas	08-14-2014	City of Baxter-Gas	06-20-2019

IMPORTANT CHANGES DURING THE YEAR (Continued)

Item No. 2 - None

Item No. 3 - None

Item No. 4 - None

Item No. 5 - None

Item No. 6 - See pages 256-257 for detail of 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 1994. Also, see Notes 7 & 8 on 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. G, E002/S-92-1281.

Item No. 7 - None

Item No. 8 - Classification

Classification	1994 Annual Average Base Salary Increase
1) Union	0% of base payroll
2) Nonunion non-exempt clerical and technical	0% of base payroll
3) Exempt	0% of base payroll

Item No. 9 - See Note 2 on the Notes to the Financial Statements for discussion of regulatory proceedings completed during 1994 and pending as of year-end. Also, see Note 15 on the Notes to the Financial Statements for a discussion of major contracts, agreements, commitments, legal proceedings, and environmental issues relavant to 1994. 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.

On July 14, 1993, the Company filed a lawsuit in US District Court for the District of Minnesota. The suit was filed in the interest of the Company's ratepayers against Westinghouse Electric Corp. (Westinghouse), the manufacturer of the Prairie Island steam generators, because of problems with the steam generators susceptibility to corrosion. The Company seeks to recover the past and future costs of inspections, maintenance, modifications and repairs made to the Prairie Island steam generators and related systems as a result of Westinghouse defects. The defects are "serious" in that they have caused the Company to incur significant expenditures in order to ensure that Prairie Island is a safe and economically efficient generating station. Safety has not been, nor will be compromised in any way as a result of the defects because the plant has been and continues to be well-maintained. The amount recoverable from Westinghouse under this proceeding, if any, is not determinable at this time.

On June 20, 1994, the Company and 13 other major utilities filed a lawsuit against the Department of Energy (DOE) in an attempt to clarify the DOE's obligation to accept spent nuclear fuel beginning in 1998. The suit was filed in the U.S. Court of Appeals, Washington, D.C. The primary purpose of the lawsuit is to insure the company and its customers receive timely storage of used nuclear fuel.

Item No. 10 - None

Item No. 11 - None

Item No. 12 - Not applicable

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Deloitte & Touche LLP

400 One Financial Plaza
120 South Sixth Street
Minneapolis, Minnesota 55402-1844

Telephone: (612) 397-4000
Facsimile: (612) 397-4450

INDEPENDENT AUDITORS' REPORT

Northern States Power Company (Minnesota)
Minneapolis, Minnesota

We have audited the balance sheets of Northern States Power Company (Minnesota) (the Company) as of December 31, 1994 and 1993, the related statements of income for the years then ended, and the related statement of retained earnings and cash flows for the year ended December 31, 1994, included on pages 110 through 123.13 of the accompanying Federal Energy Regulatory Commission (FERC) 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 audit 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 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 $316,111,000 of deferred income tax assets as deferred debits rather than as a 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 $678,114,000, current assets by $128,227,000, other long-term assets would be decreased by $506,404,000, current liabilities would be increased by $223,915,000, and long-term debt and other long-term liabilities by $70,520,000 as of December 31, 1994. Furthermore, operating revenues would be increased by $203,744,000, operating expenses by $145,621,000, cash provided by operating activities by $67,724,000, cash used in investing activities by $91,944,000, cash provided by financing activities by $17,351,000, and other income and deductions would be

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decreased by $31,959,000 for the year ended December 31, 1994. 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.

In our opinion, except for the effects of not consolidating majority-owned subsidiaries and of classifying certain deferred income tax assets as deferred debits, as discussed in the preceding paragraph, the financial statements referred to above present fairly, in all material respects, the financial position of Northern States Power Company (Minnesota) as of December 31, 1994 and 1993, the results of its operations for the years ended December 31, 1994 and 1993, and its retained earnings and its cash flows for the year ended December 31, 1994, in conformity with generally accepted accounting principles. Also, in our opinion, the information presented in the financial statements referred to above is presented fairly, in all material respects, in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases.

As discussed in Note 3 to the financial statements, the Company changed its method of accounting for postretirement health care costs in 1993.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The additional information regarding utility operating income by utility departments on the statement of income is presented for purposes of additional analysis and is not a required part of the basic financial statements. This additional information is the responsibility of the Company's management. Such information has been subjected to the auditing procedures applied in our audits of the basic financial statements and, in our opinion, is fairly stated in all material respects when considered in relation to the basic financial statements taken as a whole.

Deloitte & Touche LLP

April 28, 1995

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	$5,790,729,277	$6,079,367,958
3	Construction Work in Progress (107)	200-201	188,244,939	139,766,828
4	TOTAL UTILITY PLANT (Enter Total of lines 2 and 3)		$5,978,974,216	$6,219,134,786
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	2,500,492,895	2,702,004,051
6	Net Utility Plant (Enter Total of line 4 Less 5)	-	$3,478,481,321	$3,517,130,735
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	749,077,634	797,097,251
8	(Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	202-203	673,668,821	718,689,709
9	Net Nuclear Fuel (Enter Total of lines 7 Less 8)	-	$75,408,813	$78,407,542
10	Net Utility Plant (Enter Total of lines 6 and 9)	-	$3,553,890,134	$3,595,538,277
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)	-		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	31,628,343	34,853,381
15	(Less) Accum. Prov. for Depr. and Amort. (122)	-	7,639,099	9,412,275
16	Investments in Associated Companies (123)	-		
17	Investment in Subsidiary Companies (123.1)	224-225	459,815,200	606,255,902
18	(For Cost of Account 123.1, See Footnote Page 224, Line 42)	-		
19	Noncurrent Portion of Allowances	228-229		
20	Other Investments (124)		18,009,040	18,196,136
21	Special Funds (125-128)	-	101,379,842	145,426,770
22	TOTAL Other Property and Investments (Total of lines 14—17,19—21)		$603,193,326	$795,319,914
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)	-	18,203,188	10,362,787
25	Special Deposits (132-134)	-		250,145
26	Working Fund (135)	-	283,720	293,834
27	Temporary Cash Investments (136)	-	2,797,324	749,397
28	Notes Receivable (141)		3,536,094	3,312,741
29	Customer Accounts Receivable (142)	-	186,670,897	186,519,472
30	Other Accounts Receivable (143)	-	37,845,168	44,080,326
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	3,274,939	3,298,134
32	Notes Receivable from Associated Companies (145)	-	23,966,967	41,809,419
33	Accounts Receivable from Assoc. Companies (146)	-	20,001,108	18,078,953
34	Fuel Stock (151)	227	17,331,390	29,334,284
35	Fuel Stock Expenses Undistributed (152)	227	1,333,939	1,731,374
36	Residuals (Elec) and Extracted Products (153)	227		
37	Plant Materials and Operating Supplies (154)	227	96,144,662	93,224,068
38	Merchandise (155)	227		
39	Other Materials and Supplies (156)	227	309,484	386,288
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)	-	421,539	203,753
44	Gas Stored Underground-Current (164.1)	-	12,028,387	11,618,416
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	-	5,106,008	4,472,053
46	Prepayments (165)	-	8,525,500	11,233,448
47	Advances for Gas (166-167)	-		
48	Interest and Dividends Receivable (171)	-		
49	Rents Receivable (172)	-	115,918	240,697
50	Accrued Utility Revenues (173)	-	94,065,423	82,241,826
51	Miscellaneous Current and Accrued Assets (174)		421,893	155,144
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		$525,833,670	$537,000,291

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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)	-	$8,129,987	$8,654,789
55	Extraordinary Property Losses (182.1)	230		
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
57	Other Regulatory Assets (182.3)	232	265,691,768	278,837,937
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)	-	1,520,117	1,910,139
61	Temporary Facilities (185)	-	15,320	(6,162)
62	Miscellaneous Deferred Debits (186)	233	4,201,540	66,381,229
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)	-	37,672,612	42,210,307
66	Accumulated Deferred Income Taxes (190)	234	317,649,436	316,110,958
67	Unrecovered Purchased Gas Costs (191)	-	5,234,817	11,694,201
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		$640,098,501	$725,776,302
69	TOTAL Assets and other Debits (Enter Total of lines 10,11,12, 22,52,and 68)		$5,323,015,631	$5,653,634,784

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	$167,198,943	$167,305,359
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	547,381,939	549,697,867
7	Other Paid-in Capital (208-211)	253	(3,351,793)	(3,351,793)
8	Installments Received on Capital Stock (212)	252	209,540	(1,284)
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	932,915,826	943,106,664
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	193,393,071	238,168,056
13	(Less) Reacquired Capital Stock (217)	250-251	10,887,336	2,990,217
14	TOTAL Proprietary Capital (Enter Total of Lines 2 thru 13)	-	$2,066,860,190	$2,131,934,652
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	919,900,000	1,012,800,000
17	(Less) Reacquired Bonds (222)	256-257		
18	Advances from Associated Companies (223)	256-257		
19	Other Long-Term Debt (224)	256-257	270,785,494	261,446,146
20	Unamortized Premium on Long-Term Debt (225)	-	365,614	136,936
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-	4,197,582	4,413,639
22	TOTAL Long-Term Debt (Enter Total of Lines 16 thru 21)	-	$1,186,853,526	$1,269,969,443
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases-Noncurrent (227)	-	26,118	0
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)	-	15,035,425	30,408,959
28	Accumulated Miscellaneous Operating Provisions (228.4)	-	40,345,500	39,701,880
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		$55,407,043	$70,110,839
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-	106,200,000	234,779,000
33	Accounts Payable (232)	-	202,209,064	228,860,677
34	Notes Payable to Associated Companies (233)	-		
35	Account Payable to Associated Companies (234)	-	5,736,854	8,029,994
36	Customer Deposits (235)	-	1,782,117	1,592,604
37	Taxes Accrued (236)	262-263	170,072,664	174,618,937
38	Interest Accrued (237)	-	18,763,109	22,515,164
39	Dividends Declared (238)	-	46,195,050	47,283,257
40	Matured Long-Term Debt (239)	-		
41	Matured Interests (240)	-		
42	Tax Collections Payable (241)	-	9,675,185	8,590,609
43	Miscellaneous Current and Accrued Liabilities (242)		21,248,292	13,433,718
44	Obligations Under Capital Leases-Current (243)		199,568	26,118
45	TOTAL Current and Accrued Liabilities(Enter Total of lines 32 thru 44)		$582,081,903	$739,730,078

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)		$1,699,089	$1,438,788
48	Accumulated Deferred Investment Tax Credits (255)	266-267	161,221,559	149,181,575
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	54,513,644	68,354,951
51	Other Regulatory Liabilities (254)	278	220,690,983	182,769,110
52	Unamortized Gain on Reacquired Debt (257)	269		
53	Accumulated Deferred Income Taxes (281-283)	272-277	993,687,694	1,040,145,348
54	TOTAL Deferred Credits (Enter Total of Lines 47 thru 53)		$1,431,812,969	$1,441,889,772
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)		$5,323,015,631	$5,653,634,784

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 page 122 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	$2,282,803,179	$2,207,389,413
3	Operating Expenses			
4	Operation Expenses (401)	320-323	1,318,608,681	1,275,556,521
5	Maintenance Expenses (402)	320-323	144,093,397	135,956,382
6	Depreciation Expense (403)	336-338	237,028,391	232,121,656
7	Amort. & Depl. of Utility Plant (404-405)	336-338	4,830,987	2,921,671
8	Amort. of Utility Plant Acq. Adj. (406)	336-338		
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)		84,813	220,362
12	(Less) Regulatory Credits (407.4)		92,930	
13	Taxes Other Than Income Taxes (408.1)	262-263	218,948,953	208,944,806
14	Income Taxes - Federal (409.1)	262-263	101,246,295	78,894,522
15	- Other (409.1)	262-263	31,856,022	22,480,714
16	Provision for Deferred Income Taxes (410.1)	234,272-277	84,817,245	107,962,704
17	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	234,272-277	99,378,228	96,972,718
18	Investment Tax Credit Adj. - Net (411.4)	266	(9,436,014)	(8,120,581)
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)		$2,032,607,612	$1,959,966,039
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117, line 25)		* $250,195,567	$247,423,374

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues receivec or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 122.

8. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the 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 page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
$1,951,540,446	$1,859,115,428	$330,610,266	$347,621,102	$652,467	$652,883	2
						3
1,060,877,532	1,003,222,959	257,731,149	272,333,562			4
136,827,005	127,428,617	7,266,392	8,527,765			5
220,908,472	217,074,160	16,119,919	15,047,496			6
4,387,719	2,726,630	443,268	195,041			7
						8
						9
						10
84,813	220,362					11
		92,930				12
198,169,739	188,321,631	20,779,214	20,623,175			13
93,063,367	73,017,985	8,182,928	5,876,537			14
29,281,355	20,806,216	2,574,667	1,674,498			15
78,756,774	95,325,937	6,060,471	12,636,767			16
93,814,283	89,872,511	5,563,945	7,100,207			17
(8,883,136)	(7,672,244)	(552,878)	(448,337)			18
						19
						20
						21
						22
$1,719,659,357	$1,630,599,742	$312,948,255	$329,366,297			23
$231,881,089	$228,515,686	$17,662,011	18,254,805	$652,467	$652,883	24

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 (c)	Previous Year (p)
1						
2						
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< P114-24(c) >

ITEM NO. 6

(a)	Accrued customer refunds account balance 12-31-93 (Account 254)	$421,765
	Refunds received from suppliers to be passed on to customer	38,551
	Interest accrued on accounts	32,278
	Accrued customer refunds account balance 12-31-94	492,594

Note: The amount passed on to respondent's customers through the operation of the purchased gas adjustment clauses in rates for 1994 was zero.

(b) See Note 2 of the Notes to the Financial Statements for discussion of known refund obligation which was recorded in account 242.

On January 31, 1994, an appeal of the MPUC's determination on the allowed return on equity was filed with the Minnesota Court of Appeals by the Minnesota Department of Public Service, the Office of the Minnesota Attorney General and the Minnesota Energy Consumers intervenor groups. The appeal concerned the method of calculating the rate of return on common equity for both the Minnesota electric and gas retail cases. The amount at issue was approximately $7 million in annual revenues for the Company. On August 2, 1994, the Court affirmed the final rate orders issued in January 1994 for these rate cases. This appeal process is now completed. As a result of this decision, no adjustments or changes are required to rates charged to customers or to revenues recorded by the Company.

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	—	$250,[illegible]95,567	$247,423,374
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		3,488,758	3,663,781
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,174,260	3,343,256
31	Revenues From Nonutility Operations (417)		17,265,411	41,995,529
32	(Less) Expenses of Nonutility Operations (417.1)		13,551,615	30,858,874
33	Nonoperating Rental Income (418)		(50,468)	(60,938)
34	Equity in Earnings of Subsidiary Companies (418.1)	119	70,453,119	39,836,437
35	Interest and Dividend Income (419)		10,253,818	7,499,293
36	Allowance for Other Funds Used During Construction (419.1)		3,863,034	6,634,528
37	Miscellaneous Nonoperating Income (421)		(1,309,643)	596,069
38	Gain on Disposition of Property (421.1)		68,849	454,439
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$87,307,003	$66,417,008
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		197,472	187,608
42	Miscellaneous Amortization (425)	340	14,832	
43	Miscellaneous Income Deductions (426.1-426.5)	340	12,572,491	6,022,581
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$12,784,795	$6,210,189
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	875,248	1,163,664
47	Income Taxes - Federal (409.2)	262-263	3,180,962	9,451,648
48	Income Taxes - Other (409.2)	262-263	(277,769)	2,084,236
49	Provision for Deferred Inc. Taxes (410.2)	234,272-277	785,707	(7,356,908)
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)	234,272-277	4,317,792	[illegible]78,498
51	Investment Tax Credit Adj. - Net (411.5)		(54,756)	([illegible]03,112)
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		$191,600	$4,661,030
54	Net Other Income and Deductions (Enter Total of lines 39, 44, 53)		$74,330,608	$55,545,789
55	Interest Charges			
56	Interest on Long-Term Debt (427)		71,976,068	85,826,326
57	Amort. of Debt Disc. and Expense (428)		1,404,090	1,100,523
58	Amortization of Loss on Reacquired Debt (428.1)		2,765,833	1,518,285
59	(Less) Amort. of Premium on Debt - Credit (429)		22,577	96,492
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340	12,631	9,174
62	Other Interest Expense (431)	340	12,266,687	7,931,210
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,351,547	5,059,841
64	Net Interest Charges (Enter Total of lines 56 thru 63)		$81,051,185	$91,229,185
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$243,474,990	$211,739,978
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)		$243,474,990	$211,739,978

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 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, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)	[redacted]	
1	Balance - Beginning of Year	[redacted]	$932,849,162
2	Changes (Identify by prescribed retained earnings accounts)	[redacted]	
3	Adjustments to Retained Earnings (Account 439)	[redacted]	
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:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Acc. 439) (Total of lines 10 thru 14)		
16	Balance Transferred from Income (Account 433 less Account 418.1)		173,021,871
17	Appropriations of Retained Earnings (Account 436)	[redacted]	
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)	[redacted]	
24	All Series		(12,364,002)
25			
26			
27			
28			
29	TOTAL Dividends Declared - Preferred Stock (Acct. 437) (Total of lines 24 thru 28)		(12,364,002)
30	Dividends Declared - Common Stock (Account 438)	[redacted]	
31			(175,292,631)
32			
33			
34			
35			
36	TOTAL Dividends Declared - Common Stock (Acct. 438) (Total of lines 31 thru 35)		($175,292,631)
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		24,825,600
38	Balance - End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36, and 37)		$943,040,000

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	66,664
47	TOTAL Appropriated Retained Earnings (Account 215, 215.1) (Enter total of lines 45 and 46)	$66,664
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Enter total of lines 38 and 47)	$943,106,664
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)	
49	Balance - Begining of Year (Debit or Credit)	193,393,071
50	Equity in Earnings for Year (Credit) (Account 418.1)	70,453,119
51	(Less) Dividends Received (Debit)	24,825,600
52	Other Changes (Explain)	* (852,534)
53	Balance - End of Year (Total of Lines 49 Thru 52)	$238,168,056

< P119-52(b) >

Transfer From/(TO) Appropriated Retained Earnings by Subsidiary

Northern States Power Company (NSP) (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	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 attached to page 122. Information about noncash investing and financing activities should be provided on page 122. Provide also on page 122 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 page 122 the amounts 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)	$243,474,990
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	250,592,707
5	Amortization of (Specify)	
6	Nuclear Fuel	45,552,620
7	Deferred Debits/Credits	9,156,255
8	Deferred Income Taxes (Net)	(18,093,068)
9	Investment Tax Credit Adjustment (Net)	(9,490,770)
10	Net (Increase) Decrease in Receivables	(21,372,842)
11	Net (Increase) Decrease in Inventory	(8,294,827)
12	Net (Increase) Decrease in Allowances Inventory	0
13	Net Increase (Decrease) in Payables and Accrued Expenses	24,753,144
14	Net (Increase) Decrease in Other Regulatory Assets	(18,155,079)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(39,334,234)
16	(Less) Allowance for Other Funds Used During Construction	3,863,034
17	(Less) Undistributed Earnings from Subsidiary Companies	45,627,519
18	Other: Decrease in Accrued Utility Revenues	11,823,597
19	Miscellaneous Changes in Working Capital	(11,774,058)
20	Changes in Other Assets and Liabilities	23,483,811
21		
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	$432,831,693
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (Including Land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(257,977,564)
27	Gross Additions to Nuclear Fuel	(48,019,617)
28	Gross Additions to Common Utility Plant	(29,230,692)
29	Gross Additions to Nonutility Plant	(3,392,116)
30	(Less) Allowance for Other Funds Used During Construction	3,863,034
31	Other:	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	($334,756,955)
35		
36	Acquisition of Other Noncurrent Assets (d) External Decommissioning Fund	(42,676,504)
37	Proceeds from Disposal of Noncurrent Assets (d)	0
38		0
39	Investments in and Advances to Assoc. and Subsidiary Companies	(114,775,171)
40	Contributions and Advances from Assoc. and Subsidiary Companies	0
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	12,600,035
43		
44	Purchase of Investment Securities (a)	0
45	Proceeds from Sales of Investment Securities (a)	0

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

STATEMENT OF CASH FLOWS (Continued)

4. Investi.. .ctivities
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on page 122.
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 page 122.

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 page 122 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	0
47	Collections on Loans	0
48		
49	Net (Increase) Decrease in Receivables	0
50	Net (Increase) Decrease in Inventory	0
51	Net (Increase) Decrease in Allowances Held for Speculation	0
52	Net Increase (Decrease) in Payables and Accrued Expenses	0
53	Other: Net Increase in Construction Payables	12,300,424
54	Miscellaneous Other Investing Activities	(187,096)
55		
56	Net Cash Provided by (Used in) Investing Activities	[redacted]
57	(Total of lines 34 thru 55)	($467,495,267)
58		[redacted]
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long - Term Debt (b)	346,999,380
62	Preferred Stock	0
63	Common Stock	1,368,461
64	Other:	
65		
66	Net Increase in Short - Term Debt (c)	128,579,000
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	$476,946,841
71		
72	Payments for Retirement of:	[redacted]
73	Long - term Debt (b)	(265,603,169)
74	Preferred Stock	0
75	Common Stock	0
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	
79		0
80	Dividends on Preferred Stock	(12,266,752)
81	Dividends on Common Stock	(174,301,674)
82	Net Cash provided by (Used in) Financing Activities	[redacted]
83	(Total of lines 70 thru 81)	$24,775,246
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	[redacted]
86	(Total of lines 22, 57, and 83)	($9,888,328)
87		[redacted]
88	Cash and Cash Equivalents at Beginning of Year	21,000,512
89		[redacted]
90	Cash and Cash Equivalents at End of Year	11,112,184

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 18[illegible], [illegible]mortized 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 attached hereto.

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.

Certain reclassifications have been made to 1993 financial statements to conform to the 1994 presentation. These reclassifications had no effect on net income or earnings per share.

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.

Revenues - Revenues are recognized based on services provided to customers each month. Because customer utility 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 customers, include cost-of-energy adjustment clauses, under which rates are adjusted to reflect changes in average costs of fuels, purchased power and gas purchased for resale.

Utility Plant and Retirements - Utility plant is stated at original cost. The Company's utility plant and construction expenditures consist of approximately 84% electric and 16% gas. The cost of additions to utility plant includes contracted work, direct labor and materials, 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 for construction, to qualified Construction Work in Progress (CWIP). The rates were 5.0% in 1994 and 7.4% in 1993. 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 an increase of approximately \$0.5 million and a decrease of approximately \$0.9 million for the 1994 and 1993 annual depreciation accruals, respectively. The remaining lives of the Company's nuclear facilities were submitted for review in 1994. The recovery period recommended for the Prairie Island plant was reduced because of the uncertainty regarding used nuclear fuel storage. (See Note 14.) The filing, as approved by the MPUC, increased depreciation by approximately \$9.7 million due to the change from previously approved property lives. However, because the annual accruals for projected future decommissioning expenses decreased, the net impact to the Company from 1994 capital recovery filings is a decrease of about \$800,000 in annual depreciation and decommissioning expenses, effective Jan. 1, 1994.

Every five years, the Company also must file an average service life filing for transmission, distribution and general properties. The most recent filing, as approved by the MPUC, increased 1993 depreciation by approximately \$4.7 million from 1992 levels. In 1994, the Company submitted to the MPUC a depreciation study for the general plant accounts requesting a change in the depreciation calculation method. While a straight-line method is still used, the approved method change affects the level of detail at which depreciation expense is calculated. The impact to 1994 depreciation accruals from the change was a decrease of approximately \$1.1 million. Depreciation provisions, as a percentage of the average balance of depreciable utility property in service, were 3.60 percent in 1994 and 3.49 percent in 1993.

Decommissioning - The Company records the cost 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 reclamation and removal, over the estimated operating lives of the Company's nuclear plants.

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 future fuel disposal and DOE facility decommissioning, as discussed in Note 14.

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. When a single estimate of the liability cannot be determined, the low end of the estimated range is recorded. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers 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 related to decommissioning and restoration of its power plants and substation sites as a removal cost of retirement through plant depreciation expense.

Income Taxes - The Company records income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109 - Accounting for Income Taxes. (Before 1993, the Company followed SFAS No. 96---Accounting for Income Taxes, resulting in substantially the same accounting as SFAS No. 109.) 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 in Note 9.

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

Inventories - Materials and Supplies Inventories are carried at average cost.

Derivative Financial Instruments - 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 Energy, Inc. (NRG) has entered into currency hedging transactions through the use of forward foreign currency exchange agreement. Gains and losses on these contracts offset the effect of foreign currency exchange rate fluctuations on the valuation of the investments underlying the hedges. NRG is not hedging currency translation adjustments related to operating results. A third derivative arrangement is the use of natural gas futures contracts by the Company's subsidiary, Cenergy, Inc. (Cenergy) 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 Cenergy's non-regulated operating expenses.

Use of Estimates - In recording transactions and balances resulting from business operations, the Company uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, environmental loss contingencies, 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. Also, the depreciable lives of certain plant assets are reviewed and, if appropriate, revised each year, as discussed previously. (See Notes 10 and 14 for more information on the effects of these changes in estimates.)

Short-Term Investments - The Company carries its Short-Term Investments at cost which approximates market. The Company considers investments in certain debt instruments (primarily commercial paper) with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

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.

Supplemental Cash Flow Disclosures - During 1994, the Company made cash payments of $73,151,784 for interest (net of amounts capitalized) and $150,649,581 for income taxes. Cash and cash equivalents consist of cash ($10,362,787 - Account 131) and temporary cash investments ($749,397 - Account 136).

2. RATE MATTERS

On Aug. 9, 1994, the Company applied to the North Dakota Public Service Commission (NDPSC) for an annual electric rate reduction of $3.6 million. The reduction reflects a correction in cost allocations to the North Dakota jurisdiction. The Company also requested authority to make refunds to customers to effectively implement the reduction as of June 1, 1994. On Nov. 9, 1994, the NDPSC approved the proposed rate reduction, the liability for which has been accrued as of Dec. 31, 1994. In January 1995, the NDPSC held a hearing on the possibility of retroactive refunds for the period Jan. 1, 1989, through June 1, 1994, but has not yet reached a decision. The ultimate outcome of this proceeding is not determinable at this time.

Other rate increases filed in Wisconsin and North Dakota that were effective in 1994 increased revenues by approximately $2.6 million.

3. ACCOUNTING CHANGES

Postemployment Benefits - Effective Jan. 1, 1994, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 112---Employers' Accounting for Postemployment Benefits. This standard required the accrual of certain postemployment costs, such as injury compensation and severance, that are payable in the future. Initially, the Company's pre-1994 injury compensation liability was deferred in a regulatory asset based on a preliminary decision to request amortization through rates over future periods. In October 1994, another Minnesota utility was ordered by the MPUC to defer its pre-1994 SFAS No. 112 liability and amortize it to match a three-year rate recovery period. Since the Company may not file a rate case within the deferral period approved by the MPUC, which ends in 1996, the Company's pre-1994 liability of approximately $9.4 million (8 cents per share) was expensed during 1994. Approximately $8.7 million ($5.1 million net of tax), or 8 cents per share, of this amount, representing the unamortized deferred costs was expensed in the fourth quarter of 1994.

Fair Value Accounting for Certain Investments - Effective Jan. 1, 1994, the Company adopted the provisions of SFAS No. 115---Accounting for Certain Investments in Debt and Equity Securities. This new standard resulted in an increase of approximately $1.4 million in decommissioning investments to present such investments at their market value at Dec. 31, 1994. This increase represents an unrealized gain on investments, which has been deferred as a regulatory liability. The Company anticipates offsetting such gains, when realized, against decommissioning costs in future ratemaking.

Accounting for Employee Stock Ownership Plans (ESOP) - Effective Jan. 1, 1994, the Company adopted the American Institute of Certified Public Accountants' Statement of Position (SOP) 93-6. This SOP changed the accounting for compensation expense associated with ESOP plans, and changed how ESOP shares were considered for earnings-per-share calculations. No additional compensation expense was recorded by the Company in 1994 due to the adoption of this SOP. The impact of the reduction in average common shares was immaterial to 1994 earnings per share (an increase in earnings per share of less than 1 cent).

Postretirement Benefits - As discussed in Note 10, the Company changed its accounting for postretirement medical and death benefits in 1993. Due to rate recovery of the expense increases, there was no material effect on net income in 1993 or 1994. Of the $17 million in 1993 cost increases over 1992 due to adoption of SFAS No. 106, about $4.5 million was capitalized, $12 million was deferred to be amortized over rate recovery periods in 1994-1996, and about $0.5 million was expensed, but essentially offset by rate increases. In 1994, administrative and general expenses increased by approximately $16 million due to the full recognition of accrued SFAS No. 106 costs, including amounts deferred from 1993.

4. 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
Wisconsin Company	U.S.A.	100%
NRG Energy, Inc.	U.S.A.	100%
Viking Gas Transmission Company	U.S.A.	100%
Cenergy, Inc.	U.S.A.	100%
United Power & Land	U.S.A.	100%
First Midwest Auto Park	U.S.A.	100%
Cormorant Corporation	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. Before 1994, such investments had been limited to immaterial domestic projects. The equity method of accounting is applied to such investments 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 through 1994 was approximately $180.2 million. Earnings from equity interests in these subsidiary investments were $35.9 million in 1994.

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 as of and for the year ended Dec. 31, 1994:

Financial Position (Millions of dollars)	
Current Assets	$ 695.4
Other Assets	2,542.8
Total Assets	$3,238.2
Current Liabilities	$ 294.3
Other Liabilities	2,039.4
Equity	904.5
Total Liabilities and Equity	$3,238.2

Results of Operations (Millions of dollars)	
Operating Revenues	$1,397.7
Operating Income	$176.6
Net Income	$150.8

5. CUMULATIVE PREFERRED STOCK

At Dec. 31, 1994 and 1993, 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, 1994, the annualized dividend rates were $5.82 for Series A and $5.97 for Series B.

At Dec. 31, 1994, the various preferred stock series were callable at prices per share ranging from $102.00 to $103.75, plus accrued dividends. In 1993, the Company redeemed all 350,000 shares of its $7.84 series Cumulative Preferred Stock at $103.12 per share.

6. COMMON STOCK AND INCENTIVE STOCK PLANS

The Company's common shares have a par value of $2.50 per share. At Dec. 31, 1994 and 1993, 160,000,000 shares were authorized and 66,922,144 and 66,879,577 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, 1994, 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 non-qualified stock options. The options currently granted may be exercised one year from the date of grant and are exercisable thereafter for up to nine years. The plan also allows certain employees to receive restricted stock and other performance awards. Performance awards are valued in dollars, but are paid in shares based on the market price at the time of payment. Transactions under the various incentive stock programs, which may result in the issuance of new shares, were as follows:

Stock Awards (Thousands of shares)	1994	1993
Outstanding Jan. 1	**537.1**	528.7
Options granted	**304.0**	196.9
Other stock awards	**.2**	9.5
Options and awards exercised	**(42.6)**	(174.3)
Options and awards forfeited	**(16.1)**	(22.2)
Other	**(.2)**	(1.5)
Outstanding at Dec. 31	**782.4**	537.1

Option price ranges:		
Unexercised at Dec. 31	**$33.25-$43.50**	$33.25-$43.50
Exercised during the year	**$33.25-$43.50**	$33.25-$40.94

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. The differences between shares used for primary and fully diluted earnings per share were not material.

7. SHORT-TERM BORROWINGS

The Company has approximately $299 million of commercial bank credit lines under commitment fee arrangements. These credit lines make short-term financing available in the form of bank loans and support for commercial paper sales. There were no such borrowings at Dec. 31, 1994 or Dec. 31, 1993. At Dec. 31, 1994 and 1993, the Company had $234.8 million and $106.2 million, respectively, in short-term commercial paper borrowings outstanding. The weighted average interest rate on all short-term borrowings as of Dec. 31, 1994 and Dec. 31, 1993, was 6.0 percent and 3.3 percent, respectively.

8. LONG-TERM DEBT

The annual sinking-fund requirements of the 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 $700 million. The Company may, and has, applied property additions in lieu of cash payments on all series, except the 9 1/8 percent Series due July 1, 2019, as permitted by its First Mortgage Indenture. Except for minor exclusions, all real and personal property is subject to the liens of the first mortgage indentures.

At December 31, 1994, the interest rates on the Company's long-term debt ranged from 5.41% to 9 3/8%.

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 5.9 percent, 4.1 percent and 4.1 percent, respectively, at Dec. 31, 1994. 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, 1994, 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 long-term debt are: 1995, $6,657,000; 1996, $11,960,000; 1997, $103,365,000; 1998, $3,520,000; and 1999, $203,700,000.

9. INCOME TAX EXPENSE

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate (35% in 1994 and 1993) to net income before income tax expense. The reasons for the difference are as follows (in thousands):

(Thousands of dollars)	1994	1993
Tax computed at statutory rate	$123,164	$111,819
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	19,016	16,807
Equity in subsidiary earnings	(24,659)	(13,943)
Tax credits recognized	(8,561)	(8,224)
Nontaxable allowance for funds used during construction (AFC)-equity included in book income	(1,352)	(2,322)
Net-of-tax AFC included in book depreciation	4,860	4,403
Use of the flow-through method for depreciation in prior years	4,171	6,530
Effect of tax rate changes for plant-related items	(5,289)	(4,222)
Dividends paid on common shares held by ESOP	(2,983)	(3,009)
Other - net	55	(97)
Total income tax expense	$108,422	$107,742
Effective federal and state income tax rate on earnings of the Company	38.5%	38.5%

Income taxes are comprised of the following expense (benefit) items:

	1994	1993
Included in utility operating expenses:		
Current federal tax expense	$100,047	$ 78,895
Current state tax expense	31,856	22,481
Deferred federal tax expense	(11,695)	8,481
Deferred state tax expense	(2,866)	2,509
Deferred investment tax credits	(8,236)	(8,121)
Total	109,106	104,245
Included in other income and expense:		
Current federal tax expense	2,510	9,452
Current state tax expense	663	2,084
Current federal tax credits	(270)	0
Deferred federal tax expense	(3,134)	(6,719)
Deferred state tax expense	(398)	(1,217)
Deferred investment tax credits	(55)	(103)
Total	(684)	3,497
Total income tax expense	$108,422	$107,742

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

	1994	1993
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 852,772	$ 828,249
Net SFAS 109 adjustments to deferred taxes (see below)	77,668	52,273
Tax benefit transfer leases	71,825	81,778
Regulatory assets and other	37,880	31,388
Total deferred tax liabilities included in deferred credits	$1,040,145	$ 993,688
Deferred tax assets:		
Differences between book and tax bases of property	$138,021	$126,419
Regulatory liabilities	72,862	93,160
Deferred investment tax credits	56,857	61,839
Deferred compensation, vacation and other accrued liabilities not currently deductible	41,427	29,182
Other	6,944	7,049
Total deferred tax assets included in deferred debits	$316,111	$317,649
Net deferred tax liability	$724,034	$676,039

The Omnibus Budget Reconciliation Act of 1993 (the Act) was signed into law on Aug. 10, 1993, and increased the federal corporate income tax rate from 34 percent to 35 percent retroactive to Jan. 1, 1993. Deferred tax liabilities were increased for the rate change by approximately $29.6 million. However, due to regulatory deferral of utility tax adjustments, earnings were reduced by immaterial adjustments to deferred tax liabilities related to non-regulated operations.

The adoption of SFAS 109 in 1993 and SFAS 96 in 1988 resulted in adjustments to deferred tax balances. Due to the effects of regulation, these adjustments were not recorded in income but were recorded as regulatory assets and regulatory liabilities. The SFAS 109 regulatory liabilities presented on page 278 represent the net amount expected to be reflected in future customer rates based on the collection in prior ratemaking of deferred income tax amounts in excess of the actual liabilities recorded by the Company. This excess is the net effect of the use of flow-through tax accounting in prior ratemaking and the impact of changes in statutory income tax rates in 1981, 1986-87 and 1993. The SFAS 109 regulatory assets presented on page 232.1 represent the gross-up of AFC that had previously been recorded in plant on a net-of-tax or after-tax basis.

10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFITS

Pension Benefits - The Company 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.

For regulatory purposes, the Company's pension expense is 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 are recorded as a regulatory liability on the balance sheet. Net periodic pension cost for the Company and its subsidiaries include the following components:

	Dec. 31, 1994		Dec. 31, 1993	
(Thousands of dollars)	Total Plan	Co. Portion	Total Plan	Co. Portion
Service cost-benefits earned during the period	27,536	23,265	$25,015	$21,343
Interest cost on projected benefit obligation	65,107	56,592	71,075	61,331
Actual return on assets	(12,668)	(10,904)	(152,019)	(131,242)
Net amortization and deferral	(82,114)	(71,741)	66,299	57,271
Net periodic pension cost determined under SFAS No. 87	(2,139)	(2,788)	10,370	8,703
Costs recognized due to actions of regulators	3,922	3,922	5,117	5,117
Net periodic pension cost recognized for ratemaking	1,783	1,134	$15,487	$13,820

The funded status of the plan as of Dec. 31 is as follows:

(Thousands of dollars)				
Actuarial present value of benefit obligation:				
Vested	$571,254	$495,788	$655,002	$564,647
Nonvested	120,420	104,711	139,346	119,001
Accumulated benefit obligation	$691,674	$600,499	$794,348	$683,648
Projected benefit obligation	$836,957	$727,188	$ 974,160	$841,591
Plan assets at fair value	1,165,584	1,017,586	1,244,650	1,073,982
Plan assets in excess of projected benefit obligation	(328,627)	(290,398)	(270,490)	(232,391)
Unrecognized prior service cost	(21,538)	(18,707)	(22,580)	(19,500)
Unrecognized net actuarial gain	370,289	325,620	315,049	271,441
Unrecognized net transitional asset	691	604	767	663
Net pension liability recorded	$20,815	$17,119	$22,746	$20,213

The weighted average discount rate used in determining the actuarial present value of the projected obligation was 8 percent in 1994 and 7 percent in 1993. The rate of increase in future compensation levels used in determining the actuarial present value of the projected obligation was 5 percent in 1994 and 1993. Changes made to assumptions for the 1993 valuation decreased 1994 pension costs (determined under SFAS No. 87) by approximately $3 million. Changes made to assumptions for the 1994 valuation are expected to increase 1995 pension costs (determined under SFAS No. 87) by approximately $1 million. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 87 was 8 percent for 1994 and 1993. Plan assets principally consist of common stock of public companies and U.S. government securities.

Postretirement Health Care - The Company 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.

Effective Jan. 1, 1993, the Company adopted the provisions of SFAS No. 106---Employers' Accounting for Postretirement Benefits Other Than Pensions. SFAS No. 106 requires the actuarially determined obligation for postretirement health care and death benefits to be fully accrued by the date employees attain full eligibility for such benefits, which is generally when they reach retirement age. This is a significant change from the Company's pre-1993 policy of recognizing benefit costs on a cash basis after retirement. In conjunction with the adoption of SFAS No. 106, 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. This obligation considered 1994 plan design changes not in effect in 1993, including Medicare integration, increased retiree cost sharing and managed indemnity measures.

Before 1993, the Company funded payments for retiree benefits internally. While the Company generally prefers to continue using internal funding of benefits paid and accrued, significant levels of external funding have been required by the Company's regulators, as discussed below, including the use of tax-advantaged trusts. Plan assets held in such trusts as of Dec. 31, 1994, consisted of investments in equity mutual funds and cash equivalents. The following table sets forth the health care plan's funded status in 1994 for the Company and its subsidiaries.

	Dec. 31, 1994		Dec. 31, 1993	
(Millions of dollars)	Total Plan	Co. Portion	Total Plan	Co. Portion
APBO:				
Retirees	$132.2	$111.3	$120.2	$103.4
Fully eligible plan participants	21.5	18.1	18.8	15.8
Other active plan participants	79.4	66.8	90.8	76.4
Total APBO	233.1	196.2	229.8	195.6
Plan assets	8.0	3.9	6.1	3.7
APBO in excess of plan assets	225.1	192.3	223.7	191.9
Unrecognized net actuarial loss	2.3	3.9	(1.3)	(1.4)
Unrecognized transition obligation	(194.0)	(166.2)	(204.8)	(175.5)
Postretirement benefit obligation included in deferred credits	$33.4	$30.0	$ 17.6	$ 15.0

The assumed health care cost trend rates used in measuring the APBO at Dec. 31, 1994 and 1993, respectively, were 11.0 and 14.1 percent for those under age 65, and 7.5 and 8.0 percent for those over age 65. 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 13 percent as of Dec. 31, 1994. Service and interest cost components of the net periodic postretirement cost would increase by approximately 16 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 8 percent for Dec. 31, 1994, 7 percent for Dec. 31, 1993, and 8 percent for Jan. 1, 1993, compounded annually. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 106 was 8 percent for 1994 and 1993. While the 1994 assumption changes had no effect on 1994 benefit costs, the effect of the changes in 1995 is expected to be a cost decrease of approximately $1.3 million. Similarly, the assumption changes made for the Dec. 31, 1993, calculations had no effect on 1993 benefit costs, but decreased 1994 costs by approximately $2 million.

The Company's net annual periodic postretirement benefit cost recorded for 1994 and 1993 consists of the following components:

(Millions of dollars)	1994	1993
Service cost-benefits earned during the year	$ 4.2	$ 3.8
Interest cost (on service cost and APBO)	13.6	14.9
Actual return on assets	(.1)	(.1)
Amortization of transition obligation	9.2	9.2
Net amortization and deferral	(.2)	.1
Net periodic postretirement health care cost under SFAS No. 106	26.7	27.9
Costs deferred due to actions of regulators	4.1	(12.1)
Net periodic postretirement health care cost recognized for ratemaking	$30.8	$15.8

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

ESOP - The Company 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 the Company realizes a tax savings on its income statement from dividends paid on certain shares held by the ESOP. Contributions to the ESOP in 1994 and 1993 which represent compensation expense, were $5,695,000 and $6,281,000, respectively. ESOP contributions have no material effect on the Company's earnings because the contributions (net of tax) are essentially offset by the tax savings provided by the dividends paid on ESOP shares. (See Note 9.) Leveraged shares held by the ESOP are allocated to participants when dividends on stock held by the plan are used to repay ESOP loans. Of the 5.4 million shares of the Company's stock that the Company's ESOP currently holds, an average of 111,845 uncommitted leveraged ESOP shares were excluded from earnings-per-share calculations in 1994. The fair value of the Company's leveraged ESOP shares approximated cost at Dec. 31, 1994.

401(k) - The Company has a contributory, defined contribution Retirement Savings Plan (the Plan), which complies with section 401(k) of the Internal Revenue Code and covers substantially all employees. Beginning in 1994, the Company matches specified amounts of employee contributions Plan. The Company's matching contributions were $2.1 million in 1994.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

	1994		1993	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents and short-term investments	$11,112	$11,112	$21,001	$21,001
Long-term decommissioning investments	$145,467	$145,467	$101,378	$110,130
Long-term debt	$1,269,969	$1,225,098	$1,186,854	$1,231,692

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 in external nuclear decommissioning funds are estimated based on quoted market prices for those or similar investments. As discussed in Note 3, the Company adopted in 1994 SFAS No. 115, which required certain debt and equity securities to be recorded at their market value. The Company began recording decommissioning fund investments at their market value at that time. 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 offered to the Company for debt of the same remaining maturities.

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, 1994
5 7/8% Series due Oct. 1, 1997	$100	Maturity	5.69%
5 1/2% Series due Feb. 1, 1999	$200	Maturity	6.68%

Market risks associated with these agreements result from short-term interest rate fluctuations. Credit risk related to non-performance of the counterparties is not deemed significant, but would result in the Company terminating the swap transaction and recognizing a gain or loss, depending on the fair market value of the swap. Such agreements are not reflected on the Company's balance sheets. The interest rate swaps serve to hedge the interest rate 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, 1994, the present value of the Company's additional obligation would have been $24.5 million, which is offset by a reduction in the present value of the related debt of $24.4 million below carrying value.

Subsidiary Hedge Instruments - NRG has entered into three forward foreign currency exchange contracts with a counterparty 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, denominated in Australian dollars and German deutsche marks (DM). NRG's forward foreign currency exchange contracts, in the notional amount of $93 million, hedge approximately $94 million of foreign currency denominated investments at Dec. 31, 1994. These forward foreign currency exchange contracts, and required compensating balances of $7 million are maintained at the subsidiary level. The contracts terminate in 2004 and require foreign currency interest payments by either party during each year of the contract. If the contracts had been terminated at Dec. 31, 1994, $4.3 million would have been payable by NRG for currency exchanges rate changes to date. Management believes NRG's exposure to credit risk due to non-performance by the counterparty to its forward exchange contracts is not significant, based on the investment grade rating of the counterparty.

Cenergy has entered into natural gas futures contracts in the notional amount of $16.1 million at Dec. 31, 1994. The 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 Cenergy's natural gas reserves. Cenergy's futures contracts hedge the sale of $16.6 million of natural gas. These futures contracts, and required margin balances of $3.4 million which were maintained on deposit with brokers at Dec. 31, 1994, were maintained at the subsidiary level. The counterparties to the futures contracts are the New York Mercantile Exchange and major gas pipeline operators. Management believes that the risk of non-performance by these counterparties is not significant. If the contracts had been terminated at Dec. 31, 1994, $1.7 million would have been payable by Cenergy for natural gas price fluctuations to date.

12. 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):

	1994	1993
Operating revenues:		
Electric	$186,922	$175,240
Gas	227	267
Operating expenses:		
Purchased and interchange power	47,605	46,632
Gas purchased for resale	50	56
Other operations	25,898	25,531

Gas Purchases - The Company's subsidiary, Viking Gas Transmission Company (Viking), transports gas purchased by the Company from various suppliers. The Company incurred the following transportation costs under various contracts with Viking, which extend through 2008:

	1994	1993
Gas Purchased from Viking:		
Company only	$744,000	$762,000
Jointly with Wisconsin subsidiary	991,000	424,000

13. 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, 1994 and 1993, was $585,783,000 and $584,822,000, respectively. The corresponding accumulated provisions for depreciation were $132,092,000 and $114,251,000.

14. 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 0.1 cent per kilowatt-hour sold to customers from nuclear generation. The cumulative amount of such assessments from the DOE to the Company through Dec. 31, 1994, is $218.5 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 DOE has stated in statute and by contract that a storage or permanent disposal facility would be ready to accept used nuclear fuel by 1998. Accordingly, the Company has been, with regulatory and legislative approval, providing its own temporary on-site storage facilities at its Monticello and Prairie Island plants, with a capacity sufficient for used fuel from the plants until at least that date. However, indications from the DOE are that a permanent federal facility will not be ready to accept used fuel from utilities until approximately 2010. Accordingly, the Company is investigating all of its alternatives for used fuel storage until the DOE facility is available. When on-site temporary storage at the Company's nuclear plants reaches approved capacity, the Company could seek interim storage at a contracted private facility. The Company received Minnesota legislative approval in 1994 for additional on-site storage facilities at its Prairie Island plant, provided the Company satisfies certain responsibilities. Seventeen dry cask containers, each of which can store approximately one-half year's used fuel, can 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 (MW) 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, certain resource commitments are not met, or the Minnesota Legislature revokes its approval. (See additional discussion of legislative commitments in Note 15.) 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 2002 and 2003 for Prairie Island Units 1 and 2, respectively, and 2008 for Monticello. Storage availability for operation beyond these dates is not assured at this time.

Fuel expense includes DOE fuel disposal assessments of $10.6 million and $8.7 million for 1994 and 1993, respectively. Disposal expenses reflect reductions of $0.7 million in 1994 and $2.6 million in 1993 due to a change in the DOE's basis of charging customers, retroactive to 1983. Nuclear fuel expenses in 1994 and 1993 also include about $5 million and $1 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 will be expensed on a monthly basis in the 12 months following each payment. The most recent installment paid in 1994 was $3.9 million; future installments are subject to inflation adjustments under DOE rules. The FERC has approved wholesale ratemaking recovery of these assessments as paid through the cost-of-energy adjustment clause. Since the Company's retail regulators currently conform to the FERC's cost-of-energy adjustment clause procedures, the Company also expects recovery of these DOE assessments in retail ratemaking as payments are made each year.

Plant Decommissioning - Decommissioning of all Company nuclear facilities is planned for the years 2010-2022, using the prompt dismantlement method. The Company is 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. The Financial Accounting Standards Board is reviewing the accounting and reporting guidelines for decommissioning cost accruals. Until such guidelines require a different presentation, the Company plans to continue reporting plant decommissioning obligations as accumulated depreciation. Consequently, the total decommissioning cost obligation and corresponding asset currently are not recorded in the Company's financial statements. In addition, the Company cannot predict whether new guidelines, if issued, would increase or decrease decommissioning expenses or if the income statement presentation of such expenses would 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. Under this approach, escalated future costs are discounted to current year dollars using 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 is currently 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 contributions and related earnings will be funded through internally generated funds and issuance of Company debt or stock. The assets held in trusts as of Dec. 31, 1994, primarily consisted of investments in tax-exempt municipal bonds, common stock of public companies and U.S. government securities.

The following table summarizes the funded status of the decommissioning obligation at Dec. 31, 1994:

(Millions of dollars)	
Estimated future decommissioning costs (undiscounted)	$1 838.1
Effect of discounting future payments	1 053.5
Present value of decommissioning obligation	784.6
External trust fund assets at fair value	145.5
Decommissioning obligation in excess of assets currently held in external trust	$639.1

Decommissioning expenses recognized include the following components:

(Millions of dollars)	1994	1993
Annual decommissioning cost accrual reported as depreciation expense:		
Externally funded	$33.2	$28.4
Internally funded (including interest costs)	1.1	14.5
Interest cost on externally funded decommissioning obligation	3.5	3.7
Earnings from external trust funds-net	(3.5)	(3.7)
Current year decommissioning accruals-net	$34.3	$42.9

At Dec. 31, 1994, the Company has recorded and recovered in rates cumulative decommissioning accruals of $340 million; $138 million has been deposited into external trust funds for such accruals. The Company believes future decommissioning cost accruals will continue to be recovered in customer rates. Decommissioning and interest accruals are included with the accumulated provision for depreciation on the balance sheet. Interest costs and trust earnings are reported in Other Income and Deductions on the income statement.

A revision to the Company's 1993 nuclear decommissioning study and nuclear plant depreciation capital recovery request was filed with the MPUC and approved in 1994. Although management expects to operate the Prairie Island units through the end of their licensed lives, the requested capital recovery would allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, 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, discussed previously. The updated nuclear decommissioning study supports a decrease in annual cost accruals for decommissioning as well as the shortened recovery period. The combined impact of the request as approved, including the shorter depreciation period and lower decommissioning costs, is a net decrease of about $800,000 in annual depreciation and decommissioning expenses. The revised cost levels approved by the MPUC were recorded in 1994.

15. 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 14. The additional resource commitments, which can be built, purchased or (in the case of biomass generation) converted, can be summarized as follows:

Power Type	Megawatts		Deadline
Wind	100*	(Additional)	12/31/96
Wind	225	(Cumulative)	12/31/98
Biomass	50	(Additional)	12/31/98
Wind	200	(Additional)	12/31/02
Biomass	75	(Additional)	12/31/02
Wind	400**	(Additional)	12/31/02

* In addition to 25 MW of wind generation currently installed.

** If required by least-cost planning and resource planning.

Other commitments include applying for, locating and licensing an alternative used fuel storage site, a low-income discount for electric customers, additional required conservation improvement expenditures and various study and reporting requirements to a newly formed legislative electric energy task force. The Company has implemented programs to begin meeting these legislative commitments.

Capital Commitments - The Company estimates utility capital expenditures, including acquisitions of nuclear fuel, will be $328.2 million in 1995 and $1.6 billion for 1995-1999. There also are contractual commitments for the disposal of used nuclear fuel. (See Note 14.)

The Company's Wisconsin subsidiary presently estimates its utility capital expenditures will be $55 million in 1995 and $286 million for 1995-1999. Capital spending for all non-regulated projects of the Company and its subsidiaries is estimated to be as much as $153 million in 1995 and $623 million for the five-year period 1995-1999.

NRG is contractually committed to additional equity investments in an existing German energy project. Such commitments are for approximately DM 36 million in 1995 and DM 35 million in 1996. The 1995 and 1996 commitments would be approximately $23 million each year, based on exchange rates in effect at Dec. 31, 1994.

Leases - Rentals under operating leases were approximately $21.1 million and $24.5 million for 1994 and 1993, respectively.

Fuel Contracts - The Company has long-term 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 1995 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 $600 million of coal, $35 million of nuclear fuel and $281 million of natural gas, 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. As a result of FERC Order 636, the Company has been very active in developing a mix of gas supply contracts designed to meet its needs for retail gas sales. The contracts are with several suppliers and for various periods of time. Because the Company has other sources of fuel available, and because suppliers are expected to continue to provide reliable fuel supplies, risk of loss from non-performance under these contracts is not considered significant. In addition, the Company'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	1995-2005	500
Seasonal Participation Power Purchase	1995-1996	250
Seasonal Peaking Power Purchase	1995-1996	200
Seasonal Diversity Exchanges:		
Summer exchanges from MH	1995-2014	150
	1997-2016	200
Winter exchanges to MH	1995-2014	150
	1996-2015	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 total estimated future annual capacity costs for all MH agreements range from approximately $66 million to $69 million. Negotiations are under way regarding the interpretation of specific contractual factors relating to the annual cost of the 500-megawatt participation agreement. These commitments, which represent about 21 percent of MH's output capability in 1995, account for approximately 13 percent of the Company's 1995 system capability. The risk of loss from non-performance 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 and MH jointly have made commitments to provide additional transmission capacity to accomplish the seasonal diversity exchanges and to provide 200 MW of transmission capacity for United Power Association. The Company's agreements with MH call for the addition of facilities that will allow the Company's existing 500-kilovolt line from Winnipeg to the Twin Cities to accommodate the additional levels of transactions. The first two phases of construction, which provide the majority of the benefits to the Company, were completed in 1994. The final phase, which primarily benefits MH, is expected to be completed in May 1995.

The Company has an agreement with Minnkota Power Cooperative (MPC) for the purchase of summer season capacity and energy. From 1995 through 2001, the Company will buy 150 MW of summer season capacity for $12.4 million annually. From 2002 through 2015, the Company will purchase 100 MW of capacity for $10.0 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 three seasonal (summer) purchase power agreements with MPC, Minnesota Power and Iowa-Illinois Gas and Electric Company for the purchase of 331 MW in 1995 and 388 MW in 1996, including reserves. The annual cost of this capacity will be approximately $4 million.

The Company has agreements with several non-regulated power producers to purchase electric capacity and associated energy. The total annual cost of current commitments for non-regulated installed capacity is approximately $20 million for 107 MW in 1995 and 119 MW in 1996. This annual cost will increase to approximately $37 million-$45 million for 1997-2018 and to approximately $25 million-$29 million for 2019-2027 due to a new power purchase agreement. Under this agreement, which was approved by the MPUC in February 1995, the Company will purchase an additional 245 to 262 MW of electric capacity and associated energy from 1997 through 2027.

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 $79.3 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 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 American Nuclear Insurers/Mutual Atomic Energy Liability Underwriters (ANI/MAELU) and $1.5 billion from Nuclear Electric Insurance Limited (NEIL). As of Jan. 1, 1995, insurance with ANI/MAELU will change to Nuclear Mutual Limited. The coverage amounts will remain unchanged.

NEIL provides insurance coverage for the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units and coverage for property losses in excess of $500 million occurring at nuclear stations. Premiums billed to the Company from NEIL are expensed as paid each year. All companies insured with NEIL are subject to retrospective premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that the Company would have no exposure in case of a single incident under the replacement power coverage and the property damage coverage. However, in each calendar year, the Company could be subject to maximum assessments of approximately $4.6 million (five times the amount of its annual premium) and $26.1 million (7.5 times the amount of its annual premium) if losses exceed accumulated reserve funds under the replacement power and property damage coverages, respectively.

Environmental Contingencies - Other noncurrent liabilities and deferred credits include an accrual of $49 million at Dec. 31, 1994, for estimated costs associated with environmental remediation. Approximately $40 million of the liability relates to a DOE assessment for decommissioning of a federal uranium enrichment facility, as discussed in Note 14. 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 14 for further discussion.)

The Company has not developed any specific site restoration and exit plans for its fossil fuel plants, hydroelectric plants or substation sites because the Company intends to operate at these sites indefinitely. If such plans were developed in the future, the Company would intend to treat restoration and exit costs as a removal cost of retirement in utility plant and include them in depreciation accruals. An estimated removal cost (based on historical experience) is currently included in depreciation expense.

The Company has met or exceeded state and federal removal and disposal requirements for polychlorinated biphenyls (PCB) equipment. The Company has removed nearly all PCB capacitors, transformers and equipment from its distribution system and power plants. Minimal costs are expected to be incurred for future removal and disposal of PCB equipment. PCB-contaminated mineral oil is detoxified and reused or burned for energy recovery at a permitted facility, with minimal cost to the Company. Other than described below, any potential future cleanup or remediation costs for past PCB disposal is unknown at this time.

As of April 28, 1995, the Environmental Protection Agency (EPA) or state environmental agencies have designated the Company as a "potentially responsible party" (PRP) for 11 waste disposal sites to which the Company allegedly sent hazardous materials. The Company's share of the costs associated with these 11 sites is approximately $2.5 million. Of this amount, about $1.4 million has already been paid in connection with six of the 11 sites for which the Company has settled with the EPA and other PRPs. For the remaining five 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 $1 million for future costs for all five sites. While it is not feasible to determine the outcome of these matters, amounts accrued represent the best current estimate of the Company's future liability for the remediation costs of these sites. 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 remedial costs paid to date. Management believes costs incurred in connection with the sites, which are not recovered from insurance carriers or other parties, might be allowed recovery in future ratemaking. Until the Company is identified as a PRP, it is not possible for the Company to predict the timing or amount of any costs associated with cleanup sites other than those discussed above.

The Company also is continuing to investigate 15 properties, either presently or previously owned by the Company, which were at one time sites of gas manufacturing, gas storage plants or gas pipelines. The purpose of this investigation is to determine if waste materials are present, if such materials constitute 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. Of the 15 gas sites under investigation, the Company already has remediated one site. The Company currently estimates its liability for the other six active sites to be approximately $8.4 million, with payment expected over the next 11 years. As for the other eight inactive sites, no liability has been recorded for remediation since at this time the sites require only monitoring. While it is not feasible to determine the precise outcome of all of these matters, the accruals recorded represent the current best estimate of the costs of any required cleanup or remedial actions at these former gas operating sites. Management also believes that costs incurred in connection with the sites, which are not recovered from insurance carriers or other parties, might 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 the next general gas rate case.

The Clean Air Act, including the Amendments of 1990 (the Clean Air Act), imposes stringent limits on emissions of sulfur dioxide and nitrogen oxides by electric generating plants. These limits will be phased in beginning in 1995. The majority of the rules implementing this complex legislation have been finalized. No additional capital expenditures are anticipated to comply with the sulfur dioxide emission limits of the Clean Air Act. The Company has expended significant amounts over the years to reduce sulfur dioxide emissions at its plants. Based on revisions to the sulfur dioxide portion of the program, the Company's emission allowance allocations for the years 1995-1999 were dramatically reduced. 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 only beginning to implement some provisions of the Clean Air Act, its overall financial impact is unknown at this time. Capital expenditures will be required for opacity compliance commencing in 1995 at certain facilities, and such costs are considered in the capital expenditure commitments disclosed previously. The Company plans to seek recovery of these expenditures 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 required 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. The Company estimates its future asbestos removal costs will approximate $43 million. Most of these costs will not need to be incurred until current operating facilities are demolished and will be included in the costs of removal for the facilities.

Environmental liabilities are subject to considerable uncertainties that affect the Company'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 July 1993, a natural gas explosion occurred on the Company's distribution system in St. Paul, Minn. Total damages 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. While 12 lawsuits have been filed, including one proposed class action, the litigation following this incident is in a preliminary stage and the ultimate costs to the Company are unknown at this time.

Environmental liabilities are subject to considerable uncertainties that affect the Company'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.

16. SUBSEQUENT EVENT - PROPOSED MERGER (UNAUDITED)

On April 28, 1995, the Company and Wisconsin Energy Corporation (WEC) entered into an agreement and plan of merger ("merger"). As a result, a registered public utility holding company, which will be known as Primergy Corporation (Primergy), will be the parent of both the Company's and WEC's operating subsidiaries. Each outstanding share of common stock of the Company will be converted into 1.626 shares of common stock of Primergy, and each outstanding share of common stock of WEC will be converted into one share of common stock of Primergy. The merger is intended to be tax-free for federal and state income tax purposes, and to be accounted for as a "pooling of interests". The merger is subject to various conditions, including approval of the stockholders of the Company and WEC, and the approval of various regulatory agencies. The Company anticipates that the completion of the regulatory review and approval process will take approximately 12-18 months and, accordingly, the companies do not anticipate completing this merger until late in 1996.

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	$6,071,752,577	$5,429,360,622
4	Property Under Capital Leases	26,118	26,118
5	Plant Purchased or Sold	0	
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	TOTAL (Enter Total of lines 3 thru 7)	$6,071,778,695	$5,429,386,740
9	Leased to Others	2,599,944	2,599,944
10	Held for Future Use	4,752,173	791,120
11	Construction Work in Progress	139,766,828	102,636,278
12	Acquisition Adjustments	237,146	237,146
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	$6,219,134,786	$5,535,651,228
14	Accum. Prov. for Depr., Amort., & Depl.	2,702,004,051	2,441,390,943
15	Net Utility Plant (Enter Total of line 13 less 14)	$3,517,130,735	$3,094,260,285
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation	2,674,952,724	2,437,741,674
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	25,534,034	2,131,976
22	TOTAL In Service (Enter Total of lines 18 thru 21)	$2,700,486,758	$2,439,873,650
23	Leased to Others		
24	Depreciation	1,502,461	1,502,461
25	Amortization and Depletion		
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)	$1,502,461	$1,502,461
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.	14,832	14,832
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31 and 32)	$2,702,004,051	$2,441,390,943

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/0[illegible]/95	Year of Report Dec. 31, 1994

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
$469,860,467				$172,531,488	3
					4
					5
					6
					7
$469,860,467				$172,531,488	8
					9
				3,961,053	10
5,792,126				31,338,424	11
					12
$475,652,593			0	$207,830,965	13
170,065,249				90,547,859	14
$305,587,344			0	$117,283,106	15
[redacted]					16
					17
170,065,249				67,145,801	18
	[redacted]				19
					20
				23,402,058	21
$170,065,249				$90,547,859	22
[redacted]					23
					24
					25
					26
[redacted]					27
					28
					29
					30
	[redacted]				31
					32
$170,065,249				$90,547,859	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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	2,995,065	11,245,525
3	Nuclear Materials	11,948,985	35,471,223
4	Allowance for Funds Used during Construction	202,238	783,053
5	(Other Overhead Construction Costs)	211,336	519,816
6	SUBTOTAL (Enter Total of lines 2 thru 5)	$15,357,624	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	0	50,872,500
9	In Reactor (120.3)	204,192,786	51,252,905
10	SUBTOTAL (Enter Total of lines 8 thru 9)	$204,192,786	
11	Spent Nuclear Fuel (120.4)	529,527,224	43,521,557
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)	673,668,821	
14	TOTAL Nuclear Fuel Stock (Enter Total lines 6, 10, 11, and 12 less line 13)	$75,408,813	
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		

< P202-15(b) >

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

< P202-16(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	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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

Changes During the Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	* 12,570,054	1,670,536	2
	* 36,881,389	10,538,819	3
	* 874,022	111,269	4
	* 547,035	184,117	5
		$12,504,741	6
			7
	* 50,872,500	0	8
	* 43,521,557	211,924,134	9
		$211,924,134	10
	* 380,405	572,668,376	11
			12
(45,552,620)	* 531,732	718,689,709	13
		$78,407,542	14
		0	15
			16
			17
			18
			19
			20
			21
			22

< P203-2(e) >
Classified to Account 120.2

< P203-3(e) >
Classified to Account 120.2

< P203-4(e) >
Classified to Account 120.2

< P203-5(e) >
Classified to Account 120.2

< P203-8(e) >
Transferred to Account 120.3

< P203-9(e) >
Transferred to Account 120.4

< P203-11(e) >
Reinserted into the reactor

< P203-13(e) >
Transferred to Account 321

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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. Attach supplemental statement showing 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	1,012,103	1,915,977
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$1,012,103	$1,915,977
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,158,020	629,407
9	(311) Structures and Improvements	281,240,473	4,320,985
10	(312) Boiler Plant Equipment	906,538,318	9,201,646
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	222,844,861	894,617
13	(315) Accessory Electric Equipment	141,236,049	109,716
14	(316) Misc. Power Plant Equipment	58,314,193	693,583
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	$1,618,331,914	$15,849,954
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	1,145,110	
18	(321) Structures and Improvements	278,939,701	12,942,308
19	(322) Reactor Plant Equipment	572,527,210	5,967,579
20	(323) Turbo generator Units	137,949,880	358,457
21	(324) Accessory Electric Equipment	190,111,401	10,453,375
22	(325) Misc. Power Plant Equipment	131,736,529	3,387,673
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	$1,312,409,831	$33,109,392
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	2,712,823	12,000
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)	$6,338,889	$12,000
33	D. Other Production Plant		
34	(340) Land and Land Rights	2,181,215	667,603
35	(341) Structures and Improvements	2,376,324	1,354,867
36	(342) Fuel Holders, Products, and Accessories	3,365,968	948,849
37	(343) Prime Movers		
38	(344) Generators	60,837,904	62,998,043
39	(345) Accessory Electric Equipment	3,793,255	3,267,510

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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
			2,928,080	(303)	4
			$2,928,080		5
[redacted]					6
					7
45,555			8,741,872	(310)	8
20,341		2,722,637	288,263,754	(311)	9
1,583,417	4,958	(2,824,413)	911,337,092	(312)	10
			0	(313)	11
814,436		(229,730)	222,695,312	(314)	12
16,800	(6,056)	348,837	141,671,746	(315)	13
192,544	45,567	155,088	59,015,887	(316)	14
$2,673,093	$44,469	$172,419	$1,631,725,663		15
[redacted]					16
			1,145,110	(320)	17
899,409			290,982,600	(321)	18
5,232,709	26,636	(1,930)	573,286,786	(322)	19
770,500			137,537,837	(323)	20
47,500			200,517,276	(324)	21
448,055		(319,501)	134,356,646	(325)	22
$7,398,173	$26,636	($321,431)	$1,337,826,255		23
[redacted]					24
			1,698,851	(330)	25
			442,146	(331)	26
			2,724,823	(332)	27
			1,140,299	(333)	28
			302,701	(334)	29
			42,069	(335)	30
			0	(336)	31
			$6,350,889		32
[redacted]					33
459			2,848,359	(340)	34
			3,731,191	(341)	35
			4,314,817	(342)	36
			0	(343)	37
70,000			123,765,947	(344)	38
35,000			7,025,765	(345)	39

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	$439,003	$32,778
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	$72,993,669	$69,269,650
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	$3,010,074,303	$118,240,996
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	36,274,930	356,843
45	(352) Structures and Improvements	8,550,821	190,665
46	(353) Station Equipment	232,920,277	36,923,304
47	(354) Towers and Fixtures	92,661,161	53,633
48	(355) Poles and Fixtures	93,158,917	5,026,900
49	(356) Overhead Conductors and Devices	115,797,918	3,739,052
50	(357) Underground Conduit	4,784,351	
51	(358) Underground Conductors and Devices	4,320,123	29,129
52	(359) Roads and Trails		
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	$588,468,498	$46,319,526
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	8,189,281	171,750
56	(361) Structures and Improvements	18,588,245	1,615,950
57	(362) Station Equipment	215,175,570	12,532,535
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	141,048,321	5,622,437
60	(365) Overhead Conductors and Devices	164,730,815	8,424,620
61	(366) Underground Conduit	75,913,602	2,820,134
62	(367) Underground Conductors and Devices	349,396,628	26,116,618
63	(368) Line Transfomers	218,597,632	8,239,731
64	(369) Services	125,065,243	8,390,736
65	(370) Meters	85,153,228	5,746,274
66	(371) Installations on Customer Premises	12,095,481	5,605,570
67	(372) Leased Property on Customer Premises	178,509	
68	(373) Street Lighting and Signal Systems	21,539,962	1,043,369
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	$1,435,672,517	$86,329,724
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	4,755,039	
72	(390) Structures and Improvements	42,446,309	1,179,448
73	(391) Office Furniture and Equipment	9,351,774	3,343,969
74	(392) Transportation Equipment	35,641,177	
75	(393) Stores Equipment	1,965,995	11,080
76	(394) Tools, Shop and Garage Equipment	18,023,729	2,165,926
77	(395) Laboratory Equipment	6,281,521	236,767
78	(396) Power Operated Equipment	5,045,331	
79	(397) Communication Equipment	35,870,691	1,885,976
80	(398) Miscellaneous Equipment	411,238	51,835
81	SUBTOTAL (Enter Total of lines 71 thru 80)	$159,792,804	$8,875,001
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	$159,792,804	$8,875,001
84	TOTAL (Accounts 101 and 106) (lines 5,15,23,32,41,53,69,83)	$5,195,020,225	$261,681,224
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)	$5,195,020,225	$261,681,224

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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.
			$471,781	(346)	40
$105,459			$142,157,860		41
$10,176,725	$71,105	($149,012)	$3,118,060,667		42
[redacted]					43
460,419	(2,281)		36,169,073	(350)	44
		(620)	8,740,866	(352)	45
710,093	2,544	(697,050)	268,438,982	(353)	46
70,270	6,017	(267,500)	92,383,041	(354)	47
459,245	65	169,113	97,895,750	(355)	48
411,414	2,081	(80,828)	119,046,809	(356)	49
			4,784,351	(357)	50
		11,679	4,360,931	(358)	51
			0	(359)	52
$2,111,441	$8,426	($865,206)	$631,819,803		53
[redacted]					54
21,968			8,339,063	(360)	55
59,748	23,744	298,809	20,467,000	(361)	56
1,870,353	1,531	354,370	226,193,653	(362)	57
			0	(363)	58
735,766		5,349	145,940,341	(364)	59
1,906,308		8,584	171,257,711	(365)	60
207,963		22,887	78,548,660	(366)	61
2,349,743		31,569	373,195,072	(367)	62
1,926,640	221,886	9,674	225,142,283	(368)	63
337,498		(43,434)	133,075,047	(369)	64
3,530,739	293,756		87,662,519	(370)	65
	(52,131)		17,648,920	(371)	66
			178,509	(372)	67
165,798			22,417,533	(373)	68
$13,112,524	$488,786	$687,808	$1,510,066,311		69
[redacted]					70
2,834			4,752,205	(389)	71
27,353		(76,053)	43,522,351	(390)	72
5,849			12,689,894	(391)	73
2,085,447		197,341	33,753,071	(392)	74
11,753			1,965,322	(393)	75
14,796		1,440	20,176,299	(394)	76
102,384		93,249	6,509,153	(395)	77
134,175		2,833	4,913,989	(396)	78
16,263			37,740,404	(397)	79
			463,073	(398)	80
$2,400,854		$218,810	$166,485,761		81
				(399)	82
$2,400,854		$218,810	$166,485,761		83
$27,801,544	$568,317	($107,600)	$5,429,360,622		84
[redacted]				(102)	85
					86
				(103)	87
$27,801,544	$568,317	($107,600)	$5,429,360,622		88

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 an 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	$2,599,944
2		115 KV Transmission Line #5509			
3		and a portion of a Transmission			
4		Substation			
5					
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43					
44					
45					
46					
47	TOTAL				$2,599,944

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:	[redacted]		
22	Distribution Substation Structure & Improvements			$184,874
23	Underground Conduit			265,500
24	Transmission Lines			21,602
25				
26				
27				
28				
29				
30				
31				
32				
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34				
35				
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39				
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41				
42				
43				
44				
45				
46				
47	TOTAL	[redacted]		$791,120

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	Angus Anson - 2 105 Mw Units	3,370,464
3	BDS - Generator Stator Coils	2,192,602
4	BDS - Id Fan Rotor	132,481
5	BDS - Turbine Blades	397,318
6	BLL - Dike	109,159
7	HB - Railroad Tracks	119,235
8	Lake Benton - Wind Generation	211,808
9	King - Coal Ash Disposal Pit	740,182
10	Red Wing - Lime Injection Storage	177,915
11	MNGP - Batteries	189,119
12	MNGP - Control Room Recorder	190,829
13	MNGP - Control Rod Drive	142,246
14	MNGP - EFT Design Modification	670,365
15	MNGP - Electrical Pressure Regulator	236,842
16	MNGP - MELLLA Installation	118,186
17	MNGP - MSIV Modifications	3,239,114
18	MNGP - Low Pressure Turbines	2,056,891
19	MNGP - Condensate Pump Motor	152,415
20	MNGP - Underground Storage Tank	151,780
21	MNGP - Biocide Residual Monitor	117,342
22	MNV - CEMS System	427,933
23	Pathfinder - Natural Gas Pipeline	460,919
24	PI - Spent Fuel Storage Alternate Site	208,954
25	PI - Battery Charger	102,695
26	PI - Spent Fuel Storage Facility	502,330
27	PI - Leading Edge Flow Measurement System	316,495
28	PI - Vari-Drive On Charging Pumps	199,477
29	PI - Simulator Core & Rcs Model	146,630
30	PI - Spent Fuel Cask Procurement	6,599,943
31	Red Wing - Reverse Osmosis Unit	135,622
32	RIV - Boiler Bottom Ash Hopper	184,517
33	RIV - Dust Collector Ductwork	121,457
34	RIV - Crusher Bldg Washdown	111,631
35	RIV - Track Upgrade	137,458
36	SH - Wet ESP Project	1,552,564
37	SH - Pond #3	124,463
38	OH - Landfill Cell #2	150,773
39	WEF - Fuel Controllers	100,321
40	Lake Benton - Wind Generation	1,674,328
41	Small Production Projects	1,924,314
42		
43	TOTAL	$29,899,117

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	TRANSMISSION PLANT	
2	West Faribault Sub - 115Kv OCB	144,822
3	Terminal Sub - Transformer Capacity Addition	4,078,579
4	Sheyenne Sub - Increase Capacity	3,705,616
5	Running Sub - Static Var Compensation	1,830,515
6	Roseau Sub - Shunt Capacitors	2,475,937
7	Moranville Sub - Install Breakers	654,469
8	Ln 0705 - Relocate For MNDOT	261,969
9	Red Rock Sub - Black Start	250,258
10	Prairie Sub - Static Var Compensation	5,494,464
11	Parker Lake Sub - Add Capacity	217,323
12	Ln 5702 - Manitoba-Minnesota Upgrade (MMTU)	388,088
13	Loon Lake Sub - Capacitor Bank	194,244
14	Kohlman Lake Sub - Ring Bus	272,005
15	King Sub - Black Start	230,363
16	Forbes Sub - Static Var Compensation	238,596
17	Chisago Sub - Black Start	139,585
18	Byron Sub - Black Start	125,013
19	Adams Sub - Black Start	187,366
20	King Sub - Power Transformer	190,655
21	Ln 0871 - Rebuild 1.6 Miles Of Line	580,512
22	West Gate Sub - Replace 115Kv Structures	177,709
23	Ln 0734 - Transformer Termination (Rahr Line)	252,192
24	West Gate Sub - Transformer	1,156,040
25	Ln 0802 - Rebuild Line	143,629
26	Small Transmission Projects	2,963,227
27		
28	DISTRIBUTION PLANT	
29	Medicine Lake Sub - MEL Relay Changes	119,091
30	Airport Sub - Relay Changes	108,139
31	Bloomington Sub - Breaker	784,138
32	Wilson Sub - Relay Changes	103,440
33	Twin Lakes Sub - Cap/Pin Replacement	160,155
34	Line Transformers	3,070,445
35	Hassan Sub - Increase Capacity	1,534,371
36	Salida Crossing Sub - LPI Recycling Facility	123,833
37	Aldrich Sub - Breaker	1,808,408
38	Elliot Park Sub - Breaker	1,636,593
39	Long Lake Sub - Increase Capacity	171,275
40	Wabasha Vault - Service To Children's Museum	113,902
41	Federal Reserve Vault - Install New Vault	143,877
42	North Star Steel Sub - Transformer	655,292
43	TOTAL	$66,765,252

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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	Ramsey Sub - New Feeder	$212,436
2	Reconstruct Sandrock Tunnels	126,954
3	Saver's Switches For Residential Load Control	460,302
4	Terminal Sub - Black Start	160,766
5	Terminal Sub - Transformer	122,186
6	Winona Sub - Increase Capacity	553,858
7	Small Distribution Projects	21,159,510
8		
9	GENERAL PLANT	
10	PI - Communication Network Equipment	229,771
11	Chestnut Service Center - Renovation Project	504,336
12	General Office - Interchange Transaction Scheduler	211,722
13	General Office - SCC SCADA/AGC/PCM System	2,921,340
14	General Office - SCC EMS Aplications	257,796
15	Chestnut Service Center - Metro West LAN System	107,685
16	General Office - Outage System	162,731
17	Ren Square - Production Costing System	628,612
18	GIS Project	2,534,547
19	Small General Plant Projects	1,851,087
20		
21	GENERAL OFFICE PROJECTS	
22	Various Construction Projects (PAS Interim Accounts)	658,634
23	Real Estate Taxes For Construction Work In Progress	3,387,489
24	Various Construction Projects - Payments Withheld	675,277
25	Undistributed Construction Overheads	(1,076,013)
26		
27	RESEARCH, DEVELOPMENT AND DEMONSTRATION	
28	RD&D Projects	0
29		
30		
31		
32		
33		
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42		
43	TOTAL	$102,636,278

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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	$2,821,924
2	Engineering and Supervision - Prorate	13,544,057
3	Engineering and Supervision - Direct	2,099,431
4	Engineering and Supervision - Outside	4,076,848
5	Allowance for Funds Used During Construction	4,850,823
6		
7		
8		
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45		
46	TOTAL	$27,393,083

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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.A)

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 $202,387		
(2)	Short-Term Interest			s 4.51%
(3)	Long-Term Debt	D $1,151,180	37.82%	d 6.87%
(4)	Preferred Stock	P $240,000	7.88%	p 6.13%
(5)	Common Equity	C $1,652,766	54.30%	c 11.47%
(6)	Total Capitalization	$3,043,946	100%	
(7)	Average Construction Work in Progress Balance	W $227,001		

2. Gross Rate for Borrowed Funds $s\left(\frac{S}{W}\right) + d\left(\frac{D}{D+P+C}\right)\left(1 - \frac{S}{W}\right)$ 4.30%

3. Rate for Other Funds $\left[1 - \frac{S}{W}\right]\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$ 0.73%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 4.29%

b. Rate for Other Funds - 0.67%

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 have 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 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, of give general advice and assistance on 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 constuction is charged to capital projects when the period of constuction 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 constuction was 5.0%, effective January 1, 1994 through December 31, 1994.

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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	$2,240,475,214	$2,239,039,386		$1,435,828
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	217,752,609	217,752,609		
4	(413) Exp. of Elec. Plt.Leas.to Others	66,633			66,633
5	Transportation Expenses—Clearing	2,769,629	2,769,629		
6	Other Clearing Accounts	3,275,790	3,275,790		
7	Other Accounts (Specify):				
8					
9	Total Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	$223,864,661	$223,798,028		$66,633
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	(27,285,085)	* (27,285,085)		0
12	Cost of Removal	(5,587,182)	(5,587,182)		0
13	Salvage (Credit)	7,137,474	7,137,474		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	($25,734,793)	($25,734,793)		0
15	Other Debit or Cr.Items (Describe):				
16	Adjustments (credit)	639,053	* 639,053		
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	$2,439,244,135	$2,437,741,674		$1,502,461
	Section B. Balances at End of Year According to Functional Classifications				
18	Steam Production	706,479,976	706,479,976		
19	Nuclear Production	875,978,192	875,978,192		
20	Hydraulic Production-Conventional	3,851,320	3,851,320		
21	Hydraulic Production-Pumped Storage				
22	Other Production	60,900,416	60,900,416		
23	Transmission	214,883,753	214,217,468		666,285
24	Distribution	505,298,290	504,462,114		836,176
25	General	71,852,188	71,852,188		
26	TOTAL (Enter Total of lines 18 thru 25)	$2,439,244,135	$2,437,741,674		$1,502,461

< P219-11(c) >

Electric Plant in Service Book Cost of Plant retired is $14,776 more than Depreciable Plant Retired pages 204-207, column D (excluding land) because occasionally plant retirements do not get cleared to reserve in the current month.

< P219-16(c) >

Includes retirement adjustments of $-565,145; net transfer between utilities of $-532,112; net changes in Electric Retirement Work In Progress of $458,203.

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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 an 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 Services:			
2				0
3	12-58 Underground conduit and Manholes Acq Fr T.C.R.T.	71,925		71,925
4	12-58 Formerly PT Fargo Diesel Plant Site	200,954		200,954
5	11-87 Portion of 69KV Line No. 0708	90,210		90,210
6	12-89 Portion of 69KV Line No. 0734	33,614		33,614
7				
8				
9				
10				
11	Other Nonutility Property:			
12				
13	05-76 Easements-Line 0854 (Parkers Lake-Crow River)	49,889	(200)	49,689
14	1968-1972 Easements-Line 0864 (Coon Rapids-St. Cloud)	44,490		44,490
15	07-80 Easements-Line 0985 (Sherburne County-Parkers Lk)	60,533		60,533
16	05-76 Easements-Line 5702 (Moorhead-Twin Cities)	63,053		63,053
17	11-82 Wescott Propane Plant-House & Garage	82,000		82,000
18	06-83 Easements-Line 0871 (Moore Lake-West Coon Rapids)	90,193	(75)	90,118
19	10-83 Cedar Lake Substation Site	173,629		173,629
20	1984-1986 Sherburne County-House & Out Buildings	324,000		324,000
21	1985 500KV Line No. 5703-House, Garage Etc	139,770	(139,770)	0
22	1992 Shady Oak Substation	644,982	(4,528)	640,454
23	1985-1990 Refuse Derived Fuel	28,948,730	1,006,632	29,955,362
24	1993 CNG Compressor-Reinforced Thermo Products, Inc	25,755	14,777	40,532
25	1993 Liberty Paper Steam Line	25,252	2,099,616	2,124,868
26	1992-1993 Renaissance Square Ultra Power Monitor	29,154	45,872	75,026
27	1994 69KV Line 0734-Poles & Conductor		171,579	171,579
28	1991 Grand Forks Boiler Plant	121,421		121,421
29				0
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	302,283	31,135	333,418
46	TOTAL	$31,628,3[illegible]3	$3,225,038	$34,853,381

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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	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			204,078,370
6	SUBTOTAL			300,829,316
7				
8				
9	UNITED POWER AND LAND COMPANY			
10	Common Stock-par $100 per share			14,020,000
11	Undistributed subsidiary			
12	earnings since acquisition			2,148,108
13	SUBTOTAL			16,168,108
14				
15				
16	CORMORANT CORPORATION			
17	Common Stock-par $10 per share			1,275,000
18	Undistributed subsidiary			
19	earnings since acquisition			(798,971)
20	SUBTOTAL			476,029
21				
22				
23	FIRST MIDWEST AUTO PARK, INC.			
24	Common Stock-par $1.00 per share			3,330,605
25	Undistributed subsidiary			
26	earnings since acquisition			1,219,757
27	SUBTOTAL			4,550,362
28				
29				
30	NRG ENERGY, INC.			
31	Notes Receivable	12/31/93	12/01/06	9,466,697
32	Common Stock-par $100 per share			112,128,881
33	Undistributed subsidiary			
34	earnings since acquisition			(13,816,945)
35	SUBTOTAL			107,778,633
36				
37	ELOIGNE COMPANY			
38	Common Stock-no par value			8,250,000
39	Undistributed subsidiary			
40	earnings since acquisition			(146,656)
41	SUBTOTAL			8,103,344
42	TOTAL Cost of Account 123.1 $		TOTAL	$[illegible]7,905,792

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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
					2
			96,750,946		3
					4
38,545,081		*	216,945,317		5
38,545,081	0		313,696,263	0	6
					7
					8
					9
		*	4,020,000		10
					11
640,178			2,788,286		12
640,178	0		6,808,286	0	13
					14
					15
					16
			1,275,000		17
					18
180,665			(618,306)		19
180,665	0		656,694	0	20
					21
					22
					23
		*	730,570		24
					25
219,100			1,438,857		26
219,100	0		2,169,427	0	27
					28
					29
					20
		*	8,957,278		31
		*	216,028,881		32
					33
28,939,258		*	15,106,379		34
28,939,258	0		240,092,538	0	35
					36
					37
		*	16,250,000		38
					39
1,174,581			1,027,925		40
1,174,581	0		17,277,925	0	41
$69,698,863			$580,701,133		42

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			13,000,000
3	Undistributed Subsidiary			
4	earnings since acquisition			853,332
5	SUBTOTAL			13,853,332
6				
7				
8	NEO CORPORATION			
9	Common Stock-no par value			200,000
10	Undistributed subsidiary			
11	earnings since acquisition			(15,934)
12	SUBTOTAL			184,066
13				
14				
15	CENERGY, INC.			
16	Common Stock-no par value			8,000,000
17	Undistributed subsidiary			
18	earnings since acquisition			(127,990)
19	SUBTOTAL			7,872,010
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	TOTAL Cost of Account 123.1 $ 359,130,567		TOTAL	$459,815,200

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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
734,095		1,587,427		4
734,095	0	14,662,598	0	5
				6
				7
				8
		*		9
				10
		*		11
0	0	0	0	12
				13
				14
				15
		* 11,000,000		16
				17
20,161		(107,829)		18
20,161	0	10,892,171	0	19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
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				35
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				37
				38
				39
				40
				41
$70,453,119	0	$606,255,902	0	42

< P224-3(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 Wis	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	Jul. 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

< P225-5(g) >

In 1994, Undistributed subsidiary earnings for Northern States Power Company (Wis) was reduced by $852,534 due to subsidiary appropriation of retained earnings.

Dividends of $24,825,600 were paid to the Company by Northern States Power Company (Wis) in 1994.

< P225-10(g) >

Repurchase of stock by United Power and Land Company totaling $10,000,000.

< P225-24(g) >

Repurchase of stock by First Midwest Auto Park totaling $2,600,035.

< P225-31(g) >

Refuse-derived fuel operations were transfered to NRG Energy, Inc., a wholly owned subsidiary of the Company, in exchange for a Note Receivable in 1993. $509,419 was transferred to Notes Receivable-Current Portion, FERC account 141 in 1994.

< P225-32(g) >

Purchased stock in NRG Energy, Inc totaling $103,000,000.

Transfer of NEO Corporation to NRG Energy, Inc; Common Stock transfer $900,000 and undistributed subsidiary earnings as of December 31, 1993 of $(15,934).

< P225-34(g) >

Purchased stock in NRG Energy, Inc totaling $103,000,000.

Transfer of NEO Corporation to NRG Energy, Inc; Common Stock transfer $900,000 and undistributed subsidiary earnings as of December 31, 1993 of $(15,934).

< P225-38(g) >

Purchased stock in Eloigne Company totaling $8,000,000.

< P225.1-2(g) >

Final purchase adjustment in Viking Gas totaling $75,171.

< P225.1-9(g) >

Purchased stock in NEO Corporation totaling $700,000.

Transfer of NEO Corporation to NRG Energy, Inc; Common Stock transfer $900,000 and undistributed subsidiary earnings as of December 31, 1993 of $(15,934).

< P225.1-11(g) >

Purchased stock in NEO Corporation totaling $700,000.

Transfer of NEO Corporation to NRG Energy, Inc; Common Stock transfer $900,000 and undistributed subsidiary earnings as of December 31, 1993 of $(15,934).

< P225.1-16(g) >

Purchase stock in Cenergy Inc totaling $3,000,000.

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 (on a supplemental page) 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)	$17,331,390	$29,334,284	
2	Fuel Stock Expenses Undistributed (Account 152)	1,333,939	1,731,374	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	40,592,277	38,134,237	All Utilities
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	41,445,885	41,756,803	All Utilities
8	Transmission Plant (Estimated)	620,083	1,098,352	All Utilities
9	Distribution Plant (Estimated)	12,043,555	10,422,126	All Utilities
10	Assigned to - Other	1,442,862	1,812,550	All Utilities
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	$96,144,662	$93,224,068	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)	309,484	386,288	
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	421,539	203,753	
16	Liquified Natural Gas Stored			
17	(Account 164)	17,134,395	16,090,469	
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$132,675,409	$140,970,236	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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)	1995 No. (d)	1995 Amt. (e)
01	Balance-Beginning of Year	0	0	0	0
02					
03	Acquired During Year:				
04	Issued (Less Withheld Allow.)	0	0	* 4,158.00	0
05	Returned by EPA	0	0	0	0
06					
07	Purchases/Transfers:				
08	None	0	0	0	0
09					
10					
11					
12					
13					
14					
15	Total	* 0	0	0	0
16					
17	Relinquished During Year:				
18	Charges to Account 509	0	0	0	0
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	None	0	0	0	0
23					
24					
25					
26					
27					
28	Total	* 0	0	0	0
29	Balance-End of Year	0	0	4,158.00	0
30					
31	Sales:				
32	Net Sales Proceeds (Assoc. Co.)	0	0	0	0
33	Net Sales Proceeds (Other)	0	0	0	0
34	Gains	0	0	0	0
35	Losses	0	0	0	0
	Allowances Withheld (Account 158.2)				
36	Balance-Beginning of Year	1,150.00	0	1,930.00	0
37	Add: Withheld by EPA	1,794.00	0	1,794.00	0
38	Deduct: Returned by EPA		0	0	0
39	Cost of Sales	1,014.00	0		0
40	Balance-End of Year	* 1,930.00	0	3,724.00	0
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		20,541		
44	Net Sales Proceeds (Other)		* 199,249		
45	Gains				
46	Losses				

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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.

1996		1997		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
4,158.00	0	8,316.00	0	12,474.00	0	24,948.00	0	01
4,158.00	0	4,158.00	0	87,323.00	0	99,797.00	0	02 03 04
0	0	0	0	0	0	0	0	05
0	0	0	0	0	0	0	0	06 07 08
								09
								10
								11
								12
								13
								14
0	0	0	0	0	0	0	0	15
0	0	0	0	0	0	0	0	16 17 18
								19
								20
0	0	0	0	0	0	0	0	21 22
								23
								24
								25
								26
								27
0	0	0	0	0	0	0	0	28
8,316.00	0	12,474.00	0	99,797.00	0	124,745.00	0	29
0	0	0	0	0	0	0	0	30 31 32
0	0	0	0	0	0	0	0	33
0	0	0	0	0	0	0	0	34
0	0	0	0	0	0	0	0	35
3,724.00	0	5,630.00	0	7,536.00	0	19,970.00	0	36
1,906.00	0	1,906.00	0	5,607.00	0	13,007.00	0	37
0	0	0	0	0	0	0	0	38
	0		0		0	1,014.00	0	39
5,630.00	0	7,536.00	0	13,143.00	0	31,963.00	0	40
						0	20,541	41 42 43
						0	199,249	44
								45
								46

< P228-4(d)) >

All allowances are valued at $0 from EPA.

< P228-15(b)) >

NSP has made no sales or purchases other than those sold by EPA auction, and has no plans to do so.

< P228-28(b)) >

NSP has made no sales or purchases other than those sold by EPA auction, and has no plans to do so.

< P228-40(b)) >

No allowances were withheld from substitution units.

< P228-44(c)) >

NSP distributed $11,470 from 1994 EPA Aution to Southern Minnesota Municipal Power Agency for their ownership share of Sherburne County 3.

Pending the filing and approval of the Company's proposed ratemaking treatment by regulators, all gains from sale of allowances have been deferred as a regulatory liability.

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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:				
3					
4	Electric Operations	135,997,298	107	85,581	64,577,378
5			131	98,805	
6			142	3,592	
7			143	74,705	
8			154	307,719	
9			163	62,468	
10			165	523	
11			182.3	499,846	
12			184.1	1,715,243	
13			184.2	50,416,833	
14			186	2,211,069	
15			232	1,737,981	
16			241	(1,442)	
17			403	55,073	
18			415	10,276	
19			419	6,774	
20			419.1	2,442,743	
21			432	1,344,352	
22			456	3,698,191	
23			588	25	
24			908	45,002,004	
25			910	128	
26					
27	Gas Operations	4,253,409	131	5,626	1,703,390
28			184.1	2,319	
29			184.2	98,954	
30			232	569,492	
31			419.1	83,679	
32			495	324,057	
33			908	1,756,558	
34			921	4,655	
35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	$140,250,707	[redacted]	$112,617,829	$66,280,768

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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		Balance at End of Year (e)
			Account Charged (c)	Amount (d)	
1	UNRECOVERED ENVIRONMENTAL COSTS:				
2					
3	DOE Decommissioning & Decontamination Assessment	7,356,293	518	5,098,194	47,776,099
4					
5	Pathfinder Plant Decommissioning Costs Incurred-Net	109,267	143	62,595	0
6			406	89,210	
7			426.5	7,480	
8					
9	Gas Site Remediation Costs Incurred	2,011,626	186	447	2,003,113
10			232	8,066	
11					
12	Environmental Cleanup - Waste Disposal Sites	0	253	1,133,581	0
13					
14					
15	TAX RELATED COST DEFERRALS:				
16					
17	Net-of-Tax AFUDC Adjustments-FASB 109	0	283	10,836,000	146,777,000
18					
19	IRS and State Interest Deferrals	15,748	143	299,883	1,166,299
20			236	108,447	
21			431	759,500	
22					
23	Sales and Use Tax Deferrals	655	143	30,194	78,908
24					
25					
26	EMPLOYEE BENEFIT COST DEFERRALS:				
27					
28	Accrued Costs-FASB 106	620,000	926	4,125,701	9,211,750
29					
30	Deferred Compensation Plan Costs - FASB 87	0	253	1,339,000	0
31					
32	SOUTH DAKOTA RATEMAKING DIFFERENCES:	864,000	421	1,281,000	5,544,000
33			426.5	285,000	
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	$151,228,296		$138,082,127	$278,837,937

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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	0	54,394,956	*	1,344,235	53,050,721
4	(including interest)					
5						
6	IPP Power Contract Billing	0	2,277,672		0	2,277,672
7	Adjustments					
8						
9	Energy Loan & Other Programs	0	9,761,792	*	5,351,942	4,409,850
10	Administered for State Agencies					
11						
12	Damage Claims Against other	3,482,137	10,655,296	*	8,476,159	5,661,274
13	Parties					
14						
15	Other	(188,820)	217,161		0	28,341
16						
17						
18	* DEFERRED CHARGES:					
19						
20	Prepaid Regulatory Fees	0	408,188		0	408,188
21						
22	Securities Registration Costs	258,975	119,548	*	266,896	111,627
23						
24						
25	DEBITS NOT ELSEWHERE PROVIDED					
26	FOR:					
27						
28	Items for which Final	15,406	109,145	*	37,126	87,425
29	Disposition is Uncertain					
30						0
31						0
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	633,842	[redacted]			346,131
48	DEFERRED REGULATORY COMM. EXPENSES (See pages 350-351)					
49	TOTAL	$4,201,540	[redacted]			$66,381,229

P233-3(d) >

ccounts charged include:	131	$342,606
	142	1,629
	236	1,000,000
	TOTAL	$1,344,235

P233-9(d) >

ccounts charged include:	131	$930
	142	1,163,457
	182.3	7,281
	184.1	7,700
	184.2	513,928
	232	3,554,161
	910	104,485
	TOTAL	$5,351,942

P233-12(d) >

ccounts charged include:	107	$190,593
	108	146,249
	131	2,359,552
	143	59,098
	154	22,969
	184	32
	184.1	6,521
	232	2,571,691
	242	700,000
	512	1,275,574
	925	1,143,880
	TOTAL	$8,476,159

P233-18(a) >

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

P233-22(d) >

Accounts charged include:	181	$266,329
	232	567
	TOTAL	$266,896

< P233-28(d) >

Accounts charged include:	108	$1,270
	142	19,711
	154	2,934
	232	13,211
	TOTAL	$37,126

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	[redacted]	
2		* $296,730,573	$284,633,166
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	$296,730,573	$284,633,166
9	Gas	[redacted]	
10		* 16,338,029	15,018,659
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	$16,338,029	$15,018,659
17	Other Non Operating	* 4,580,834	16,459,133
18	TOTAL (Acct 190)(Total of lines 8,16 and 17)	$317,649,436	$316,110,958

NOTES

< P234-2(b)) >

Electric (Other)	Bal at Beg of Year	Bal at End of Year
Accrued Vacation Paid	5,561,882	6,466,888
Ad Valorem Tax Coal	62,113	158,274
Avoided Tax Interest	9,450,106	12,310,592
Bad Debts	1,093,791	1,185,214
Coal Mine Reclamation Reserve	1,118,924	1,294,688
Compensation Expense - Stock Option Plan	(78,253)	0
Customer Advances	750,823	632,496
Deferred Compensation Plan Reserve	8,123,821	0
Deferred Connection Fees	8,272,111	7,625,353
Early Retirement Obligaton	3,793,152	4,180,979
End of Life Nuclear Fuel Amortization	2,857,120	3,632,616
Executive Long Term Incentive Plan	3,328	0
FAS 109 - Effect of Rate Changes	41,337,929	26,355,105
FAS 109 - ITC Grossup	96,542,190	88,764,712
Low Level Radiation Waste	0	361,416
Lower of Cost of Market on s Inventories	0	574,012
Medical Deduction - Self Insured	3,618,814	1,555,168
Nuclear Fuel Disposal - Prairie Island	10,448,043	10,448,043
Nuclear Plant - Decommissioning Provisions	90,515,363	97,802,020
Pending Lawsuits	1,944,044	1,865,420
Post Employment Benefits	0	3,903,563
Post Retirement Benefits	0	5,936,074
Rate Refunds	908,326	0
Saver Switches - Minnesota	572,337	1,684,838
Saver Switches - North Dakota	1,850	48,803
Saver Switches - South Dakota	47,594	119,292
Severance Accrual	937,125	298,780
Spare Parts Inventory Reserve-Customer Refund	110,369	0
Trust Fund Interest Capitalized	1,116,978	1,005,593
Unbilled Revenues	1,911,026	1,398,066
Unfunded Pension Liability	5,532,071	4,869,695
Workers Compensation	177,506	155,444
	296,730,573	284,633,166

< P234-10(b)) >

Gas (Other)	Bal at Beg of Year	Bal at End of Year
Accrued Vacation Paid	512,861	664,048
Avoided Tax Interest	266,458	519,350
Bad Debts	61,622	104,217
Compensation Expense - Stock Option Plan	(7,535)	0
Customer Advances	0	0
Deferred Compensation Plan Reserve	748,874	0
Deferred Connection Fees	2,120,426	2,153,452
Early Retirement Obligation	296,769	429,320
Executive Incentive Pay	216	0
FAS 109 - Effect of Rate Changes	3,314,071	2,112,895
FAS 109 - ITC Grossup	7,739,810	7,116,288
Medical Deduction - Self Insured	331,826	159,292
Pending Lawsuit	312,453	164,025
Post Employment Benefits	0	400,835
Post Retirement Benefits	0	609,542
Severance Accrual	90,258	30,680
Unfunded Pension Costs	532,814	500,042
Workers Compensation	17,106	15,962
Deferred CIAC - Surcharge	0	38,311
	16,338,029	15,018,659

< P234-17(b)) >

Nonutility	Bal at Beg of Year	Bal at End of Year
Bad Debts	70,262	53,542
Desars and Casars Book Reserve	0	382,602
Executive Long Term Incentive Plan	0	385,489
Rate Refund	0	130,659
Deferred Compensation Plan Reserve	0	9,222,996
Reference Plant Design Costs	1,047,672	0
Environmental & Regulatory Reserve	3,462,900	6,276,845
	$4,580,834	$16,459,133

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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	103.00
11	Variable Rate Series B		100.00	103.00
12				
13	* TOTAL PREFERRED STOCK	7,000,000		
14				
15	* Common Stock	160,000,000	2.50	
16	Leveraged Common Stock held by			
17	Employee Stock Ownership Plan			
18				
19	TOTAL COMMON STOCK	160,000,000		
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35	**Notes:**			
36				
37	< P250-13(a) >			
38	New York Stock Exchange except Series A and B.			
39				
40	< P250-15(a) >			
41	New York Stock Exchange, Chicago Stock Exchange and Pacific Stock Exchange.			
42				

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
66,922,144	167,305,359					15
						16
		59,445	(2,990,217)			17
						18
66,922,144	167,305,359	59,445	(2,990,217)	0	0	19
						20
						21
						22
						23
						24
						25
						26
						27
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						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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 an 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	2,361,932	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			
36	Reduction of premium associated with retirement of Treasury		
37	Stock in 1991	(1,539,432)	(9,058,701)
38			
39			
40			
41			
42			
43			
44			
45			
46	TOTAL	67,066,144	$549,228,342

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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 an 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		(1,284)
29			
30			
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43			
44			
45			
46	TOTAL	68,462,384	$549,696,583

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 in 1993 and 1992.	(3,351,793)
4		
5	Subtotal	(3,351,793)
6		
7		
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40	TOTAL	($3,351,793)

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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 - FIRST MORTGAGE BONDS SERIES DUE:		
2	June 1, 1995 - 6.125	30,000,000	498,242
3			(505,500) P
4	August 1, 1996 - 5.875	45,000,000	642,670
5			(675,000) P
6	October 1, 1997 - 6.50	30,000,000	382,379
7			(225,000) P
8	October 1, 1997 - 5.875	100,000,000	993,468
9			195,000 D
10	May 1, 1998 - 6.75	45,000,000	417,278
11	February 1, 1999 - 5.50	200,000,000	1,016,938
12			350,000 D
13			
14			
15	December 1, 2000 - 5.75	100,000,000	1,017,166
16			517,000 D
17			
18			
19			
20			
21	October 1, 2001 - 7.875	150,000,000	1,036,975
22			600,000 D
23	March 1, 2002 - 7.375	50,000,000	550,036
24			(150,000) P
25	February 1, 2003 - 7.50	50,000,000	428,694
26			(375,000) P
27	April 1, 2003 - 6.375	80,000,000	858,430
28			320,000 D
29	January 1, 2004 - 8.375	75,000,000	748,735
30			(375,000) P
31	December 1, 2005 - 6.125	70,000,000	746,598
32			644,700 D
33	TOTAL	$1,025,000,000	$9,658,809

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 supplemental statement, 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
06/01/67	06/01/95	06/01/67	06/01/95	0	270,625	2
						3
08/01/66	08/01/96	08/01/66	08/01/96	0	389,287	4
						5
10/01/67	10/01/97	10/01/67	10/01/97	0	287,145	6
						7
10/01/92	10/01/97	10/01/92	10/01/97	100,000,000	4,476,826	8
						9
05/01/68	05/01/98	05/01/68	05/01/98	0	447,623	10
02/01/94	02/01/99	02/01/94	02/01/99	200,000,000	9,679,569	11
						12
						13
						14
12/01/93	12/01/00	12/01/93	12/01/00	100,000,000	5,750,000	15
						16
						17
						18
						19
						20
10/01/94	10/01/01	10/01/94	10/01/04	150,000,000	2,559,375	21
						22
03/01/72	03/01/02	03/01/72	03/01/02	50,000,000	3,687,500	23
						24
02/01/73	02/01/03	02/01/73	02/01/03	50,000,000	3,750,000	25
						26
04/01/93	04/01/03	04/01/93	04/01/03	80,000,000	5,100,000	27
						28
01/01/74	01/01/04	01/01/74	01/01/04	0	35,214	29
						30
12/01/93	12/01/05	12/01/93	12/01/05	70,000,000	4,287,500	31
						32
[redacted]				$800,000,000	$40,720,664	33

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	July 1, 2019 - 9.125	$100,000,000	$1,282,154
2			875,000 D
3	June 1, 2020 - 9.375	100,000,000	310,676
4			875,000 D
5	Burnsville Pollution Control		
6	Series C - 6.2	8,800,000	279,847
7			
8	Pollution Control		
9	Series J, K and L - Var	13,700,000	788,833
10			
11			
12			
13			
14	Ramsey & Washington Counties		
15	Resource Recovery Series I - Var	27,700,000	611,625
16			
17	SUBTOTAL - ACCOUNT 221	1,275,200,000	14,681,944
18			
19	ACCOUNT 224		
20			
21	Public Improvements	1,691,819	
22			
23	Genstar - 9.00	9,484	
24	Mankato Service Center - 10.00	441,980	
25			
26	ESOP Loan - Var	15,000,000	
27			
28	* Guaranty Agmt - Pollution Control financing at average interest rates.		
29	Red Wing - 5.69	28,750,000	346,087
30	Monticello 1975 - 7.40	3,500,000	97,713
31	Monticello 1973 - 5.41	7,600,000	141,625
32			39,000 D
33	TOTAL	$1,332,193,283	$15,306,369

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 supplemental statement, 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.
07/01/89	07/01/19	07/01/89	07/01/19	$98,000,000	$9,026,145	1
						2
06/01/90	06/01/20	06/01/90	06/01/20	70,000,000	7,229,167	3
						4
						5
03/01/76	03/01/96	03/01/76	03/01/96	8,800,000	545,600	6
						7
						8
07/01/81	03/01/11	07/01/81	03/01/11	13,700,000	388,066	9
						10
						11
						12
						13
						14
12/01/84	12/01/06	12/01/84	12/01/06	22,300,000	1,480,500	15
						16
				1,012,800,000	59,390,142	17
						18
						19
						20
				1,090,513	40,017	21
						22
02/17/82	12/27/96			19,730	853	23
09/01/91	08/01/03			183,377	19,571	24
						25
04/20/93	04/20/93			2,697,526	324,230	26
						27
						28
05/01/73	Various	05/01/73	05/01/03	24,750,000	1,416,250	29
07/01/75	02/01/03	07/01/75	02/01/03	3,500,000	259,000	30
02/01/73	Various	02/01/73	02/01/03	5,900,000	320,531	31
						32
[redacted]				$1,050,941,146	$61,770,594	33

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	Sioux Falls - 5.78 - Ind. Dev. Rev. Bond	$940,000	$41,652
2	Inver Grove Hts 1975 - 7.125 - Ind. Dev. Rev. Bond	1,000,000	29,598
3			
4	Non-collateralized Poll Cont		
5	Becker 1987 - 7.25	9,000,000	257,088
6			
7	Anoka Cty Series 1985 - 7.00	29,750,000	605,664
8			
9	Becker Poll Cont 1989A - 6.80	60,000,000	784,380
10			1,050,000 D
11			
12	Becker Poll Cont 1992A - Var	27,900,000	242,682
13			
14	Becker Poll Cont 1993A - Var	50,000,000	247,188
15			
16	Becker Poll Cont 1993B - Var	50,000,000	228,326
17			
18			
19			
20	* SUBTOTAL - ACCOUNT 224	285,583,283	4,111,003
21			
22	Debt to Associated Companies (430)		
23			
24	SUBTOTAL	0	0
25			
26			
27			
28			
29			
30			
31	* (See footnote for reconciliation of column (i) total to		
32	Accounts 427 and 430)		
33	TOTAL	$1,560,783,283	$18,792,947

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 supplemental statement, 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.
10/01/73	Various	10/01/73	12/01/98	$255,000	$17,141	1
02/01/75	01/01/95	01/01/75	01/01/95	1,000,000	71,250	2
						3
						4
12/01/87	12/01/05	12/01/87	12/01/05	9,000,000	652,500	5
						6
12/01/85	12/01/08	12/01/85	12/01/08	25,150,000	1,571,179	7
						8
07/01/89	04/01/07	07/01/89	04/01/07	60,000,000	4,080,000	9
						10
						11
03/01/92	03/01/19	03/01/92	03/01/19	27,900,000	833,310	12
						13
09/01/93	09/01/19	09/01/93	09/01/19	50,000,000	1,506,153	14
						15
09/01/93	09/01/19	09/01/93	09/01/19	50,000,000	1,451,792	16
						17
						18
						19
				261,446,146	12,563,777	20
						21
					12,631	22
						23
				0	12,631	24
						25
						26
						27
						28
						29
						30
						31
						32
[redacted]				$1,274,246,146	$71,966,550	33

< P256.2-20(a) >

DETAIL FOR ACCOUNT 224 OF NET CHANGES DURING THE YEAR:

	BALANCE 12-31-93	ADDITIONS	REDUCTIONS	BALANCE 12-31-94
Public Inprovements	$527,409	$626,272	$63,168	$1,090,513
Genstar	18,876	854		19,730
Mankato Service Center	191,873	2,317	10,813	183,377
ESOP Loan	10,887,336	6,770,088	14,959,898	2,697,526
Guar Agmt - Poll Cont				
Red Wing	25,250,000	500,000	1,000,000	24,750,000
Monticello 1975	3,500,000			3,500,000
Monticello 1973	6,100,000	300,000	500,000	5,900,000
Ind Dev Rev Bonds				
Sioux Falls	310,000	115,000	170,000	255,000
Inver Grove Hts 1975	1,000,000			1,000,000
Non-collateralized Poll Cont				
Becker 1987	9,000,000			9,000,000
Anoka Cty Series 1985	26,100,000		950,000	25,150,000
Becker Poll Cont 1989A	60,000,000			60,000,000
Becker Poll Cont 1992A	27,900,000			27,900,000
Becker Poll Cont 1993A	50,000,000			50,000,000
Becker Poll Cont 1993B	50,000,000			50,000,000
Becker RDF Landfill	0			0
TOTAL	$270,785,494	$8,314,531	$17,653,879	$261,446,146

< P256.2-31(i) >

Total does not include $22,149 of interest expense accrual true-ups on redeemed bonds.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	$243,474,990
2	Reconciling Items for the Year	[redacted]
3		
4	Taxable Income Not Reported on Books	
5		* 85,001,061
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	[redacted]
10		* 395,121,729
11		
12		
13		
14	Income Recorded on Books Not Included in Return	[redacted]
15		* (5,621,980)
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	[redacted]
20		* (448,097,290)
21		
22		
23		
24		
25	Equity in Earnings of Subsidiary Companies	* (70,453,119)
26	Total Income Tax Expense	108,421,673
27	Federal Tax Net Income	307,847,064
28	Show Computation of Tax:	
29	35.00% of Federal Tax Net Income	107,746,472
30		
31	Plus:	
32	Adjustment of Prior Years	(3,319,215)
33		
34		
35	Total Federal Income Tax Payable	104,427,257
36		
37		
38		
39		
40		
41		
42		
43		
44		

< P261-5(b) >

TAXABLE INCOME NOT REPORTED ON BOOKS:

CIAC - Connection Fees	$3,260,453
Earnings on Non-Qualified External Decommissioning Fund	688,961
Income Earned on Annuity Payments	9,368
Tax Benefit Transfer Gain on Disposals	50,712
Tax Benefit Transfer Rental Income	77,357,076
Unbilled Revenues	3,634,491
TOTAL	$85,001,061

< P261-10(b) >

DEDUCTION RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Accrued Vacation Paid	$2,446,451
Ad Valorem Tax - Coal	268,368
Amortization of Regulatory Asset	759,500
Bad Debt Reserve	23,195
Book Depreciation	217,186,453
Book Nuclear Fuel Expense	56,111,423
Book Rent Expense - Capitalization for Tax	4,473,368
Coal Mine Restoration Reserve	413,861
Deferred Compensation Plan Reserve	1,208,860
Desars & Casars Book Reserve	565,452
Executive Long Term Incentive Plan	938,485
Interest Capitalized Under IRC Sect 263A	7,231,005
Lobbying Expense	2,500,000
Low Level Radiation Waste	888,000
Nuclear Decommissioning	34,297,272
Pathfinder Decommissioning	50,018
Pension Liability	993,724
Post Employment Benefits - FAS 112	10,575,916
Post Retirement Benefits - FAS 106	16,194,095
Property Taxes 481a Adjustment	27,166,996
Rate Refund	10,341
Regulatory Reserve	5,499,336
Reuseable Material Pricing Adjustment	9,706
Spare Parts Change of Accounting	3,701,134
Travel and Entertainment Exclusion	1,600,000
TOTAL	$395,121,729

< P261-15(b) >

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:

AFDC Equity	($3,863,034)
Book Tax Benefit Transfer Income	(943,645)
CIAC - Customer Advances	(245,193)
Increase in Cash Surrender Value - Wealth Op	(570,108)
TOTAL	($5,621,980)

< P261-20(b) >

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

AFDC Debt	($7,351,547)
Book Unamortized Cost of Retired Debt Over Amort	(4,365,514)
Decontamination and Decomissioning Asset	(756,577)
Deferred Gas Costs	(6,459,384)
Environmental Cleanup	(868,632)
ESOP Dividends & Plan Contributions	(8,524,038)
External Qualified Nuclear Decommissioning Funding	(15,619,032)
Fees on Non-Qualified Externally Funded Nuclear Decommissioning	(157,443)
Insurance Settlements	(163,433)
Interest Expense - Capital Leases	(1,909,888)
Internally Developed Software	(7,970,702)
Loss - Sales of Fixed Assets	(2,297,603)
Maintenance Contracts	(406,276)
Medical Deductions Self Insured	(83,015)
Nuclear Fuel Removal Fee - 1 M/KWH	(10,558,803)
Pending Lawsuits	(616,500)
Prepaid Insurance	(286,702)
Pucip Deduction, Net of Book Amortizaton	(24,070,272)
Severance Accrual	(1,198,938)
Spare Parts Inventory Reserve	(36,619)
State Income Tax Deduction	(32,519,253)
Stock Loss on External Decommissioning Fund	(1,074,135)
Tax Benefit Transfer Amortization Expense	(96,401)
Tax Benefit Transfer Interest Expense	(47,433,691)
Tax Depreciation	(257,544,443)
Tax Removal Cost Over Book Accrual	(6,487,835)
Tax Repair Allowance	(9,187,101)
Workers Compensation	(53,513)
TOTAL	(448,097,290)

< P261-25(b) >

Nothern State Power Company (Minnesota) is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 1994. The other members of the affiliated group and the Federal Income tax provision of each are:

Northern States Power Company (Wisconsin)	9,365,648
United Power and Land Company	314,927
Cenergy, Inc.	(321,644)
Cormorant Corporation	98,000
Eloigne Corporation	(344,072)
First Midwest Auto Park Inc.	571,636
NRG Energy, Inc.	1,694,261
Viking Gas Transmission Company	(178,875)

The consolidated Federal Income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocated 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.

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

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

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

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

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	FEDERAL TAXES					
2						
3	Income Tax - 1994	2,501,059		104,427,256	111,814,000 *	4,647,472
4	- 1993				427,002	
5						
6	FICA - 1994	32,696		25,209,991	24,751,714	
7	- 1993					
8						
9	Fed Unemployment - 1994	6,145		414,364	410,546	
10	- 1993					
11						
12	SUBTOTAL	2,539,900	0	130,051,611	137,403,262	4,647,472
13						
14	STATE TAXES-MINNESOTA					
15						
16	Income Tax - 1994	1,156,025		30,420,655	28,581,679 *	(1,877,686)
17	- 1993				146,089	
18						
19	Unemployment - 1994	(159,663)		2,430,691	2,406,140	
20	- 1993					
21						
22	Motor Vehicle - 1994	(18,048)		18,197	18,047	
23	- 1993					
24						
25	LOCAL TAXES-MINNESOTA					
26						
27	Real Estate - 1994	95,873,733		99,332,681	95,541,777	16,788
28	- 1993					
29						
30	Personal Property - 1994	61,876,336		65,056,319		(16,788)
31	- 1993				60,744,084	
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	$161,268,283		$327,310,154	$324,841,078	$2,769,786

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. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2, and 409.2 under other accounts in column (i). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

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(Show utility department where applicable and account 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
(665,215)		93,063,367			* 11,363,889	3
						4
						5
490,973		16,726,829			* 8,483,162	6
						7
						8
9,963		274,516			* 139,848	9
						10
						11
(164,279)		110,064,712			19,986,899	12
						13
						14
						15
971,226		28,267,585			* 2,153,070	16
						17
						18
(135,112)		1,642,904			* 787,787	19
						20
						21
(17,898)		0			* 18,197	22
						23
						24
						25
						26
99,681,425		97,124,491			* 2,208,190	27
						28
						29
66,171,783		52,926,666			* 12,129,653	30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
$166,507,145		$290,026,358			$37,283,796	41

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 - 1994	706,192		11,341,174	10,483,298	
4	- 1993				706,192	
5						
6	St Paul - 1994	965,104		14,089,341	13,058,489	
7	- 1993				965,104	
8						
9	South St Paul - 1994	102,678		418,717	323,312	
10	- 1993				102,678	
11						
12	White Bear Lake - 1994	134,382		147,674	2,258	
13	- 1993				134,382	
14						
15	Winona - 1994	117,591		425,269	304,366	
16	- 1993				117,591	
17						
18	Lake City - 1994	34,538		34,581		
19	- 1993				34,538	
20						
21	West St Paul - 1994	228,031		463,689	216,355	
22	- 1993				228,031	
23						
24	Coon Rapids - 1994	22,757		337,705	311,938	
25	- 1993				22,757	
26						
27	FRANCHISE-MINNESOTA					
28	East Grand Forks - 1994	55,303		74,389		
29	- 1993				55,303	
30						
31	Moorhead - 1994	33,111		245,196	217,662	
32	- 1993				33,111	
33						
34	Moundsview - 1994	23,526		224,134	200,590	
35	- 1993				23,526	
36						
37	St Cloud - 1994	97,621		1,133,674	1,027,871	
38	- 1993				97,621	
39						
40	SUBTOTAL	161,249,217	0	226,194,086	216,104,789	(1,877,686)
41	TOTAL	$163,789,117	0	$356,245,697	$353,508,051	$2,769,786

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2, and 409.2 under other accounts in column (i). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

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(Show utility department where applicable and account 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
857,876		11,315,979			*	25,195	3
							4
							5
1,030,852		10,529,152			*	3,560,189	6
							7
							8
95,405		189,594			*	229,123	9
							10
							11
145,416		145,307			*	2,367	12
							13
							14
120,903		590,676			*	(165,407)	15
							16
							17
34,581		0			*	34,581	18
							19
							20
247,334		461,507			*	2,182	21
							22
							23
25,767		337,164			*	541	24
							25
							26
							27
74,389		0			*	74,389	28
							29
							30
27,534		0			*	245,196	31
							32
							33
23,544		142,393			*	81,741	34
							35
							36
105,803		862,924			*	270,750	37
							38
							39
169,460,828	0	204,536,342	0	0		21,657,744	40
$169,296,549	0	$314,601,054	0	0		$41,644,643	41

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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

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

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	STATE TAXES-NORTH DAKOTA					
2						
3	Income Taxes - 1994	1,463,425		1,157,598	939,000	* (1,586,969)
4	- 1993				52	
5						
6	Unemployment - 1994	(387)		8,750	8,714	
7	- 1993					
8						
9	Motor Vehicle - 1994	(56)		2,205	2,205	
10	- 1993					
11						
12	Personal Property - 1994	2,536,652		2,396,114		
13	- 1993				2,534,816	
14						
15	LOCAL TAXES-NORTH DAKOTA					
16						
17	Real Estate - 1994	(2,015)		4,914		
18	- 1993				4,914	
19						
20	FRANCHISE-NORTH DAKOTA					
21						
22	Fargo - 1994	131,966		1,267,658	1,167,078	
23	- 1993				131,966	
24						
25	Grand Forks - 1994	172,895		684,380	518,220	
26	- 1993				172,895	
27						
28	Larimore - 1994	3,186		13,800	10,691	
29	- 1993				3,186	
30						
31	Hatton - 1994	2,078		8,390	6,346	
32	- 1993				2,078	
33						
34	SUBTOTAL	4,307,744	0	5,543,809	5,502,161	(1,586,969)
35						
36						
37						
38						
39						
40						
41	TOTAL	$168,096,861	0	$361,789,506	$359,010,212	$1,182,817

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. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2, and 409.2 under other accounts in column (i). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

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(Show utility department where applicable and account 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
95,002		1,013,770			* 143,828	3
						4
						5
(351)		4,618			* 4,132	6
						7
						8
(56)		0			* 2,205	9
						10
						11
2,397,950		1,735,655			* 660,459	12
						13
						14
						15
						16
(2,015)		1,268			* 3,646	17
						18
						19
						20
						21
100,580		912,475			* 355,183	22
						23
						24
166,160		499,354			* 185,026	25
						26
						27
3,109		13,794			* 6	28
						29
						30
2,044		8,390			0	31
						32
						33
2,762,423		4,189,324			1,354,485	34
						35
						36
						37
						38
						39
						40
$172,058,972	0	$318,790,378	0	0	$42,999,128	41

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

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

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

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

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	STATE TAXES-SOUTH DAKOTA					
2						
3	Motor Vehicle - 1994	(283)		12,394	12,394	
4	- 1993					
5						
6	Personal Property - 1994	1,626,276		2,075,659		
7	- 1993				1,599,236	
8						
9	Unemployment - 1994	(2,518)		8,910	9,017	
10	- 1993					
11						
12	Workers Compensation - 1994	(1,175)		1,175		
13	- 1993					
14						
15	LOCAL TAXES-SOUTH DAKOTA					
16						
17	Real Estate - 1994	108,800		72,830		
18	- 1993				70,103	
19						
20	SUBTOTAL	1,731,100	0	2,170,968	1,690,750	0
21						
22	STATE TAXES-WISCONSIN					
23						
24	Unemployment - 1994	2,528		620		
25	- 1993					
26						
27	SUBTOTAL	2,528	0	620	0	0
28						
29						
30						
31						
32						
33						
34						
35	* Other Sales Tax					
36						
37						
38						
39						
40						
41	TOTAL	$169,830,489	0	$363,961,094	$360,700,962	$1,182,817

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2, and 409.2 under other accounts in column (i). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

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(Show utility department where applicable and account 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			* 12,394	3
						4
						5
2,102,699		1,[illegible]5,875			* 429,784	6
						7
						8
(2,625)		5,378			* 3,532	9
						10
						11
0		0			0	12
						13
						14
						15
						16
111,527		72,830			0	17
						18
						19
2,211,318		1,724,083			445,710	20
						21
						22
						23
3,148		0			* 620	24
						25
						26
3,148					620	27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
$174,273,438	0	$320,514,461	0	0	$43,445,458	41

< P262-3(f) >

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

< P262-16(f) >

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

< P262.2-3(f) >

Transfer of Long-term Taxes Receivable

< P262.3-35(b)(g) >

Total does not include state and local use taxes of $242,175 in column (b) and $345,499 in column (g).

< P263-3(l) >

Includes $8,182,928-Gas Utility; $3,180,962-Acct. No. 409.2; ($1)-Other.

< P263-6(l) >

Includes $1,805,035-Gas Utility; $3,473,937-Acct. No. 107 & 108; $3,204,190-Other.

< P263-9(l) >

Includes $29,627-Gas Utility; $57,182-Acct. No. 107 & 108; $53,039-Other.

< P263-16(l) >

Includes $2,485,528-Gas Utility; ($332,458)-Acct No. 409.2.

< P263-19(l) >

Includes $165,773-Gas Utility; $328,629-Acct. No. 107 & 108; $293,385-Other.

< P263-22(l) >

Acct. No. 184.

< P263-27(l) >

Includes $1,215,745-Gas Utility; $260,102-Acct. No. 107; $871,788-Acct. No. 408.2; ($139,445)-Other.

< P263-30(l) >

Includes $11,781,395-Gas Utility; $344,204-Acct. No. 107; $4,054-Other.

< P263.1-3(l) >

Other.

< P263.1-6(l) >

Includes $3,499,676-Gas Utility; $60,513-Other.

< P263.1-9(l) >

Includes $187,905-Gas Utility; $41,218-Other.

< P263.1-12(l) >

Other.

< P263.1-15(l) >

Other.

< P263.1-18(l) >

Includes $34,270-Gas Utility; $311-Other.

< P263.1-21(l) >

Other.

< P263.1-24(l) >

Other.

< P263.1-28(l) >

Includes $70,160-Gas Utility; $4,229-Other.

< P263.1-31(l) >

Includes $244,367-Gas Utility; $829-Other.

< P263.1-34(l) >

Includes $83,890-Gas Utility; ($2,149)-Other.

< P263.1-37(l) >

Includes $261,668-Gas Utility; $9,082-Other.

< P263.2-3(l) >

Includes $89,139-Gas Utility; $54,689-Acct. No. 409.2.

< P263.2-6(l) >

Includes $1,377-Gas Utility; $1,414-Acct. No. 107 & 108; $1,341-Other.

< P263.2-9(l) >

Acct. No. 184.

< P263.2-12(l) >

Includes $652,337-Gas Utility; $8,122-Acct. No. 107.

< P263.2-17(l) >

Includes $186-Gas Utility; $3,460-Acct. No. 408.2.

< P263.2-22(l) >

Includes $571,605-Gas Utility; ($216,422)-Other.

< P263.2-25(l) >

Includes $174,197-Gas Utility; $10,829-Other.

< P263.2-28(l) >

Other.

< P263.3-3(l) >

Acct. No. 184.

< P263.3-6(l) >

Includes $429,785-Acct. No. 107; ($1)-Other.

< P263.3-9(l) >

Includes $1-Gas Utility; $2,106-Acct. No. 107 & 108; $1,425-Other.

< P263.3-24(l) >

Other.

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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%	9,169,738				383,912	(582)
4	7%						
5	10%	127,557,670				7,312,528	(1,082,611)
6							
7							
8	TOTAL	$136,727,408				$7,696,440	($1,083,193)
9	Other (List separately and show 3%,4%,7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	381,625				30,930	(21)
13	10%	8,922,287				386,740	(116,677)
14							
15	Common Utility						
16	4%	32,432				2,315	0
17	10%	881,950				119,706	9
18							
19							
20	NON-OPERATING						
21							
22	Non Utility						
23	10%	13,422,570					(2,549,214)
24							
25	Non Utility-RDF						
26	10%	853,286				54,756	
27							
28							
29	(a) Common Alloc						
30	Electric	742,533				103,511	8
31	Gas	171,849				18,511	1
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	Adjustment Explanation	Line No.
			1
			2
8,785,244			3
		< P267 >	4
119,162,531		1) Adjustments consist of:	5
			6
		- True-ups of deferred tax credits recorded to reflect difference	7
$127,947,775		between tax returns filed and prior year accounting accruals:	8
		Affecting Income (1,199,882) Not affecting Income 0	9
			10
		- Amortization of non-utility tax benefits transfer (safe harbor)	11
350,674		lease credits which have no income effect (2,549,[illegible]4)	12
8,418,870			13
		- Transfer of non-utility assets and associated tax credits	14
		to wholely owned subsidiary 0	15
30,117			16
762,253		- Miscellaneous income adjustments 0	17
			18
		TOTAL (3,749,096)	19
			20
		2) Credits are flowed-through (amortized) to income ratably over the	21
		estimated life of the property.	22
10,873,356			23
			24
		3) Reconciliation of page 114, line 18:	25
798,530		- Allocations to current year's net income (8,290,887)	26
		(column (f) on page 256)	27
			28
		- Less non-utility portion 54,755	29
639,030			30
153,339		- Return to accrual adjustments per (1) above (1,199,882)	31
			32
		- Miscellaneous income adjustments per (1) above 0	33
			34
		Utility Investment Tax Credit Adjustment (9,436,014)	35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 Pension Costs - FASB 87	8,703,000	*	4,805,000		3,898,000
5						
6	Unfunded Early Retirement Costs	11,510,000			0	11,510,000
7	(1988 Program)					
8						
9						
10	LONG-TERM OBLIGATIONS FOR DEFERRED					
11	COMPENSATION PROGRAMS:					
12						
13	Unfunded Nonqualified Pension	3,621,000		0	390,573	4,011,573
14	Benefits Costs					
15						
16	Deferred Compensation - Salary	15,637,303	*	3,213,030	2,604,241	15,028,514
17	Deferrals					
18						
19	Deferred Compensation - Accrued	3,905,062	*	2,301,845	2,424,512	4,027,729
20	Earnings					
21						
22						
23	LONG-TERM ACCRUALS FOR OTHER					
24	EXPENSE ITEMS:					
25						
26	Injury Compensation - FASB 112	0		0	8,895,774	8,895,774
27						
28	Environmental & Regulatory	9,922,889	*	3,138,270	8,637,607	15,422,226
29	Reserves					
30						
31	Hazardous Waste Disposal	0	524	238,000	1,126,000	888,000
32						
33						
34	LONG-TERM DEPOSITS, ADVANCE					
35	BILLINGS & RECEIPTS:					
36						
37	Intercompany billings - Subsidiary	0		0	1,711,000	1,711,000
38	Pension Funding					
39						
40	Koch Refinery Maintenance Reserve	814,283	*	135,720	0	678,563
41						
42	Other	3,700		0	1,700	5,400
43						
44						
45						
46						
47	TOTAL	$54,117,237		$13,831,865	$25,791,407	$66,076,779

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	DEFERRED INCOME ITEMS:					
2						
3	IPP Power Contract Billing	0		0	2,277,672	2,277,672
4	Adjustments					
5						
6	Other	500		0	0	500
7						
8	Settlements	163,333	*	1,772,356	1,609,023	0
9						
10	Spare Parts	232,574	*	259,828	27,254	0
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	$54,513,644	[redacted]	$15,864,049	$29,705,356	$68,354,951

< P269-4(c) >

Accounts charged include:	184	$2,788,000
	254	2,017,000
	TOTAL	$4,805,000

< P269-16(c) >

Accounts charged include:	182.3	$1,339,000
	232	67,718
	253	1,401,282
	NRG	177,625
	421	227,220
	920	185
	TOTAL	$3,213,030

< P269-19(c) >

Accounts charged include:	232	$2,229,540
	253	6,169
	NRG	18,052
	421	48,084
	TOTAL	$2,301,845

< P269-28(c) >

Accounts charged include:	143	$1,010
	154	306
	184	58
	232	178,116
	242	1,825,199
	253	1,133,581
	TOTAL	$3,138,270

< P269-40(c) >

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

< P269.1-8(c) >

Accounts charged include:	107	$584,131
	131	978,333
	232	40
	930.2	209,852
	TOTAL	$1,772,356

< P269.1-10(c) >

Accounts charged include:	419.1	$10,098
	432	6,405
	456	243,325
	TOTAL	$259,828

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Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	4,361,510	0	435,165
5	Other			
6				
7				
8	TOTAL Electric(Enter Total of lines 3 thru 7)	$4,361,510	0	$435,165
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)	$4,361,510	0	$435,165
18	Classification of TOTAL			
19	Federal Income Tax	4,361,510		435,165
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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

income and deductions.

3. Use separate pages 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
							2
							3
	0					3,926,345	4
							5
							6
							7
0	0					$3,926,345	8
[redacted]							9
							10
							11
							12
							13
							14
							15
							16
0	0					$3,926,345	17
[redacted]							18
						3,926,345	19
							20
							21

NOTES(Continued)

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	$765,877,343	$43,991,752	$34,545,975
3	Gas	51,084,116	3,854,728	1,364,622
4	Other (Define)	0	0	0
5	TOTAL (Enter Total of lines 2 thru 4)	$816,961,459	$47,846,480	$35,910,597
6	Other (Specify) Non-Operating	6,925,918	0	0
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$823,887,377	$47,846,480	$35,910,597
10	Classification of TOTAL			
11	Federal Income Tax	664,483,580	38,564,796	29,148,052
12	State Income Tax	159,403,797	9,281,684	6,762,545
13	Local Income Tax			

NOTES

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

income and deductions.

3. Use separate pages 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		$7,452,368		$22,859,565	$790,730,317	2
0	0		1,969,151		0	51,605,071	3
0	0		0		0	0	4
0	0		$9,421,519		$22,859,565	$842,335,388	5
(415,277)	0		0		0	6,510,641	6
							7
							8
($415,277)	0		$9,421,519		$22,859,565	$848,846,029	9
[redacted]							10
(320,785)	0		7,353,321		18,346,096	684,572,314	11
(94,492)	0		2,068,198		4,513,469	164,273,715	12
							13

NOTES(Continued)

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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			
3	Electric	$79,393,683	$16,298,465	$25,410,380
4				
5				
6				
7				
8	Other	0	0	0
9	TOTAL Electric (Total of lines 3 thru 8)	$79,393,683	$16,298,465	$25,410,380
10	Gas			
11	Gas	4,267,047	3,863,028	1,745,711
12				
13				
14				
15				
16	Other	0	0	0
17	TOTAL Gas (Total of lines 11 thru 16)	$4,267,047	$3,863,028	$1,745,711
18	Other (Specify)	81,778,077	0	0
19	TOTAL (Acct 283) (Enter Total of lines 9,17 and 18)	$165,438,807	$20,161,493	$27,156,091
20	Classification of TOTAL			
21	Federal Income Tax	131,599,863	15,760,742	21,400,220
22	State Income Tax	33,838,944	4,400,751	5,755,871
23	Local Income Tax	0	0	0

NOTES

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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 separate pages 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		0		$103,815,846	$174,097,614	3
							4
							5
							6
							7
0	0		0		0	0	8
0	0		0		$103,815,846	$174,097,614	9
[redacted]							10
0	0		0		6,890,996	13,275,360	11
							12
							13
							14
							15
0	0		0		0	0	16
0	0		0		$6,890,996	$13,275,360	17
0	0		81,778,077		0	0	18
0	0		$81,778,077		$110,706,842	$187,372,974	19
[redacted]							20
0	0		65,880,419		88,449,759	148,529,725	21
0	0		15,897,658		22,257,083	38,843,249	22
0	0		0		0	0	23

NOTES (Continued)

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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		0	5,937,000	11,054,000
4	FASB 87 Levels				
5					
6					
7	INCOME TAX ITEMS:				
8					
9	ITC Gross-Up to Pretax Rate Levels - FASB 109	283	8,401,000	0	95,881,000
10					
11	Deferred Taxes Collected in Rates in Excess of	283	35,304,000	0	72,150,000
12	Current Tax Accrual Levels - FASB 109				
13					
14	Deferrals of IRS & State Interest/Other Credits	236	396,495	340,177	(56,318)
15		411	1,935,400		
16					
17					
18	OTHER INCOME ITEMS DEFERRED DUE TO EXPECTED RATE				
19	FLOWBACK:				
20					
21	Fuel Refunds	431	89	70,919	492,594
22					
23	Unrealized Gain on Decommissioning Trust	128	6,697,910	8,485,285	1,412,361
24	Investments - FASB 115	254	375,014		
25					
26	Interest Income from DOE Fuel Disposal	143	931,186	1,413,407	1,438,152
27	Fee Credits	WI	54,343		
28					
29	Gains from Sales of Emission Allowances		0	122,995	211,461
30					
31	Gas Site Remediation Reimbursement	407.4	92,930	100,674	185,860
32		495	100,674		
33					
34	Spare Parts Inventory	456	36,619		0
35					
36	Deferred Revenue - Citibank	142	66,670		0
37					
38					
39					
40					
41	TOTAL		$54,392,330	$16,470,457	$182,769,110

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	$567,834,077	$536,875,172
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr.4)	297,444,415	275,673,227
5	Large (or Ind.) (See Instr.4)	* 716,733,139	678,834,916
6	(444) Public Street and Highway Lighting	16,260,400	16,415,589
7	(445) Other Sales to Public Authorities	8,097,574	8,312,999
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	243,282	223,975
10	TOTAL Sales to Ultimate Consumers	$1,606,612,887	$1,516,335,878
11	(447) Sales for Resale	$128,824,875	$143,488,544
12	TOTAL Sales of Electricity	$1,735,437,762	$1,659,824,422
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	$1,735,437,762	$1,659,824,422
15	Other Operating Revenues		
16	(450) Forfeited Discounts	$4,328,798	$3,783,680
17	(451) Miscellaneous Service Revenues	3,173,440	3,561,522
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,528,680	1,561,042
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	* 207,071,766	190,384,762
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	$216,102,684	$199,291,006
27	TOTAL Electric Operating Revenues	* $1,951,540,446	$1,859,115,428

Notes:

< P300-5(b) >
Commercial and industrial sales are classified as "Large" if customer has a minimum registered demand of 100 KW or more.

< P300-21(b) >
Includes reimbursement from Northern States Power Co. (Wi) for production and transmission costs shared under an interchange agreement between the companies dated Sept. 17, 1984.

Fixed Production Expense	$103,709,273
Variable Production Expense	$70,566,190
Transmission Expense	$12,646,702

< P300-27(b) >
Includes $(2,441,996) unbilled revenues.

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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 page 108, 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		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
[redacted]				1
7,660,822	7,464,634	1,051,504	1,040,991	2
[redacted]				3
4,722,237	4,473,489	130,108	131,164	4
15,567,666	14,948,032	6,871	7,759	5
* 139,235	142,003	1,285	1,507	6
138,120	147,426	2,539	2,555	7
				8
13,482	12,404			9
28,241,562	27,187,988	1,192,307	1,183,976	10
6,294,467	7,622,098	59	60	11
34,536,029	34,810,086	1,192,366	1,184,036	12
				13
* 34,536,029	34,810,086	1,192,366	1,184,036	14

Notes:

< P301-6(d) >

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

< P301-14(d) >

Includes (8,748) MWH relating to unbilled revenues.

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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," page 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	AD Res Duplex (CL)	19,850	$1,481,339		2,214	8,966	7.4627¢
2	AE Res Load Ctrl	777,090	55,560,251		86,531	8,980	7.1498¢
3	AP Auto Prot Lgt	9,744	1,147,627	*	13,289	733	11.7809¢
4	AR Res	6,146,532	467,401,321		900,285	6,827	7.6043¢
5	AT Res TOD	812	54,597		76	10,684	6.7238¢
6	AW Limited Off-Peak	2,420	75,345	*	409	5,917	3.1134¢
7	. Unbilled	(13,574)	(932,243)				6.8679¢
8	Total Res w/o Space Heating	6,942,874	524,788,537		1,002,804	6,923	7.5587¢
9							
10	AA Res SH	674,499	41,015,107		46,326	14,560	6.0808¢
11	AB Res TOD SH	1,311	74,031		42	31,214	5.6469¢
12	AF Res Load Strl SH	25,650	1,475,216		1,243	20,636	5.7513¢
13	AJ Res Duplex SH (CL)	290	16,751		13	22,308	5.7762¢
14	AL Energy Ctrl DF	14,009	513,072	*	1,076	13,020	3.6624¢
15	. Unbilled	2,189	(48,637)				(2.2219)¢
16	Total Res w Space Heating	717,948	43,045,540		48,700	14,742	5.9956¢
17							
18	DC Small General	914,207	67,847,678		76,631	11,930	7.4215¢
19	DH Peak Ctrl Tier 2 Level A	363	21,894		3	121,000	6.0314¢
20	DI Peak Ctrl Tier 2 Level B	134	9,540		1	134,000	7.1194¢
21	DJ Peak Ctrl Tier 2 Level C	892	43,697		3	297,333	4.8988¢
22	DK General	3,380,801	205,451,036		31,480	107,395	6.0770¢
23	DL Energy Ctrl DF	1,631	62,910	*	53	30,774	3.8571¢
24	DP Peak Ctrl	77,350	4,641,930		446	173,430	6.0012¢
25	DP Auto Prot Lgt	28,760	3,279,648	*	14,514	1,982	11.4035¢
26	DT Small General TOD	321,441	16,518,260		6,811	47,194	5.1388¢
27	DW Limited Off-Peak	1,621	65,889	*	166	9,765	4.0647¢
28	. Unbilled	(4,963)	(498,067)				10.0356¢
29	Total Small Comm & Ind	4,722,237	297,444,415		130,108	36,295	6.2988¢
30							
31	GE Demand Free Power	34	1,344	*	3	11,333	3.9529¢
32	GH Peak Ctrl Tier 2 Level A	41,935	2,102,804		23	1,823,261	5.0144¢
33	GI Peak Ctrl Tier 2 Level B	78,618	3,488,864		23	3,418,174	4.4377¢
34	GJ Peak Ctrl Tier 2 Level C	468,196	16,437,117		34	13,770,471	3.5107¢
35	GK General	6,306,034	326,011,073		4,516	1,396,376	5.1698¢
36	GL Energy Ctrl	349,364	12,150,511		69	5,063,246	3.4779¢
37	GN Standby	20,126	930,601		4	5,031,500	4.6239¢
38	GP Peak Ctrl	2,838,795	129,408,208		1,369	2,073,627	4.5586¢
39	GQ Energy Ctrl-Rider	2,892	155,237		1	2,892,000	5.3678¢
40	GR Energy Ctrl-Rider	161,127	5,412,730		4	40,281,750	3.3593¢
41	Total Billed						
42	Total Unbilled Rev. (See Instr. 6)						
43	TOTAL	22,650,180	$1,361,376,981		1,187,658	19,071	6.0104¢

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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," page 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	GT General TOD	5,298,636	$221,812,589	820	6,461,751	4.1862¢
2	GW Limited Off-Peak	680	25,159 *	3	226,667	3.6999¢
3	GY Peak Ctrl Tier 1 Level B	1,418	57,742	1	1,418,000	4.0721¢
4	GZ Peak Ctrl Tier 1 Level C	13,379	503,450	1	13,379,000	3.7630¢
5	. Unbilled	(13,568)	(1,764,290)			13.0033¢
6	Total Large Comm & Ind	15,567,666	716,733,139	6,871	2,265,706	4.6040¢
7						
8	KP Street Lighting System	51,920	11,992,541	752	69,043	23.0981¢
9	KS Street Lighting Energy	11,579	701,159	45	257,311	6.0554¢
10	KY Street Lighting Energy	75,700	3,549,689	488	155,123	4.6892¢
11	. Unbilled	36	17,011			47.2528¢
12	Total Str & Hwy Lighting	139,235	16,260,400	1,285	108,354	11.6784¢
13						
14	M2 Municipal Water Pumping	101,758	5,973,022	808	125,938	5.8698¢
15	M3 Municipal Sewage Pumping	36,434	2,146,612	1,211	30,086	5.8918¢
16	M4 Fire/CD Siren	0	29,978	518	0	
17	M5 Excess Energy St Anthony	720	9,092	2	360,000	1.2628¢
18	. Unbilled	(792)	(61,130)			7.7184¢
19	Total Other Sales	138,120	8,097,574	2,539	54,399	5.8627¢
20						
21	Interdepartment Sales	13,482	243,282			1.8045¢
22	Total Inderdepartment Sales	13,482	243,282	0		1.8045¢
23						
24	Sales for Resale	6,272,543	127,979,515	59	106,314,288	2.0403¢
25	. Unbilled	21,924	845,360			3.8559¢
26	Total Sales for Resale	6,294,467	128,824,875	59	106,685,881	2.0466¢
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed	34,544,777 *	$1,737,879,758	1,192,366	28,972	5.0308¢
42	Total Unbilled Rev.(See Instr. 6)	(8,748)	($2,441,996)			27.9149¢
43	TOTAL	34,536,029	$1,735,437,762	1,192,366	28,964	5.0250¢

< P304-3(d) >
Indicates duplicate customers

< P304-6(d) >
Indicates duplicate customers

< P304-14(d) >
Indicates duplicate customers

< P304-23(d) >
Indicates duplicate customers

< P304-25(d) >
Indicates duplicate customers

< P304-27(d) >
Indicates duplicate customers

< P304-31(d) >
Indicates duplicate customers

< P304.1-2(d) >
Indicates duplicate customers

< P304.1-41(c) >
Revenues include billed Fuel Clause revenues of $13,295,610 for total Ultimate Customers.

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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	City of Ada	RQ	390	1369	3840	
2	City of Anoka	RQ	420	37701	37701	
3	City of Arlington	RQ	421	2806	2806	
4	City of Brownton	RQ	422	860	860	
5	City of Buffalo	RQ	423	9777	10108	
6	City of Chaska	RQ	424	28430	30194	
7	City of East Grand Forks	RQ	387	7167	21007	
8	City of Fairfax	RQ	400	618	2234	
9	City of Kasota	RQ	426	697	697	
10	City of Kasson	RQ	427	3592	3592	
11	City of Kenyon	RQ	394	2653	2653	
12	City of LeSueur	RQ	392	13184	13184	
13	City of Madelia	RQ	397	5176	5176	
14	City of Melrose	RQ	401	7574	13088	

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.
5,498	$67,905	$121,192	$1,331	$190,428	1
218,304	3,954,124	4,776,492	101,197	8,831,813	2
15,248	293,935	333,626	25,943	653,504	3
4,756	90,223	104,079	8,632	202,934	4
56,410	984,662	1,245,379	1,999	2,232,040	5
167,816	2,981,686	3,707,031	83,695	6,772,412	6
41,031	439,912	904,271	1,999	1,346,182	7
3,454	62,052	76,157	1,999	140,208	8
3,093	64,487	68,284	5,610	138,381	9
19,044	361,784	420,522	22,259	804,565	10
13,534	267,262	298,880	1,999	568,141	11
83,409	1,382,737	1,825,003	42,529	3,250,269	12
30,422	521,375	671,817	1,999	1,195,191	13
52,595	762,728	1,161,300	1,999	1,926,027	14

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 North St. Paul	RQ	429	13346	13346	
2	City of Olivia	RQ	388	754	4792	
3	City of Shakopee	RQ	431	22537	22537	
4	City of Sioux Falls	RQ	413	3831	10856	
5	City of Winthrop	RQ	433	2728	2728	
6	Northern States Power Co. (WI)	RQ	154	NA	NA	
7	Unbilled Revenue					
8	SUBTOTAL-RQ			*	*	
9	Interstate Power Co	*	417	NA	NA	NA
10	IA-IL Gas & Elec Co	*	417	NA	NA	NA
11	IES Utilities	*	417	NA	NA	NA
12	Kansas City Power & Light	*	417	NA	NA	NA
13	Lincoln Elec System	*	417	NA	NA	NA
14	Midwest Power System	*	417	NA	NA	NA

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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.
71,624	$1,399,746	$1,567,133	$35,949	$3,002,828	1
4,863	79,153	106,401	2,604	188,158	2
135,894	2,363,724	2,973,369	196,486	5,533,579	3
25,609	385,581	565,282	1,999	952,862	4
15,706	286,148	343,639	23,690	653,477	5
5,199,022			174,275,463	* 174,275,463	6
21,924		845,359		845,359	7
6,189,256	16,749,224	22,115,216	* 174,839,381	213,703,821	8
6,155		73,691		73,691	9
20,703		541,836		541,836	10
28,163		511,254		511,254	11
302,131		4,243,032		4,243,032	12
6,725		90,931		90,931	13
20,133		317,542		317,542	14

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	Madison Gas & Electric	*	359	NA	NA	NA
2	Minnesota Power Company	*	417	NA	NA	NA
3	Missouri Basin	*	417	NA	NA	NA
4	Montana-Dakota	*	417	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	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
99,877	$1,091,666	$1,715,414		$2,807,080	1
31,841		493,576		493,576	2
14,607		647,918		647,918	3
3,525		42,896		42,896	4
1,040		13,931		13,931	5
60,431		976,547		976,547	6
18,778	198,765	388,930		587,695	7
3,060		50,134		50,134	8
130,253	880,000	2,839,707		3,719,707	9
13,808		240,065		240,065	10
25,201		426,129		426,129	11
201,192		3,029,746		3,029,746	12
687		14,213		14,213	13
1,090,650	361,875	16,843,528		17,205,403	14

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	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	Basin Electric Coop	*	417	NA	NA	NA
7	Coop Power Association	*	417	NA	NA	NA
8	Dairyland Power Coop	*	417	NA	NA	NA
9	Hutchinson Utilities	*	434	NA	NA	NA
10	Minnkota Power Coop	*	417	NA	NA	NA
11	Manitoba Hydro	*	359	NA	NA	NA
12	United Power Association	*	417	NA	NA	NA
13	Western Area Power Admin	*	446	NA	NA	NA
14	City of Delano	*	470	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.
18,025		$225,313		$225,313	1
422,923		6,565,187		6,565,187	2
362,997		5,065,459		5,065,459	3
1,293,866		21,723,657		21,723,657	4
605,472	123,750	8,063,885		8,187,635	5
161		7,385		7,385	6
4,997		83,630		83,630	7
20,113		334,239		334,239	8
30		951		951	9
45,440		845,533		845,533	10
39,425		470,803		470,803	11
52,924	850,000	1,251,544		2,101,544	12
36,506		454,307		454,307	13
26,925		586,404		586,404	14

Next Page is 320

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

SALES FOR RESALE (Account 447)

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

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

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

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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 Janesville	*	470	NA	NA	NA
2	City of Lake Crystal	*	470	NA	NA	NA
3	City of Glencoe	*	470	NA	NA	NA
4	City of Mountain Lake	*	470	NA	NA	NA
5	City of Truman	*	470	NA	NA	NA
6	City of New Ulm	*	398	NA	NA	NA
7	City of Sleepy Eye	*	393	NA	NA	NA
8	City of Blue Earth	*	485	NA	NA	NA
9	City of East Grand Forks	*	476	NA	NA	NA
10	SUBTOTAL-NON-RQ					
11	TOTAL					
12						
13						
14						

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.

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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.
9,492		$203,479		$203,479	1
13,332		290,794		290,794	2
66,526		1,416,010		1,416,010	3
10,929		245,618		245,618	4
12,821		296,057		296,057	5
133,701	721,948	2,380,392		3,102,340	6
30,293	90,368	554,300		644,668	7
7,985	6,000	197,609		203,609	8
10,388	92,505	216,064		308,569	9
5,304,231	4,416,877	84,979,640	0	89,396,517	10
* 11,493,487	21,166,101	107,094,856	174,839,381	* 303,100,338	11
					12
					13
					14

< P310.1-8(d) >

15 Minute Integration

< P310.1-8(e) >

15 Minute Integration

< P310.1-9(b) >

OS - Economy, Emergency, Schedule M

< P310.1-10(b) >

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

< P310.1-11(b) >

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

< P310.1-12(b) >

OS - Scheduled Outage, Term

< P310.1-13(b) >

OS - Schedule M, Scheduled Outage

< P310.1-14(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P310.2-1(b) >

OS - Economy, General Purpose, System Power

< P310.2-2(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P310.2-3(b) >

OS - Schedule M, Operating Reserve, Scheduled Outage

< P310.2-4(b) >

OS - Economy, Schedule M, Scheduled Outage

< P310.2-5(b) >

OS - Economy, Schedule M

< P310.2-6(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P310.2-7(b) >

OS - Peaking, System Power, Supplemental Power

< P310.2-8(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P310.2-9(b) >

OS - Supplemental Power, System Power

< P310.2-10(b) >

OS - Economy, Emergency, Schedule M, Term

< P310.2-11(b) >

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

< P310.2-12(b) >

OS - Scheduled Outage, Term

< P310.2-13(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P310.2-14(b) >

OS - Excess, Participation Power, Term

< P310.3-1(b) >

OS - Supplemental Power

< P310.3-2(b) >

OS - Economy, General Purpose, General Purpose - Neg., Supplemental Power

< P310.3-3(b) >

OS - Economy, General Purpose, Schedule M, Spinning Reserve, General Purpose Neg., Supplemental Power, Firm

< P310.3-4(b) >

OS - Economy, General Purpose, General Purpose - Neg., Reserve, Supplemental Power

< P310.3-5(b) >

OS - Economy, General Purpose, Short Term, Supplemental Power

< P310.3-6(b) >

OS - Emergency

< P310.3-7(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P310.3-8(b) >

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

< P310.3-9(b) >

OS - Schedule M

< P310.3-10(b) >

OS - Economy, Interruptible Replacement, Schedule M, Participation Power

< P310.3-11(b) >

OS - Operational Control, Scheduled Outage

< P310.3-12(b) >

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

< P310.3-13(b) >

OS - Breakdown, Economy, Schedule M

< P310.3-14(b) >

OS - Economy

< P310.4-1(b) >

OS - Economy

< P310.4-2(b) >

OS - Economy

< P310.4-3(b) >

OS - Economy

< P310.4-4(b) >

OS - Economy

< P310.4-5(b) >

OS - Economy

< P310.4-6(b) >

OS - Firm, Short-term

< P310.4-7(b) >

OS - Peaking, Short-term

< P310.4-8(b) >

OS - Peaking, Supplemental

< P310.4-9(b) >

OS - Base Load

< P311.1-6(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 12 of Notes to the Financial Statements).

< P311.1-8(j) >

Includes Fuel Clause Adjustment, Customer Charge, and reimbursement to NSP-Wisconsin for production and transmission costs shared under the Interchange Agreement.

< P311.4-11(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 12 of Notes to the Financial Statements).

< P311.4-11(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 12 of Notes to the Financial Statements).

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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	$8,906,083	$8,903,359
5	(501) Fuel	254,008,117	258,483,278
6	(502) Steam Expenses	18,047,398	15,567,795
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred--Cr.		
9	(505) Electric Expenses	4,564,417	4,302,626
10	(506) Miscellaneous Steam Power Expenses	19,151,482	20,918,664
11	(507) Rents	63,610	19,015
12	(509) Allowance		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	$304,741,107	$308,194,737
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	$5,913,792	$5,553,157
16	(511) Maintenance of Structures	3,010,837	2,505,822
17	(512) Maintenance of Boiler Plant	29,019,317	20,343,960
18	(513) Maintenance of Electric Plant	9,369,852	7,018,952
19	(514) Maintenance of Miscellaneous Steam Plant	3,915,875	3,511,743
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	$51,229,673	$38,933,634
21	TOTAL Power Production Expenses--Steam Power (Enter Total of lines 13 and 20)	$355,970,780	$347,128,371
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	$22,926,406	$28,040,150
25	(518) Fuel	61,209,618	52,518,597
26	(519) Coolants and Water	316,008	135,472
27	(520) Steam Expenses	18,393,840	18,693,691
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred--Cr.		
30	(523) Electric Expenses	6,776,450	7,393,344
31	(524) Miscellaneous Nuclear Power Expenses	38,812,796	41,867,356
32	(525) Rents	238,026	36,610
33	TOTAL Operation (Enter Total of lines 24 thru 32)	$148,673,144	$148,685,220
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	$7,887,973	$10,327,591
36	(529) Maintenance of Structures	1,615,416	1,284,648
37	(530) Maintenance of Reactor Plant Equipment	11,812,489	8,274,531
38	(531) Maintenance of Electric Plant	6,136,255	5,841,925
39	(532) Maintenance of Miscellaneous Nuclear Plant	5,925,390	7,807,429
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	$33,377,523	$33,536,124
41	TOTAL Power Production Expenses--Nuclear Power (Enter total of lines 33 and 40)	$182,050,667	$182,221,344
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	$101,970	$78,412
45	(536) Water for power	117,115	108,114
46	(537) Hydraulic Expenses	44,289	59,059
47	(538) Electric Expenses	54,243	54,526
48	(539) Miscellaneous Hydraulic Power Generation Expenses	128,349	147,877
49	(540) Rents	363	1,000
50	TOTAL Operation (Enter Total of lines 44 thru 49)	$446,329	$448,988

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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	$50,409	$43,761
54	(542) Maintenance of Structures	14,005	7,826
55	(543) Maintenance of Reservoirs, Dams, and Waterways	10,458	13,890
56	(544) Maintenance of Electric Plant	35,804	54,908
57	(545) Maintenance of Miscellaneous Hydraulic Plant	8,425	9,648
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	$119,101	$130,033
59	TOTAL Power Production Expenses-Hydraulic Power(Enter total of lines 50 and 58)	$565,430	$579,021
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	$195,007	$162,759
63	(547) Fuel	1,722,377	1,065,124
64	(548) Generation Expenses	218,101	189,611
65	(549) Miscellaneous Other Power Generation Expenses	378,357	402,355
66	(550) Rents	6,912	6,912
67	TOTAL Operation (Enter Total of lines 62 thru 66)	$2,520,754	$1,826,761
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	$201,718	$210,141
70	(552) Maintenance of Structures	44,294	(17,071)
71	(553) Maintenance of Generating and Electric Plant	503,655	692,627
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	84,622	(187,677)
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	$834,289	$698,020
74	TOTAL Power Production Expenses--Other Power (Enter Total of lines 67 and 73)	$3,355,043	$2,524,781
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	$249,885,983	$208,845,457
77	(556) System Control and Load Dispatching	2,390,358	2,407,592
78	(557) Other Expenses	* 49,719,498	48,358,824
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$301,995,839	$259,611,873
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$843,937,759	$792,065,390
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$2,944,676	$2,286,844
84	(561) Load Dispatching	3,683,072	3,549,977
85	(562) Station Expenses	(198,173)	1,232,648
86	(563) Overhead Lines Expenses	697,003	580,206
87	(564) Underground Lines Expenses	94,889	65,278
88	(565) Transmission of Electricity by Others	2,971,023	2,113,245
89	(566) Miscellaneous Transmission Expenses	* 26,314,751	27,294,742
90	(567) Rents	420,791	408,428
91	TOTAL Operation (Enter Total of lines 83 thru 90)	$36,928,032	$37,531,368
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$372,454	$357,744
94	(569) Maintenance of Structures	24,234	19,786
95	(570) Maintenance of Station Equipment	5,597,135	6,382,237
96	(571) Maintenance of Overhead Lines	4,430,802	2,425,145
97	(572) Maintenance of Underground Lines	52,358	11,002
98	(573) Maintenance of Miscellaneous Transmission Plant	1,297,360	0
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$11,774,343	$9,195,914
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$48,702,375	$46,727,282
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	$4,499,251	$1,927,317

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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	$2,604,753	$3,893,547
106	(582) Station Expenses	2,434,682	2,410,280
107	(583) Overhead Line Expenses	4,519,819	3,978,936
108	(584) Underground Line Expenses	4,286,646	3,496,093
109	(585) Street Lighting and Signal System Expenses	407,712	556,568
110	(586) Meter Expenses	2,892,087	2,924,350
111	(587) Customer Installations Expenses	671,274	659,357
112	(588) Miscellaneous Expenses	13,186,707	13,738,582
113	(589) Rents	753,105	576,302
114	TOTAL Operation (Enter Total of lines 103 thru 113)	$36,256,036	$34,161,332
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	$581,218	$1,257,826
117	(591) Maintenance of Structures	285,016	364,159
118	(592) Maintenance of Station Equipment	6,823,974	7,011,694
119	(593) Maintenance of Overhead Lines	23,900,350	27,725,459
120	(594) Maintenance of Underground Lines	5,075,214	4,874,823
121	(595) Maintenance of Line Transformers	852,916	975,843
122	(596) Maintenance of Street Lighting and Signal Systems	1,598,570	1,831,800
123	(597) Maintenance of Meters	116,662	231,709
124	(598) Maintenance of Miscellaneous Distribution Plant	82,467	209,595
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	$39,316,387	$44,482,908
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	$75,572,423	$78,644,240
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	$1,559,533	$1,853,741
130	(902) Meter Reading Expenses	8,625,633	8,295,361
131	(903) Customer Records and Collection Expenses	14,964,854	12,658,244
132	(904) Uncollectible Accounts	5,521,379	4,482,517
133	(905) Miscellaneous Customer Accounts Expenses	3,805,842	3,826,286
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	$34,477,241	$31,116,149
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	$12,888	$158,491
138	(908) Customer Assistance Expenses	24,555,997	23,417,560
139	(909) Information and Instructional Expenses	966,791	943,716
140	(910) Miscellaneous Customer Service and Information Expenses	7,052,490	6,821,226
141	TOTAL Cust. Service and Informational Exp.(Enter Total of lines 137 thru 140)	$32,588,166	$31,340,993
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		$17,930
145	(912) Demonstrating and Selling Expenses	1,446,140	1,108,564
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses	84,535	21,114
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	$1,530,675	$1,147,608
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	$48,059,121	$47,328,457
152	(921) Office Supplies and Expenses	21,346,277	24,988,390
153	(Less) (922) Administrative Expenses Transferred--Credit	5,499,288	5,551,425

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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	$2,421,054	$1,720,119
156	(924) Property Insurance	8,479,584	9,278,114
157	(925) Injuries and Damages	18,208,098	6,644,413
158	(926) Employee Pensions and Benefits	54,150,626	50,114,595
159	(927) Franchise Requirements	21,059	27,605
160	(928) Regulatory Commission Expenses	2,921,581	3,945,222
161	(929) Duplicate Charges--Cr.	(1,000,573)	(970,067)
162	(930.1) General Advertising Expenses	1,116,108	1,145,137
163	(903.2) Miscellaneous General Expenses	10,419,439	10,472,421
164	(931) Rents	77,123	14,949
165	TOTAL Operation (Enter Total of lines 151 Thru 164)	$160,720,209	$149,157,930
166	Maintenance		
167	(935) Maintenance of General Plant	$175,689	$451,984
168	TOTAL Administrative and General Expenses (Enter total of lines 165 thru 167)	$160,895,898	$149,609,914
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126,134,141,148 and 168)	$1,197,704,537	$1,130,651,576

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)	12/31/94	
2. Total Regular Full-Time Employees		5,249
3. Total Part-Time and Temporary Employees		716
4. Total Employees	*	5,965

< P321-78(b) >

Includes $39,259,898 of Fixed Costs and $8,344,931 of Variable Costs reimbursed to Northern States Power Co. (Wisconsin), a subsidiary company, for production costs shared through an Interchange Agreement.

< P321-89(b) >

Includes $25,897,779 of Fixed Costs reimbursed to Nothern States Power Company (Wisconsin), a subsidiary company, for transmission costs shared through an Interchange Agreement.

< P323 >

Estimated number of employees attributed to electric department from joint functions - 1,037.

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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 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 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)	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	Hutchinson Utilities	*	434	NA	NA	NA
5	Interstate Power Co	*	417	NA	NA	NA
6	Interstate Power Co	*	417	NA	NA	NA
7	IES Utilities	*	417	NA	NA	NA
8	IA IL Gas & Electric Co	*	417	NA	NA	NA
9	Kansas City Power & Light	*	417	NA	NA	NA
10	Lincoln Electric Sys	*	417	NA	NA	NA
11	Manitoba Hydro	*	359	NA	NA	NA
12	Midwest Power Systems	*	417	NA	NA	NA
13	Minnesota Power	*	417	NA	NA	NA
14	Minnkota Power Coop	*	417	NA	NA	NA

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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 deliverd 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 date 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.
27,925				$531,500		$531,500	1
91,352				1,245,434		1,245,434	2
48,343				748,157		748,157	3
9				270		270	4
2,952				92,421		92,421	5
		27,954				0	6
5,532				111,470		111,470	7
108,025				2,607,404		2,607,404	8
132,132				2,978,545		2,978,545	9
45,875				1,183,634		1,183,634	10
6,378,793			68,448,681	98,662,286		167,110,967	11
5,208				107,250		107,250	12
142,369			1,716,486	2,469,132		4,185,618	13
586,369			16,073,207	6,324,221		22,397,428	14

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 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)	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	Muscatine Power & Water	*	417	NA	NA	NA
5	Nebraska Public Power Dist	*	417	NA	NA	NA
6	Northwestern Public Service	*	417	NA	NA	NA
7	Northwestern WI Electric	*	417	NA	NA	NA
8	Omaha Public Power Dist	*	417	NA	NA	NA
9	Otter Tail Power	*	417	NA	NA	NA
10	Rochester Public Util	*	* NA	NA	NA	NA
11	Southern MN Municipal Power	*	417	NA	NA	NA
12	Union Electric	*	321	NA	NA	NA
13	United Power Assoc	*	417	NA	NA	NA
14	United Power Assoc	*	417	NA	NA	NA

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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
4. footnote for each adjustment.
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
5. provided.
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 deliverd 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 date 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.
53,563				$777,874		$777,874	1
	7,292					0	2
40,774				765,648		765,648	3
9,942				143,509		143,509	4
50,785				874,656		874,656	5
4,682				87,812		87,812	6
50				7,519		7,519	7
18,572				694,477		694,477	8
52,149				930,887		930,887	9
10,703			630,000	310,878		940,878	10
32,608				469,351		469,351	11
242,487				5,423,897		5,423,897	12
61,312			564,960	720,917		1,285,877	13
	33,324						14

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 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	Western Area Power Admin	*	446	NA	NA	NA
2	WI Electric Power Co	*	319	NA	NA	NA
3	WI Power & Light	*	410	NA	NA	NA
4	WI Public Power Inc Sys	*	447	NA	NA	NA
5	WI Public Service Corp	*	346	NA	NA	NA
6	City of Blue Earth	*	485	NA	NA	NA
7	American Resource Recovery	*	IPP	NA	NA	NA
8	Barron County Waste	*	IPP	NA	NA	NA
9	Windpower Partners 1993 LP	*	IPP	NA	NA	NA
10	Byllesby Dam	*	IPP	NA	NA	NA
11	Chippewa Reservoir Power	*	IPP	NA	NA	NA
12	Cypress Silver Bay Power Co	*	IPP	NA	NA	NA
13	Eau Galle Renew Energy Co	*	IPP	NA	NA	NA
14	Ford Motor Co	*	IPP	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.

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 deliverd 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.

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	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.
268,107				$4,725,058		$4,725,058	1
51,916				1,069,634		1,069,634	2
77,630				1,478,468		1,478,468	3
3,899				58,636		58,636	4
63				4,536		4,536	5
2,013				19,140		19,140	6
389				10,693		10,693	7
16				405		405	8
37,367				2,108,336		2,108,336	9
13,826			412,315	266,400		678,715	10
3,878			465,594	250,185		715,779	11
103,939			6,135,120	1,853,765		7,988,885	12
859				53,676		53,676	13
12,465				166,991		166,991	14

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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:

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Hastings Lock & Dam	*	IPP	NA	NA	NA
2	Hennepin Energy Resource Recov	*	IPP	NA	NA	NA
3	Minnesota Methane	*	IPP	NA	NA	NA
4	Neshkoro Power Association	*	IPP	NA	NA	NA
5	Actacon-Rapidan	*	IPP	NA	NA	NA
6	St. Cloud Hydro	*	IPP	NA	NA	NA
7	Alfred Jessen	*	IPP	NA	NA	NA
8	Lester Vandenberg	*	IPP	NA	NA	NA
9	Steven Schwen	*	IPP	NA	NA	NA
10	John Youngdahl	*	IPP	NA	NA	NA
11	Wilbert Redmund	*	IPP	NA	NA	NA
12	District Energy	*	Co-Gen	NA	NA	NA
13	Municipal Energy Agency of Nebraska	*	Co-Gen	NA	NA	NA
14	Northern States Power Co (WI)	RQ	154	NA	NA	NA

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 deliverd 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 date 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.

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	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.
21,532			$692,595	$245,873		$938,468	1
215,740			8,096,534	2,547,049		10,643,583	2
14,474			179,983	213,112		393,095	3
2,801			77,328	62,488		139,816	4
35,344			507,840	445,494		953,334	5
55,078			1,391,113	634,776		2,025,889	6
13				872		872	7
4				283		283	8
2				149		149	9
13				821		821	10
1				38		38	11
573				8,139		8,139	12
2				60		60	13
403,029					47,604,829	* 47,604,829	14

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Mid-Continent Area Power Pool	*	MAPP	NA	NA	NA
2	TOTAL					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 deliverd 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 date 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.
		102,532					1
9,477,484	40,616	130,486	105,391,756	144,494,226	47,604,829 *	297,490,811	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14

< P326-1(b) >

OS - Schedule M, Scheduled Outage

< P326-2(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P326-3(b) >

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

< P326-4(b) >

OS - Emergency

< P326-5(b) >

OS - Emergency, Schedule M

< P326-6(b) >

EX - Compensation as a result of the difference between the point of metering and point of system interconnection on the Wilmarth-Winnebago line.

< P326-7(b) >

OS - Economy, Emergency, Schedule M

< P326-8(b) >

OS - Economy, Emergency, Excess, Schedule M, Term

< P326-9(b) >

OS - Scheduled Outage, Term

< P326-10(b) >

OS - Economy, Schedule M

< P326-11(b) >

OS - Operational Control, Peaking, Participation Power, Seasonal Diversity, Scheduled Outage, Tertiary; Includes an accrual for disagreement on Payment to Manitoba

< P326-12(b) >

OS - Emergency, Schedule M, Scheduled Outage

< P326-13(b) >

OS - Economy, Emergency, Firm, Schedule M, Operating Reserve, Scheduled Outage

< P326-14(b) >

OS - Coyote, Economy, Emergency, Schedule M, Operational Control, Participation Power, Base Load

< P326.1-1(b) >

OS - Schedule M, Scheduled Outage

< P326.1-2(b) >

EX - Compensation for losses at Splitrock.

< P326.1-3(b) >

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

< P326.1-4(b) >

OS - Economy, Emergency, Schedule M

< P326.1-5(b) >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< P326.1-6(b) >

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

< P326.1-7(b) >

OS - Operational Control

< P326.1-8(b) >

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

< P326.1-9(b) >

OS - Economy, Emergency, Schedule M, System Power

< P326.1-10(b) >

OS - Emergency, Firm, Schedule M, Operational Control, Participation Power, Scheduled Outage; it was not necessary for NSP to file this contract since NSP's only transactions with them were purchases.

< P326.1-10(c) >

NA - Emergency, Firm, Schedule M, Operational Control, Participation Power, Scheduled Outage; it was not necessary for NSP to file this contract since NSP's only transactions with them were purchases.

< P326.1-11(b) >

OS - Economy, Emergency, Schedule M

< P326.1-12(b) >

OS - Emergency, Excess, Term

< P326.1-13(b) >

OS - Economy, Emergency, Schedule M, Operational Control, Participation Power

< P326.1-14(b) >

EX - Due to Joint Transmission Network Agreement.

< P326.2-1(b) >

OS - Economy, Emergency, Schedule M, Replacement

< P326.2-2(b) >

OS - Economy, General Purpose

< P326.2-3(b) >

OS - General Purpose

< P326.2-4(b) >

OS - Economy, Emergency, Excess, Schedule M

< P326.2-5(b) >

OS - General Purpose

< P326.2-6(b) >

OS - Dump Energy

< P326.2-7(b) >

OS - Base Load

< P326.2-8(b) >

OS - Base Load

< P326.2-9(b) >

OS - Base Load

< P326.2-10(b) >

OS - Base Load

< P326.2-11(b) >

OS - Firm

< P326.2-12(b) >

OS - Base Load

< P326.2-13(b) >

OS - Base Load

< P326.2-14(b) >

OS - Excess

< P326.3-1(b) >

OS - Base Load, Excess

< P326.3-2(b) >

OS - Base Load

< P326.3-3(b) >

OS - Base Load

< P326.3-4(b) >

OS - Base Load

< P326.3-5(b) >

OS - Base Load, Excess, Peaking

< P326.3-6(b) >

OS - Base Load, Excess, High On-Peak

< P326.3-7(b) >

OS - Windmill Energy

< P326.3-8(b) >

OS - Windmill Energy

< P326.3-9(b) >

OS - Windmill Energy

< P326.3-10(b) >

OS - Windmill Energy

< P326.3-11(b) >

OS - Windmill Energy

< P326.3-12(b) >

OS - Steam Driven Energy

< P326.3-13(b) >

OS - Emergency

< P326.4-1(b) >

EX - Due to MAPP Loss Repayment Procedure.

< P327.3-14(m) >

Total dollars will not match page 321, line 75, due to differences in accounting classification of dollars associated with the interchange agreement between the Minnesota and Wisconsin companies (see Note 12 of the Notes to Financial Statements).

< P327.4-2(m) >

Total dollars will not match page 321, line 75, due to differences in accounting classification of dollars associated with the interchange agreement between the Minnesota and Wisconsin companies (see Note 12 of the Notes to Financial Statements).

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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	Dairyland Power Coop	Western Area Power Administration	Dairyland Power Coop	LF
6	Midwest Power Systems	Midwest Power Systems	St Joseph Power & Light	LF
7	So MN Municipal Power Agency	Sherco 3 Power Plant	Various	LF
8	City of Mountain Lake	West Area Power Administration	Interstate Power	LF
9	Wis Public Power Inc System-West	Minnesota Power	Various	LF
10	Wis Public Power Inc System-East	Minnesota Power	Various	LF
11	NW Wisconsin Electric Power	NW Wisconsin Electric Power	Dairyland Power Coop	LF
12	City of Anoka	NSP	Anoka	LF
13	City of Shakopee	NSP	Shakopee	LF
14	University of North Dakota	Western Area Power Administration	University of North Dakota	LF
15	City of Hillsboro	Western Area Power Administration	Hillsboro	LF
16	Wisconsin Public Service	Otter Tail Power	Wisconsin Public Service	*
17	City of Ada	Western Area Power Administration	Ada	LF

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	
342	Various	Various		2,367,922	2,314,684	1
457	* Sioux Fls Intercon	* Luverne Interconn	29			2
464	Missouri Basin Inter	Blue Earth	*	40,255	39,312	3
NSP Tarrif Vol 1	Minnesota Power	Wis P & L Interconn		79,775	77,849	4
407	Various	Various		28,121	28,121	5
351	Neal Power Plant	St Joseph P & L				6
415	Sherco 3	Various		637,005	* 582,720	7
453	* Sioux Fls Intercon	* Luverne Interconn	1			8
466	Minnesota Power	Wis Pub Pwr Inc	*	255,986	255,986	9
465	Minnesota Power	WEP, WPS, WPL	62			10
451	Black Brook Hydro	NSP-DPC Pnt of Intcn		1,578	1,353	11
420	Crooked Lake Sub	Crooked Lake Sub				12
431	Blue Lake Substation	Blue Lake Substation				13
440	NSP-WAPA Interconnec	University of ND	8	45,343	44,280	14
414	NSP-WAPA Interconnec	Hillsboro	5	13,645	13,325	15
NSP Tarriff Vol 1	Otter Tail Power	Wis Public Service		101,649	99,122	16
390	NSP-WAPA Interconnec	Ada	3	14,239	13,905	17

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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.
		* $44,664	$44,664	1
			*	2
69,345			69,345	3
	155,698		155,698	4
	28,121		28,121	5
		326,484	326,484	6
		* 107,156	107,156	7
10,272			10,272	8
724,715		* 27,852	752,567	9
915,740			915,740	10
	5,254		5,254	11
		* 63,000	63,000	12
		* 20,000	20,000	13
17,702		* 113,364	131,066	14
75,194			75,194	15
	198,244		198,244	16
42,254		* 13,360	55,614	17

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	City of East Grand Forks	Western Area Power Administration	East Grand Forks	LF
2	City of Fairfax	Western Area Power Administration	Fairfax	LF
3	City of Granite Falls	West Area Pwr Adm, Miss Basin	Granite Falls	LF
4	City of Marshall	West Area Pwr Adm, Heartland	Marshall	LF
5	City of Melrose	Western Area Power Administration	Melrose	LF
6	City of Olivia	Western Area Power Administration	Olivia	LF
7	City of St James	West Area Pwr Adm, Miss Basin	St James	LF
8	City of Sauk Centre	West Area Pwr Adm, Miss Basin	Sauk Centre	LF
9	City of Sleepy Eye	Western Area Power Administration	Sleepy Eye	LF
10	City of Sioux Falls	Western Area Power Administration	Sioux Falls	LF
11	SD State Penitentiary	Western Area Power Administration	SD State Penitentiary	LF
12	City of Springfield	Western A [illegible] Power Administration	Interstate Power	LF
13	City of Windom	Western Area Power Administration	Interstate Power	LF
14	Missouri Basin Municipal Power Agency	Western Area Power Administration	Interstate Power	LF
15	Heartland Consumers Power Dist	Heartland Consumers Power Dist	United Power Association	LF
16	Wisconsin Electric Power Co	Basin Electric Power Coop	Wisconsin Electric Power	*
17	Wisconsin Electric Power Co	Otter Tail Power	Wisconsin Electric Power	*

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 Megatthours Received (i)	Megatthours Delivered (j)	Line No.
483	NSP-WAPA Interconnec	East Grand Forks		76,237	74,450	1
400	NSP-WAPA Interconnec	Fairfax	2	8,827	8,620	2
436	*	Granite Falls		7,011	6,847	3
403	NSP-WAPA Interconnec	Marshall	*	129,923	126,878	4
401	NSP-WAPA Interconnec	Melrose	6	36,494	35,639	5
338	NSP-WAPA Interconnec	Olivia	5	23,224	22,680	6
412	*	St James	*	34,061	33,263	7
449	*	Sauk Centre	*	25,165	24,575	8
393	NSP-WAPA Interconnec	Sleepy Eye	3	8,671	8,468	9
484	NSP-WAPA Interconnec	Sioux Falls	8	45,501	44,435	10
385	NSP-WAPA Interconnec	SD State Pen	1	3,372	3,293	11
454	* Sioux Fls Intercon	* Luverne Interconn	1	5,553	5,553	12
455	* Sioux Fls Intercon	* Luverne Interconn	9	35,478	35,478	13
456	* Sioux Fls Intercon	* Luverne Interconn	53	281,321	281,321	14
471	Marshall	United Power Assoc	13	80	80	15
NSP Tarrif Vol 1	Basin Elec	Wis Elec Power	98	523,012	502,908	16
NSP Tarrif Vol 1	Otter Tail Power	Wis Elec Power	40	127,240	124,188	17

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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.
		* $53,572	$53,572	1
27,723			27,723	2
4,452		* 27,470	31,922	3
808,608			808,608	4
88,531			88,531	5
71,974			71,974	6
179,539		* 28,056	207,595	7
126,274			126,274	8
37,486			37,486	9
838		* 38,604	39,442	10
1,312		* 1,505	2,817	11
11,136		* 981	12,117	12
68,496		* 5,728	74,224	13
416,052			416,052	14
11,053	80		11,133	15
1,578,935			1,578,935	16
386,300			386,300	17

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Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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	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	Western Area Power Administration	Wisconsin Electric Power	*
4	Interstate Power Co	Minnesota Power	Interstate Power	*
5	Interstate Power Co	United Power Association	Interstate Power	*
6	TOTAL			
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 Tarrif Vol 1	Otter Tail Power	Wis Elec Power		8,100	7,901	1
NSP Tarrif Vol 1	Minnesota Power	Wis Elec Power		2,660	2,592	2
NSP Tarrif Vol 1	Western Area Pwr Adm	Wis Elec Power		878	850	3
NSP Tarrif Vol 1	Minnesota Power	Interstate Power	54	197,214	192,479	4
NSP Tarrif Vol 1	United Power Assoc	Interstate Power	98	351,645	343,205	5
				5,517,185	5,356,360	6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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.
	$15,802		$15,802	1
	5,184		5,184	2
	1,700		1,700	3
572,439			572,439	4
993,720			993,720	5
7,240,090	410,083	871,796	8,521,969	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17

< P328-4(d) >
DS - Interruptible Service

< P328-16(d) >
DS - Interruptible Service

< P328.1-16(d) >
DS - Reserved Service

< P328.1-17(d) >
DS - Reserved Service

< P328.2-1(d) >
DS - Interruptible Service

< P328.2-2(d) >
DS - Interruptible Service

< P328.2-3(d) >
DS - Interruptible Service

< P328.2-4(d) >
DS - Reserved Service

< P328.2-5(d) >
DS - Reserved Service

< P329-2(f) >
NSP-WAPA 345kv

< P329-2(g) >
NSP-IPW 161kv

< P329-3(h) >
4.395kw = 1/94-12/94; .6kw = 5/94-10/94

< P329-7(j) >
This number is in dispute pending resolution of Docket #EL91-43-000.

< P329-8(f) >
NSP-WAPA 345kv

< P329-8(g) >
NSP-IPW 161kv

< P329-9(h) >
48.4kw = 1/94-4/94; 51.3kw = estimated 5/94-12/94

< P329.1-3(f) >
NSP-WAPA interconnection, and Missouri Basin interconnections.

< P329.1-4(h) >
54.8kw = 1/94-4/94; 54.72kw = 5/94-12/94

< P329.1-7(f) >
NSP-WAPA interconnection, and Missouri Basin interconnections.

< P329.1-7(h) >
12.3kw = 1/94-4/94; 12.0kw = 5/94-12/94

< P329.1-8(f) >
NSP-WAPA interconnection, and Missouri Basin interconnections.

< P329.1-8(h) >
8.3kw = 1/94-4/94; 8.1kw = 5/94-12/94

< P329.1-12(f) >
NSP-WAPA 345kv

< P329.1-12(g) >
NSP-IPW 161kv

< P329.1-13(f) >
NSP-WAPA 345kv

< P329.1-13(g) >
NSP-IPW 161kv

< P329.1-14(f) >
NSP-WAPA 345kv

< P329.1-14(g) >
NSP-IPW 161kv

< P330-1(m) >

Settlement on the basis of $.018 mills for KWH's delivered to CPA loads from CPA-NSP integrated transmission system, plus $250 per month for host control area costs.

< P330-2(n) >

CPA's compensation to NSP is provided under FERC Rate Schedule no. 342.

< P330-7(m) >

Generation Control and Transmission Control-Transmission Agreement with SMMPA.

< P330-9(m) >

Non-firm power; meter service charge.

< P330-12(m) >

Facilities charge.

< P330-13(m) >

Facilities charge.

< P330-14(m) >

Facilities charge; transformation service @.0007/Kwh.

< P330-17(m) >

Facilities charge.

< P330.1-1(m) >

Facilities charge.

< P330.1-3(m) >

Facilities charge.

< P330.1-7(m) >

Facilities charge.

< P330.1-10(m) >

Facilities charge.

< P330.1-11(m) >

Facilities charge.

< P330.1-12(m) >

Transmission Losses.

< P330.1-13(m) >

Transmission Losses.

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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: Megawatthours Received (b)	TRANSFER OF ENERGY: Megawatthours 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	419,388	415,236	$219,659			$219,659
2	Redwood Electric Coop	2,421	2,421	* 30,786			30,786
3	Stearns Coop Elec Assn	425	421		* 3,223		3,223
4	McLeod Elec Coop	1,573	1,505	* 1,622			1,622
5	Minnkota Power Coop	19,968	19,968		* 21,368		21,368
6	NSP-WAPA-SD State Pen	281,092	271,566	* 1,645,300			1,645,300
7	NW Wis Elec Power	140,837	131,624		* 524,188		524,188
8	Minnesota Power					* 524,757	524,757
9	North Central Power	1	1		* 120		120
10	Otter Tail Power	1,729,001	1,698,313	0	0	0	0
11	WAPA-Mallard Logan Line	184,721	181,942	0	0	0	0
12							
13	Total	2,779,427	2,722,997	1,897,367	[illegible]48,899	524,757	2,971,023
14							
15							
16							

< P332-2(d)) >

Settled on a basis of \$.72/Kw plus basic monthly charge \$2,008.50.

< P332-3(e)) >

Settled on a basis of \$.001/Kwh; plus fixed monthly charge \$233.00.

< P332-4(d)) >

Settled on a basis of \$.39/Kw.

< P332-5(e)) >

Settled on a basis of \$.001/Kwh.

< P332-6(d)) >

WAPA transmission service @ \$12.65/62,000 Kw. This number also includes an accrual for a probable increase in the transmission rate.

< P332-7(e)) >

Transmission Service @ \$3.70/Mwh Jan-Apr; \$3.67/Mwh May-Dec

< P332-8(f)) >

Phase Angle Regulatory Transformer Cost Sharing Agreement.

< P332-9(e)) >

NCP generation when NWEC suffered a transmission outage.

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)(ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	$539,627
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	6,380,594
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	2,693,042
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	36,545
8	Company Postage	55,888
9	Security	18,784
10	Brokers Expense	167,384
11	Audio & Video	50,215
12	Air Express	12,089
13	Facility (The State Theater)	9,299
14	Other Items	27,897
15		
16	Directors Fees and Expenses:	
17	H Lyman Bretting	31,680
18	David A Christensen	34,812
19	W John Driscoll	34,812
20	N Bud Grossman	18,257
21	Dale L Haakenstad	31,680
22	Allen F Jacobson	30,606
23	Richard M Kovacevich	31,680
24	Douglas W Leatherdale	32,575
25	Donald W McCarthy	9,128
26	John E Pearson	33,739
27	W G Phillips	18,256
28	G M Pieschel	33,918
29	Margaret R Preska	32,575
30	D B Reinhart	18,257
31	A Patricia Sampson	31,680
32	E M Theisen	1,074
33		
34	Other Expenses (2 items)	3,346
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	$10,419,439

Name of Respondent Northern States Power Company	This Report Is: (1) [x]An Original (2) [ ]A Resubmission	Date of Report (Mo,Da,Yr) 05/09/95	Year of Report Dec. 31, 1994

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 service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average 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		$150,771		$150,771
2	Steam Product Plant	55,848,650			55,848,650
3	Nuclear Production Plant	88,935,041			88,935,041
4	Hydraulic Production Plant—Conventional	198,871		38,668	237,539
5	Hydraulic Production Plant—Pumped Storage				
6	Other Production Plant	3,463,927			3,463,927
7	Transmission Plant	15,842,798			15,842,798
8	Distribution Plant	46,282,329			46,282,329
9	General Plant	7,180,993			7,180,993
10	Common Plant--Electric	3,155,863	4,198,280		7,354,143
11	TOTAL	$220,908,472	$4,349,051	$38,668	$225,296,191

B. Basis for Amortization Charges

ACCOUNT 404

The total computer software amortization of $4,198,280 is based on 60 months (1.67%) on an average basis of $20,949,501. New Software has been capitalized and certain old software has been fully amortized.

ACCOUNT 405

The annual $38,668 amortization charge for Mill-Powers is based on a plant balance of $1,235,057.41 and a life of 32 years, beginning Jan. 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.

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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	311	283,376		(15.00%)			18.00
13	312	908,463		0			16.80
14	314	222,842		0			16.00
15	315	141,385		0			17.70
16	316	58,803		0			16.10
17	SUBTOTAL	1,614,869					
18							
19							
20							
21	321 *	274,299					14.30
22	321 *	6,603					14.20
23	322 *	558,422					14.50
24	322 *	15,174					14.60
25	323 *	122,731					14.30
26	323 *	15,251					13.70
27	324 *	192,462					13.90
28	324 *	2,661					14.30
29	325 *	133,313					14.30
30	SUBTOTAL	1,320,916					
31							
32							
33							
34	331	442		(10.00%)			6.10
35	332	2,724		(15.00%)			6.10
36	333	1,140		5.00%			6.10
37	334	303		5.00%			6.10
38	335	42		5.00%			6.10
39	SUBTOTAL	4,651					
40							
41							
42							
43	341	2,758		0			9.80
44	342	3,676		0			8.80
45	344	81,458		0.40%			15.40
46	345	4,961		0			7.70
47	346	473		0			4.40
48	SUBTOTAL	93,326					
49							
50							
51							
52	352	8,710					32.40
53	353	235,700					31.40
54	354	92,420					29.60
55	355	94,970					23.80
56	356	116,820					29.20
57	357	4,784					42.60
58	358	4,343					29.40
59	SUBTOTAL	557,747					
60							
61							
62							
63							

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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)
64	361	19,364					33.80
65	362	219,915					30.30
66	364	142,903					21.80
67	365	167,162					25.00
68	366	76,708					34.00
69	367	357,352					26.00
70	368	212,242					24.50
71	368	261					17.30
72	368	10,151					11.20
73	369	47,464					21.80
74	369	81,066					25.10
75	370	87,218					19.80
76	371	910					3.50
77	371	12,426					3.60
78	371	379					4.10
79	372	178					19.50
80	372	1					8.70
81	373	21,874					8.80
82	373	16					6.00
83	SUBTOTAL	1,457,590					
84							
85	390	42,095					36.50
86	390	931					33.70
87	391	719					3.90
88	391	3,837					13.00
89	391	3,792					3.60
90	392 *						0.80
91	392 *						3.70
92	392 *						3.60
93	392 *						6.50
94	393	1,969					13.80
95	394	1,006					9.40
96	394	3,935					11.00
97	394	13,127					11.50
98	394	618					2.40
99	395	6,375					14.60
100	396	2					2.70
101	396 *						5.10
102	396	11					3.40
103	397	35,254					4.40
104	397	99					3.00
105	397	1,048					3.90
106	397	61					7.30
107	397	49					2.70
108	398	459					10.20
109	SUBTOTAL	115,387					
110	TOTAL	5,164,486					
111							
112							
113							
114							
115	*						

< P338 >

DESCRIPTION SECTION C

Line 21 Nuclear - Structures & Improvements
Line 23 Nuclear - Reactor Plant Equipment
Line 22,24,26,28,86,104 - Leased
Line 70 Line Transformers
Line 71 Line Transformers - Trailers
Line 72 Line Capacitors
Line 73 Overhead Services
Line 74 Unerground Services
Line 76 Leased Property on Customers' Premises
Line 77 Leased Property on Customers' Premises
Line 78 Leased Property on Customers' Premises
Line 79 Leased Property on Customers' Premises
Line 80 Loaned Property on Customers' Premises
Line 81 Street Lighting and Signal Systems
Line 82 Street Lighting Transformers in Reserve
Line 85 Structures & Improvements
Line 87 Office Furniture & Equipment
Line 95 Tools, Shop, & Garage Equipment
Line 96 Tools, Shop, & Garage Equipment
Line 97 Other Tools & Work Equipment
Line 98 Hand Held Meters
Line 100 Power Operated Equipment - Mobile (Licensed)
Line 102 Power Operated Equipment - Other
Line 103 Communication Equipment
Line 104 Communication Equipment - Leased to Others

Line 90-93,101 - Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1)

	Charged to Clearing Accounts	Depreciable Plant Base
Line 90 Cars	6,627	785
Line 91 Vans & Light Trucks	430,036	5,445
Line 92 Licensed Trailers	188,547	2,410
Line 93 Heavy Trucks	1,734,640	25,114
Line 101 Trenchers, Loaders, Cranes & Other Power Operated Equipment	409,779	4,914
TOTAL	2,769,629	38,668

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 during the past year.

(3) Line 21-29 (d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning Costs are recovered using an internal and external sinking fund calculation.

(4) P337(c),(e) & (f) are not applicable.
P338(c),(d),(e) & (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)	*	4,525,156
8	Total-426.1 (see page 340A)		4,525,156
9			
10			
11	Life Insurance (Subaccount 426.2)		
12	Wealth-Op - Cash Surrender Value Earnings		(3,667,564)
13	Wealth-Op - Premium Expense		2,996,714
14	Officer Survivor Benefits-Premium Expense		520,412
15	Officer Survivor Benefits-Cash Surrender Value Earn		(419,670)
16	Total 426.2		(570,108)
17			
18			
19	Penalties (Subaccount 426.3)		16,978
20	Total-426.3		16,978
21			
22			
23	(Subaccount 426.4)		
24	Expenditures for Certain Civic & Political Activity	*	2,592,186
25	Total-426.4 (see page 340A)		2,592,186
26			
27			
28	Other Deductions (Subaccount 426.5)		
29	Social and Service Club Dues (see page 340A)	*	74,325
30	Employee Corporate Expenses		154,830
31	Settlements of Employment Complaints		1,011,763
32	Regulatory Reserve		4,567,966
33	Miscellaneous - Donations		154,760
34	Miscellaneous		44,635
35	Total-426.5		6,008,279
36			
37			
38	Interest on Debt to Associated Companies (Acct 430)		
39	Cormorant at an average effective rate of 4.38%		12,631
40	Total-430		12,631
41			

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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	Other Interest Expense (Account 431)	
2	Commercial Paper	9,342,326
3	Customer Deposits	77,278
4	Tax Assessments Past Due	759,500
5	Coal Mine Reclamation	254,877
6	Interest on 1993 MN Electric Rate Refund	428,861
7	Working Capital Fees	(134,685)
8	Net Interest Inc & Exp on Wealth-Op Def Comp Plan	416,318
9	Estimated Westmoreland Coal Production Tax Liab.	753,695
10	Estimated Liability for Severence Tax Credit Incent	323,942
11	Miscellaneous	44,575
12	Total-431	12,266,687
13		
14		
15		
16		
17		
18		
19		
20		
21		
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< P340-7(b) >

ANALYSIS OF DONATIONS - subaccount 426.1

United Way - 57 Items	$1,222,364
Civic/Cultural - 63 Items	386,185
Health & Human Services - 174 Items	1,374,643
Education - 216 Items	558,533
Community Improvement - 93 Items	584,500
Miscellaneous (Regional Grants) - 679 Items	398,931
TOTAL	$4,525,156

< P340-24(b) >

EXPENDITURE FOR CERTAIN CIVIC, POLITICAL, AND RELATED ACTIVITIES (Account 426.4)

Prairie Island Dry Cask Storage	$1,655,725
Salaries & Expenses of Various Employees during 1994 Session of Minnesota Legislature & Committee Meetings	437,985
Salaries & Expenses of Various Employees relating to Lobbying Federal Agencies	116,729
Keystone Center Awards Dinner	5,000
Congressional Staff Tour - Yucca Mountain	3,168
Utility Working Group	12,000
Edison Electric Institute	52,041
Minnesota Utility Investors Group - Membership/Expenses	223,164
Professional Services - Miscellaneous	74,555
Various Miscellaneous Items	11,819
TOTAL	$2,592,186

< P340-29(b) >

ANALYSIS OF SOCIAL AND SERVICE CLUB DUES (See Other Deductions - Subaccount 426.5 on Page 340)

Decathlon Athletic Club	$1,863
Exchange Club	2,615
Fargo Country Club	1,905
Grand Forks Country Club	1,651
Kiwanis Club	2,934
Lions Club	1,969
Makato Golf Club	1,746
Midland Hills Country Club	2,944
Minikahda Club	4,173
Minneapolis Athletic Club	8,553
Minneapolis Club	9,620
Minneapolis Rotary Club	11,760
Minnesota Club	8,435
Minot Country Club	1,300
National Democratic Club	1,286
St. Cloud Rotary Club	2,543
Town & Country Club	3,067
Winona Country Club	2,120
Ten miscellaneous other clubs	3,841
TOTAL	$74,325

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

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 to Date (d)	Deferred in Account 186 at Beginning of year (e)
1	Expenses incurred preparing filings and				
2	attending conferences and hearings.				
3					
4	Minnesota Docket Nos.				
5	E-002/GR-92-1185 (Rate)		165,953	165,953	
6	E-002/RP-93-630 (Resource Plan)		259,400	259,400	
7	GR-92-1186 (Rate)		270,481	270,481	
8					
9					
10					
11					
12	Assessments by the State of Minnesota,				
13	Minnesota Public Service Commission and the				
14	Department of Public Service for rate and				
15	other expenses in accordance with provision	1,367,482		1,367,482	
16	of the 1974 utility regulation law.	280,493		280,493	
17					
18					
19					
20					
21	State of South Dakota Public Utilities				
22	Commission special hearing fund assessment.	104,784		104,784	
23					
24					
25					
26					
27	Expenses incurred preparing filing and				
28	attending conferences and hearings in				
29	connection with various FERC electric rate				
30	filings.				
31	ER93-385-000		160,255	160,255	
32	ER94-1090 & ER94-1113	194,702		194,702	
33	FERC Annual Assessment	560,745		560,745	
34					
35					
36					
37					
38	Various Miscellaneous Regulatory Expenses				
39	Electric		108,259	108,259	
40	Gas		20,314	20,314	
41					
42					
43					
44					
45					
46	TOTAL	$2,508,206	$984,662	$3,492,868	

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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. The totals of columns (e), (i), (k), and (l) must agree with the totals shown at the bottom of page 233 for Account 186.

5. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.

6. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO			Deferred to Account 186	Contra Account	Amount	Deferred in Account 186, End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
							4
Electric	E928	165,953					5
Electric	E928	259,400					6
Gas	G928	270,481					7
							8
							9
							10
							11
							12
							13
							14
Electric	E928	1,367,482					15
Gas	G928	280,493					16
							17
							18
							19
							20
							21
Electric	E928	104,784					22
							23
							24
							25
							26
							27
							28
							29
							30
Electric	E928	160,255					31
Electric	E928	194,702					32
Electric	E928	560,745					33
							34
							35
							36
							37
							38
Electric	E928	108,259					39
Gas	G928	20,314					40
							41
							42
							43
							44
							45
[redacted]		$3,492,868		[redacted]			46

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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	
2	(1) Generation	
3	A Hydropower	
4	None	
5	B Fossil Fuel - Steam	
6	Coal Qlty Impacts on Plant Perform	
7	Black dog #2 FBC Optimization	
8	Misc (6)	
9		
10	C Internal Combustion or Gas Turbine	
11	None	
12	D Nuclear	
13	None	
14	E Unconventional Generation	
15	Fuel Cells Users Group	
16	Fuel Cell Demonstration	
17	F Siting & Heat Rejection	
18	Dakotas Project	
19		
20	(2) System Planning Engineering & Operatn	
21	Utility Data Network Evaluation	
22	Misc (3)	
23	(3) Transmission	
24	A Overhead	
25	Misc (3)	
26	B Underground	
27	Underground Trans Cable Temp Mntr	
28	(4) Distribution	
29	Manufactured Wood Poles	
30	Nova - Distribution Automation	
31	Stray Voltage	
32	(5) Environment - Other than Equipment	
33	Misc (2)	
34		
35		
36		
37		
38		

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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
9,718		930.2	9,718		6
29,738		930.2	29,738		7
1,269		930.2	1,269		8
					9
					10
					11
					12
					13
					14
10,624		930.2	10,624		15
12,497		930.2	12,497		16
					17
372		930.2	372		18
					19
					20
10,151		930.2	10,151		21
12,709		930.2	12,709		22
					23
					24
656		930.2	656		25
					26
484		930.2	484		27
					28
21,833		930.2	21,833		29
104,249		930.2	104,249		30
353		930.2	353		31
					32
1,172		930.2	1,172		33
					34
					35
					36
					37
					38

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	(6) Other	
4	A Alternative Energy	
5	Photovoltaic Demonstration	
6	Buffalo Ridge Wind Project	
7	Photovoltaics	
8	North Dakota Wind Resource Assessmnt	
9	Util Renew Resource Assoc	
10	Misc (6)	
11	B By-Product Utilization	
12	Planning Activities RDF	
13	UND Advisory Council	
14	Misc (5)	
15	C Conservation	
16	Alternative Energy Development Plan	
17	D Load Management	
18	Ice Slurry/District Cooling	
19	Thermal Storage in Ice Slurry	
20	Natural Gas Air Condition Study	
21	Misc (4)	
22	E Load Research	
23	Load Research Large C&I Cust Resrch	
24	Load Research Small C&I Customers	
25	Residential Load Resrch Monitr Prog	
26	F Metering	
27	Jurisdictional Metering	
28	G Research - General	
29	Research - General	
30	EPRI Projects Review & Evaluations	
31	Misc (4)	
32		
33		
34		
35	SUBTOTAL Cost Incurred - Internal	
36		
37		
38		

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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
7,339		930.2	7,339		5
8,517		930.2	8,517		6
6,521		930.2	6,521		7
5,192		930.2	5,192		8
6,902		930.2	6,902		9
9,868		930.2	9,868		10
					11
8,591		930.2	8,591		12
5,107		930.2	5,107		13
4,814		930.2	4,814		14
					15
38		930.2	38		16
					17
(260,034)		107.0	(260,034)		18
49,163		930.2	49,163		19
(32,030)		930.2	(32,030)		20
4,011		930.2	4,011		21
					22
11,621		930.2	11,621		23
6,353		930.2	6,353		24
5,171		930.2	5,171		25
					26
9,058		930.2	9,058		27
					28
116,149		930.2	116,149		29
33,375		930.2	33,375		30
(1,377)		930.2	(1,377)		31
					32
					33
					34
220,174	0		220,174	0	35
					36
					37
					38

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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	(B) Electric RD&D Performed Externally	
2	(1) Research Support to EPRI	
3	EPRI Membership	
4	EPRI Advisory Group Participation	
5	(2) Research Support to Edison Electric	
6	None	
7	(3) Research Support to Nuclear Power Grp	
8	None	
9	(4) Research Support to Others	
10	By-Products Utilization - Wis	
11	Misc (2)	
12		
13		
14		
15	SUBTOTAL Cost Incurred - External	
16		
17		
18		
19		
20	GRAND TOTAL	
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute

(3) Research Support to Nuclear Power Groups

(4) Research Support to Others (Classify)

(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $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
					2
	5,822,572	930.2	5,822,572		3
	20,609	930.2	20,609		4
					5
					6
					7
					8
					9
	7,295	930.2	7,295		10
	5	930.2	5		11
					12
					13
					14
0	5,850,481		5,850,481	0	15
					16
					17
					18
					19
	6,070,655		6,070,655		20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	$84,399,303		
4	Transmission	3,514,252		
5	Distribution	23,359,896		
6	Customer Accounts	18,098,239		
7	Customer Service and Informational	4,956,387		
8	Sales	639,245		
9	Administrative and General	51,577,977		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	$186,545,299		
11	Maintenance			
12	Production	41,874,799		
13	Transmission	1,227,021		
14	Distribution	13,291,761		
15	Administrative and General	22,977		
16	TOTAL Maint. (Total of lines 12 thru 15)	$56,416,558		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	$126,274,102		
19	Transmission (Enter Total of lines 4 and 13)	$4,741,273		
20	Distribution (Enter Total of lines 5 and 14)	$36,651,657		
21	Customer Accounts (Transcribe from line 6)	18,098,239		
22	Customer Service and Informational(Transcribe from line 7)	4,956,387		
23	Sales (Transcribe from line 8)	639,245		
24	Administrative and General (Enter Total of lines 9 and 15)	$51,600,954		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	$242,961,857	$3,321,380	$246,283,237
26	Gas			
27	Operation			
28	Production--Manufactured Gas	244,267		
29	Production--Nat. Gas(Including Expl. and Dev.)			
30	Other Gas Supply	614,537		
31	Storage, LNG Terminaling and Processing	417,949		
32	Transmission	622,571		
33	Distribution	8,181,277		
34	Customer Accounts	3,740,947		
35	Customer Service and Informational	916,671		
36	Sales	572,115		
37	Administrative and General	6,150,532		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	$21,460,866		
39	Maintenance			
40	Production--Manufactured Gas	120,437		
41	Production--Natural Gas			
42	Other Gas Supply	369		
43	Storage, LNG Terminaling and Processing	305,196		
44	Transmission	76,768		
45	Distribution	3,425,433		
46	Administrative and General	60,034		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	$3,988,237		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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)	$364,704		
50	Production--Natural Gas (Including Expl. and Dev.) (Total of lines 29 and 41)			
51	Other Gas Supply (Enter Total of lines 30 and 42)	$614,906		
52	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)	$723,145		
53	Transmission (Lines 32 and 44)	$699,339		
54	Distribution (Lines 33 and 45)	$11,606,710		
55	Customer Accounts (Line 34)	3,740,947		
56	Customer Service and Informational (Line 35)	916,671		
57	Sales (Line 36)	572,115		
58	Administrative and General (Lines 37 and 46)	$6,210,566		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	$25,449,103	$522,769	$25,971,872
60	Other Utility Departments			
61	Operation and Maintenance	0	0	0
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	$268,410,960	$3,844,149	$272,255,109
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	48,887,266	3,516,452	52,403,718
66	Gas Plant	7,063,885	337,583	7,401,468
67	Other	0	0	0
68	TOTAL Construction (Total of lines 65 thru 67)	$55,951,151	$3,854,035	$59,805,186
69	Plant Removal (By Utility Departments)			
70	Electric Plant	2,550,722	204,555	2,755,277
71	Gas Plant	159,081	17,308	176,389
72	Other	0	0	0
73	TOTAL Plant Removal (Total of lines 70 thru 72)	$2,709,803	$221,863	$2,931,666
74	Other Accounts (Specify):			
75	Non Operating and Non Utility Income Accounts	2,380,182	24,192	2,404,374
76	Accounts Receivable	4,751,450	273,979	5,025,429
77	Materials & Supplies	6,631,139	904,034	7,535,173
78	Temporary Facilities	99,211	6,029	105,240
79	Other Deferred Debits	6,149,534	247,677	6,397,211
80	Conservation Programs	4,409,027		4,409,027
81	Hazardous Waste Disposal	316,449		316,449
82	Prepaids	45,943		45,943
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	$24,782,935	$1,455,911	$26,238,846
96	TOTAL SALARIES AND WAGES	$351,854,849	$9,375,958	$361,230,807

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 - See Page 356.A

2 - See Page 356.A

3 - See Page 356.A

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 1994.
920 to 935 Incl. 408	Administrative and General expenses and tax other than income taxes were allocated based on the 1994 labor allocator.
403,404	Common Depreciation Expense has been allocated to various utilities on the basis of a study that considers customers and labor.
	Pension costs on labor affecting operating acocunts were charged to Account 926.

4 - The use of common utility plant classification was recommended by commission letter dated 8-14-69.

COMMON UTILTIY PLANT IN SERVICE		ALLOCATED TO UTILITY DEPARTMENTS	
ACCOUNT	COST AT DEC 31, 1994	ELECTRIC	GAS
(a)	(b)	(c)	(d)
INTANGIBLE PLANT			
301 Organization	$100,608	$91,000	$9,608
303 Computer Software	39,914,138	36,102,338	3,811,800
Total Intangible Plant	$40,014,746	$36,193,338	$3,821,408
GENERAL PLANT			
389 Land and Land Rights	$1,896,648	$1,389,847	$506,801
390 Structures and Improvements	39,764,944	31,578,236	8,186,708
391 Office furniture and equipment	71,221,932	62,807,963	8,413,969
392 Transportation equipment	298,050	199,391	98,659
393 Stores equipment	947,448	593,860	353,588
394 Tools, shop and garage equipment	2,936,910	1,994,989	941,921
395 Laboratory equipment	35,983	31,980	4,003
396 Power operated equipment	6,446	4,339	2,107
397 Communication equipment	14,731,166	11,389,934	3,341,232
398 Miscellaneous equipment	641,215	567,241	109,974
Total General Plant	$131,516,743	$110,577,781	$21,958,962
Total Common Utility Plant - In Service	$172,531,488	$146,751,118	$25,780,370
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	$3,582,773	$378,280
COMMON UTILITY PLANT CONSTUCTION WORK IN PROGRESS			
GENERAL PLANT	$31,338,424	$28,105,926	$3,232,498
COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION			
GENERAL PLANT	$90,547,859	$79,232,651	$11,315,208

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.

COMMON UTILITY PLANT EXPENSES		ALLOCATED TO UTILITY DEPARTMENTS	
ACCOUNT	TOTAL	ELECTRIC	GAS
(a)	(b)	(c)	(d)
CUSTOMER ACCOUNTS EXPENSES			
903 Customer record and collection expenses	$26,769	$22,672	$4,097
Total Customer Accounts Expenses	$26,769	$22,672	$4,097
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
909 Informational and instructional advertising expenses	$86,600	$73,893	$12,707
910 Misc. customer service and informational expenses	17,449	14,779	2,670
Total Customer Service and Informational Expenses	$104,049	$88,672	$15,377
ADMINISTRATIVE AND GENERAL EXPENSES			
920 Administrative and general expenses	$25,960,695	$23,516,349	$2,444,346
921 Office supplies and expenses	14,517,140	13,145,081	1,372,059
922 Administrative expenses transferred - Cr.	(2,117,286)	(1,918,347)	(198,939)
923 Outside services employed	1,745,720	1,581,695	164,025
924 Property insurance	114,618	103,897	10,721
925 Injuries and damages	2,780,917	2,519,573	261,344
926 Employee pensions and benefits	10,958,399	9,929,343	1,029,056
930.1 Miscellaneous general expenses	23,760	21,522	2,238
930.2 Miscellaneous general expenses	2,145,619	1,935,826	209,793
931 Rents	5,966	5,405	561
935 Maintenance of general plant	218	198	20
Total Administrative and General Expenses	$56,135,766	$50,840,542	$5,295,224
403 Depreciation Expense	$3,899,868	$3,155,863	$744,005
404 Amortization of limited term common plant	$4,641,548	$4,198,280	$443,268
408.1 Taxes other than income taxes	$2,031,469	$1,840,592	$190,877
Total Common Utility Plant Expenses	$66,839,469	$60,146,621	$6,692,848

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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	20,157,898
4	Nuclear	12,224,760
5	Hydro--Conventional	89,187
6	Hydro--Pumped Storage	0
7	Other	25,710
8	(Less) Energy for Pumping	0
9	Net Generation (Enter Total of lines 3 thru 8)	32,497,555
10	Purchases	9,477,484
11	Power Exchanges:	
12	Received	40,616
13	Delivered	130,486
14	Net Exchanges (Line 12 minus line 13)	(89,870)
15	Transmission For Other (Wheeling)	
16	Received	5,517,185
17	Delivered	5,356,360
18	Net Transmission for Other (Line 16 minus Line 17)	160,825
19	Transmission By Other Losses	(52,278)
20	TOTAL (Enter Total of Lines 9, 10, 14, 18 and 19)	41,993,716

Line No.	Item (a)	Megawatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	28,241,562
23	Requirements Sales for Resale (See instruction 4, page 311.)	6,189,256
24	Non-Requirements Sales For Resale (See Instruction 4, page 311.)	5,304,231
25	Energy Furnished Without Charge	1,144
26	Energy Used by the Company (Electric Department Only, Excluding Station Use)	* 59,307
27	Total Energy Losses	2,198,216
28	TOTAL (Enter Total of Lines 22 Thru 27) (MUST EQUAL LINE 20)	41,993,716

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)	Day of Month (e)	Hour (f)
29	January	3,547,782	418,208	4,486	17	19
30	February	2,942,380	214,206	4,391	7	19
31	March	3,089,209	318,419	3,955	1	9
32	April	3,020,531	445,647	3,958	18	14
33	May	3,401,883	622,583	4,414	23	17
34	June	3,477,505	356,194	5,930	14	17
35	July	3,610,573	477,790	5,658	19	16
36	August	3,664,074	490,373	5,685	25	15
37	September	3,346,666	514,625	5,462	14	17
38	October	3,350,714	583,114	4,156	17	14
39	November	3,205,842	478,262	4,279	29	18
40	December	3,362,330	384,810	4,455	19	18
41	TOTAL	40,019,489	* 5,304,231			

< P401 >

1) Certain parts of the system of the respondent are connected or interconnected with the systems or parts of the systems of the Northern States Power Company (Wisconsin), which is a subsidiary of Northern States Power Compnay (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	335
February	215
March	235
April	262
May	274
June	713
July	151
August	235
September	230
October	100
November	500
December	495
	500

3) Non-integrated systems

Name of System: Fargo-Grand Forks North Dakota System

Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales For Resale & Associated Losses (c)	MONTHLY PEAK Megawatt (d)	Day of Month (e)	Hour (f)
January	199,652		347	18	9
February	167,927		349	7	9
March	148,604		273	8	9
April	125,872		248	5	9
May	121,293		236	23	16
June	121,900		253	23	14
July	123,790		243	11	14
August	126,538		264	3	14
September	119,292		262	6	16
October	129,223		239	24	8
November	144,349		281	30	8
December	169,876		315	6	8
Total	1,698,316				

Name of System: Minot North Dakota System

Month	Total Monthly Energy		Megawatt	Day of Month	Hour
January	27,721		48	5	18
February	20,868		50	2	17
March	23,007		46	30	11
April	20,640		40	22	12
May	21,271		46	17	17
June	21,499		48	24	15
July	23,762		52	18	16
August	24,205		57	15	17
September	22,043		56	6	17
October	22,166		44	18	20
November	22,888		45	28	19
December	25,834		50	6	18
Total	275,911				

< P401-26(b) >

Includes 19,651 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.

< P401-(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	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as show on line 21.
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)	504.20			46.00		
6	Net Peak Demand on Plant -- MW (60 mintues)						
7	Plant Hours Connected to Load	7,957			2,865		
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	436			47		
10	When Limited by Condenser Water	463			47		
11	Average Number of Employees	120			21		
12	Net Generation, Exclusive of Plant Use --KWh	1,371,353,000			89,530,000		
13	Cost of Plant						
14	Land and Land Rights	952,692			20,492		
15	Structures and Improvements	23,701,285			3,748,832		
16	Equipment Costs	154,395,659			9,028,291		
17	Total Cost	$179,049,636			$12,797,615		
18	Cost per KW of Installed Capacity (line 5)	355.1163			278.2090		
19	Production Expenses:						
20	Operation Supervision and Engineering	1,040,970			324,966		
21	Fuel	18,090,192			1,422,016		
22	Coolants and Water (Nuclear Plants Only)						
23	Steam Expenses	2,257,502			244,317		
24	Steam From Other Sources						
25	Steam Transferred (Cr.)						
26	Electric Expenses	1,058,071			169,939		
27	Misc. Steam (or Nuclear) Power Expenses	2,346,680			221,944		
28	Rents	28,037					
29	Maintenance Supervision and Engineering	1,050,890			122,612		
30	Maintenance of Structures	411,854			65,435		
31	Maintenance of Boiler (Or Reactor) Plant	5,222,535			132,872		
32	Maintenance of Electric Plant	2,246,641			93,961		
33	Maintenance Misc. Steam (or Nuclear) Plant	687,027			29,054		
34	Total Production Expenses	$34,440,399			$2,827,116		
35	Expenses per Net KWh	$0.0251			$0.0316		
36	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Coal	Gas	Oil	Coal	Gas	Oil
37	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	Tons	MCF	Bbls	Tons	MCF	Bbls
38	Quantity (Units) of Fuel Burned	892,990	220,747	2	63,559	25,747	290
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if unclear)	8,688	1,015	142,857	9,664	1,016	137,997
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$18.210	$2.440	$27.350	$18.630	$2.180	$24.430
41	Average Cost of Fuel per Unit Burned	$19.650	$2.450	$32.940	$21.360	$2.190	$26.630
42	Avg. Cost of Fuel Burned per Million Btu	$1.130	$2.420	$5.070	$1.110	$2.160	$4.590
43	Avg. Cost of Fuel Burned per KWh Net Gen		$13.190			$15.880	
44	Average Btu per KWh Net Generation		11.480			14.030	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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 26 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type,fuel used, fuel enrichment type and quantity for the report period,and other physical and operating characteristics of plant.

Plant Name: 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	396.80	381.90	5
			6
7,836	6,715	8,294	7
			8
22	263	372	9
22	262	366	10
27	123	136	11
117,047,000	1,056,634,000	1,745,906,000	12
			13
$368,322	$528,150	$397,485	14
4,953,938	18,570,196	25,819,890	15
28,544,039	62,714,118	133,113,292	16
$33,866,299	$81,812,464	$159,330,667	17
1,354.6520	206.1806	417.2052	18
			19
305,833	1,043,100	942,948	20
1,609,069	15,498,523	22,043,219	21
			22
736,427	2,556,143	3,498,009	23
			24
			25
420,329	374,120	307,331	26
338,344	2,087,910	2,250,750	27
10,954	11,091		28
310,026	738,219	853,394	29
44,125	356,041	730,210	30
1,527,852	2,451,780	3,665,130	31
385,336	440,585	559,157	32
384,654	120,770	470,204	33
$6,0[illegible],949	$25,678,282	$35,320,352	34
$0.0519	$0.0243	$0.0202	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
RDF	Gas		Coal	Gas	Oil	Coal	Gas	Oil	36
Tons	MCF		Tons	MCF	Bbls	Tons	MCF	Bbls	37
193,530	15,387		695,71[illegible]	229,897	463	1,048,296	37,510	3,045	38
5,517	1,016		8,563	1,043	139,591	8,740	1,015	139,495	39
$3.780	$3.290		$20.440	$1.940	$18.000	$19.150	$2.710	$23.600	40
$8.050	$3.310		$21.620	$1.950	$18.780	$20.860	$2.720	$24.660	41
$0.730	$3.260		$1.260	$1.860	$3.200	$1.190	$2.680	$4.210	42
	$13.750			$14.670			$12.630		43
	18.380			11.510			10.530		44

Next Page is 406

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.
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 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as show on line 21.
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 mintues)		
7	Plant Hours Connected to Load	5	41
8	Net Continuous Plant Capability (Megawatts)	15	
9	When Not Limited by Condenser Water		64
10	When Limited by Condenser Water		64
11	Average Number of Employees	0	4
12	Net Generation, Exclusive of Plant Use --KWh	(132,000)	(54,000)
13	Cost of Plant		
14	Land and Land Rights	19,415	289,140
15	Structures and Improvements	117,231	3,535,234
16	Equipment Costs	3,285,329	11,930,671
17	Total Cost	$3,421,975	$15,755,045
18	Cost per KW of Installed Capacity (line 5)	105.9435	210.0673
19	Production Expenses:		
20	Operation Supervision and Engineering	21,516	80,751
21	Fuel	18,638	84,830
22	Coolants and Water (Nuclear Plants Only)		
23	Steam Expenses		42,958
24	Steam From Other Sources		
25	Steam Transferred (Cr.)		
26	Electric Expenses	3,913	58,664
27	Misc. Steam (or Nuclear) Power Expenses	6,901	262,286
28	Rents	6,696	
29	Maintenance Supervision and Engineering	25,898	60,655
30	Maintenance of Structures		15,517
31	Maintenance of Boiler (Or Reactor) Plant		23,613
32	Maintenance of Electric Plant	17,151	19,460
33	Maintenance Misc. Steam (or Nuclear) Plant	2,448	14,965
34	Total Production Expenses	$103,161	$663,699
35	Expenses per Net KWh	($0.7815)	($12.2907)
36	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Gas	Gas
37	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	MCF	MCF
38	Quantity (Units) of Fuel Burned	9,867	26,480
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if unclear)	1,000	976
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$1.890	$2.730
41	Average Cost of Fuel per Unit Burned	$1.890	$3.200
42	Avg. Cost of Fuel Burned per Million Btu	$1.890	$3.280
43	Avg. Cost of Fuel Burned per KWh Net Gen		
44	Average Btu per KWh Net Generation		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

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 26 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas -turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type,fuel used, fuel enrichment type and quantity for the report period,and other physical and operating characteristics of plant.

Plant Name: 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			1,947.40			226.80			5
									6
7,744			8,758			63			7
						190			8
581			2,295						9
567			2,295						10
102			458			5			11
3,561,659,000			12,109,222,000			1,493,000			12
									13
$666,505			$5,255,027			$190,323			14
20,769,288			180,405,850			847,172			15
101,748,709			808,452,665			19,830,219			16
$123,184,502			$994,113,542			$20,867,714			17
205.8565			510.4825			92.0093			18
									19
813,866			4,047,059			67,781			20
35,209,845			159,065,940			249,380			21
									22
2,097,542			5,877,679						23
									24
									25
515,990			1,250,137			81,458			26
2,138,017			8,720,032			148,333			27
13,528									28
848,275			1,603,951			73,349			29
257,794			1,082,104			33,045			30
3,170,437			11,109,610						31
692,373			4,391,752			132,269			32
521,666			1,338,381			63,184			33
$46,279,333			$198,486,645			$848,799			34
$0.0130			$0.0164			$0.5685			35
Coal	Gas	Wood	Coal		Oil			Oil	36
Tons	MCF	Tons	Tons		Bbls			Bbls	37
1,867,566	18,610	16,478	7,205,848		15,369			11,236	38
9,123	1,025	8,207	8,596		139,903			138,003	39
$17.390	$1.980	$13.690	$21.380		$23.790			$22.190	40
$18.450	$2.000	$13.860	$22.020		$25.560			$22.190	41
$1.010	$1.950	$0.840	$1.280		$4.350			$3.830	42
	$9.750				$13.140			$167.030	43
	9.650				10.240			43.620	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	05/09/95	Dec. 31, 1994

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 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as show on line 21.
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 mintues)				
7	Plant Hours Connected to Load	79		63	
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	2,225,000		1,061,000	
13	Cost of Plant				
14	Land and Land Rights	40,240		67,495	
15	Structures and Improvements	474,772		155,215	
16	Equipment Costs	6,280,705		7,351,477	
17	Total Cost	$6,795,717		$7,574,187	
18	Cost per KW of Installed Capacity (line 5)	94.3850		105.1970	
19	Production Expenses:				
20	Operation Supervision and Engineering	21,168		23,122	
21	Fuel	265,233		74,914	
22	Coolants and Water (Nuclear Plants Only)				
23	Steam Expenses				
24	Steam From Other Sources				
25	Steam Transferred (Cr.)				
26	Electric Expenses	4,269		7,849	
27	Misc. Steam (or Nuclear) Power Expenses	32,173		16,373	
28	Rents	96			
29	Maintenance Supervision and Engineering	4,581		31,634	
30	Maintenance of Structures			3,289	
31	Maintenance of Boiler (Or Reactor) Plant			75,179	
32	Maintenance of Electric Plant	19,078		19,321	
33	Maintenance Misc. Steam (or Nuclear) Plant	3,352			
34	Total Production Expenses	$349,950		$251,681	
35	Expenses per Net KWh	$0.1573		$0.2372	
36	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Gas	Oil	Gas	Oil
37	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	MCF	Bbls	MCF	Bbls
38	Quantity (Units) of Fuel Burned	135,434	179	30,570	286
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if unclear)	1,014	140,138	1,014	139,293
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$1.910	$33.270	$2.300	$16.090
41	Average Cost of Fuel per Unit Burned	$1.910	$33.270	$2.300	$16.090
42	Avg. Cost of Fuel Burned per Million Btu	$1.890	$5.660	$2.270	$2.750
43	Avg. Cost of Fuel Burned per KWh Net Gen		$119.210		$70.610
44	Average Btu per KWh Net Generation		62.170		30.800

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 26 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment,report each as a separate plant. However,if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit,include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development;(b)types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type,fuel used, fuel enrichment type and quantity for the report period,and other physical and operating characteristics of plant.

Plant Name: * 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
			6
7,437	140	8,694	7
	343		8
553		1,064	9
539		1,025	10
436	6	544	11
3,956,317,000	6,260,000	8,268,442,000	12
			13
$767,317	$221,371	$377,794	14
100,783,166	843,220	190,199,435	15
371,980,655	29,317,489	673,713,312	16
$473,531,138	$30,382,080	$864,290,541	17
832.5090	93.0824	728.6213	18
			19
8,962,104	58,869	13,964,140	20
19,616,583	535,667	41,593,035	21
289,064		26,944	22
11,726,977		6,666,863	23
			24
			25
1,128,842	120,330	5,647,609	26
17,461,669	169,615	21,351,127	27
238,026	120		28
2,714,233	66,086	5,173,739	29
153,126	7,796	1,462,290	30
6,438,976		5,373,513	31
1,951,352	250,182	4,184,903	32
2,602,185	(4,180)	3,323,204	33
$73,283,137	$1,204,485	$108,767,367	34
$0.0185	$0.1924	$0.0132	35
Nuclear	Oil	Nuclear	36
Grams U-235	Bbls	Grams U-235	37
326,705	23,445	826,974	38
127,680	135,960	107,359	39
	$22.850		40
$60.040	$22.850	$50.300	41
$0.470	$4.000	$0.470	42
$4.960	$85.570	$5.060	43
10.540	21.390	10.740	44

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as show on line 21.
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 mintues)				
7	Plant Hours Connected to Load	212			
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	15,326,000			
13	Cost of Plant				
14	Land and Land Rights	442,375			
15	Structures and Improvements	1,293,582			
16	Equipment Costs	65,724,862			
17	Total Cost	$67,460,819			
18	Cost per KW of Installed Capacity (line 5)	321.2420			
19	Production Expenses:				
20	Operation Supervision and Engineering	125			
21	Fuel	578,054			
22	Coolants and Water (Nuclear Plants Only)				
23	Steam Expenses				
24	Steam From Other Sources				
25	Steam Transferred (Cr.)				
26	Electric Expenses	282			
27	Misc. Steam (or Nuclear) Power Expenses	3,002			
28	Rents				
29	Maintenance Supervision and Engineering				
30	Maintenance of Structures	164			
31	Maintenance of Boiler (Or Reactor) Plant				
32	Maintenance of Electric Plant	703			
33	Maintenance Misc. Steam (or Nuclear) Plant	497			
34	Total Production Expenses	$582,827			
35	Expenses per Net KWh	$0.0380			
36	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Gas	Oil		
37	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	MCF	Bbls		
38	Quantity (Units) of Fuel Burned	107,208	12,250		
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if unclear)	1,007	141,739		
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$1.690	$32.360		
41	Average Cost of Fuel per Unit Burned	$1.690	$32.360		
42	Avg. Cost of Fuel Burned per Million Btu	$1.680	$5.440		
43	Avg. Cost of Fuel Burned per KWh Net Gen	$41.030			
44	Average Btu per KWh Net Generation	12.840			

< P403.1-col(e) >

Instruction 3 - Sherburne County Generating Plant (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 13 on Notes to the Financial Statements for further discussion.

< P403.2-col(d) >

Instruction 12 - Monticello Nuclear Generating Plant (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 BWR3 Nuclear Power Plant. Fuel material is UO2 contained in Zircaloy tube cladding. The equilibrium cycle has approximately 86 metric tons of Uranium metal with a nominal U-235 enrichment of 2.8%. The reactor is licensed to allow operation of 1670 MWT.

< P403.2-col(f) >

Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403.2)

(a) Operating and maintenance costs of the Prairie Island 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 Prairie Island Plant is a 2 loop pressurized water reactor nuclear power plant of Westinghouse design. Fuel material is UO2 contained in Zircaloy-4 and zirlo tube cladding. The equilibrium cycle has approximately 43 metric tons of Uranium metal enriched at three different levels, the average of which is 4.4 weight percent of U-235. The reactor is licensed to operate at 1650 MWT. There are two identical units at the Prairie Island site.

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	20.40	
6	Net Peak Demand on Plant-Megawatts (60 minutes)		
7	Plant Hours Connected to Load	NA	
8	Net Plant Capability (In megawatts)		
9	(a) Under the Most Favorable Oper. Conditions	20	
10	(b) Under the Most Adverse Oper. Conditions	2	
11	Average Number of Employees	0	
12	Net Generation, Exclusive of Plant Use-KWh	89,187,000	
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	1,485,068	
18	Roads, Railroads, and Bridges		
19	TOTAL Cost (Enter Total of lines 14 thru 18)	$5,298,485	
20	Cost per KW of Installed Capacity (Line 5)	$259.7297	
21	Production Expenses:		
22	Operation Supervision and Engineering	85,706	
23	Water for Power	113,815	
24	Hydraulic Expenses	57,340	
25	Electric Expenses	54,243	
26	Misc. Hydraulic Power Generation Expenses	126,821	
27	Rents	363	
28	Maintenance Supervision and Engineering	46,563	
29	Maintenance of Structures	14,005	
30	Maintenance of Reservoirs, Dams, and Waterways	8,482	
31	Maintenance of Electric Plant	29,510	
32	Maintenance of Misc. Hydraulic Plant	8,425	
33	Total Production Expenses (Total lines 22 thru 32)	$545,273	
34	Expenses per net KWh	$0.0061	

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	28.6	106,601	31,815,894
4						
5						
6	INTERNAL COMBUSTION					
7						
8	Disbursed Generation				(724)	3,198,686
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		201	636,245
20						
21						
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Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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)	Production Expenses: Operation Excl. 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
	1,757,792	1,465,460	2,978,755	RDF, Gas	228¢	3
						4
						5
						6
						7
	4,031	490	1,786	Oil	232¢	8
						9
						10
						11
						12
	8,042		12,115	Hydro		13
						14
						15
						16
						17
						18
	356		7,479	Wind		19
						20
						21
						22
						23
						24
						25
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						46

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 05/09/95	Dec. 31, 1994

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.

5. Indicate whether the type of supporting structure reported in column(e) is:(1) single pole,wood or steel;(2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f)and(g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (Indicate where other than 60 cycle,3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines, report circuit miles)		Number of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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	16.72		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	738.55	43.06	35

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
3-1192ACSR	$1,723,334	$60,108,710	$61,832,044					1
3-1192ACSR	2,328,448	16,330,332	18,658,780	79,794	490,233	0	* 570,027	2
2-795ACSR	401,465	2,382,525	2,783,990					3
2-795ACSR								4
2-795ACSR	2,224,390	9,191,243	11,415,633					5
2-954ACSR								6
2-795ACSR								7
2312ACSR								8
2312ACSR								9
2-954ACSR								10
2-795ACSR	1,539,503	4,033,144	5,572,648					11
2-795ACSR								12
2-954ACSR	882,197	4,162,509	5,044,707					13
2-954ACSR								14
2-954ACSR	187,240	10,124,835	10,312,074					15
2-795ACSR								16
2-795ACSR								17
2-795ACSR	4,875,371	12,978,573	17,853,944					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	14,275,854	15,584,737					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	8,733	3,704,319	3,713,052					34
2-954ACSR								35
	$16,170,720	$145,984,205	$162,154,925	$79,794	$490,233	0	$570,027	36

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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 (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE 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	Sherburne Co (0985)	CU Conn	345.00	345.00	Twr on 0978		7.00	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	1,071.74	183.58	70

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TRANSMISSION LINE STATISTICS (Continued)

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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	958,866	3,456,198	4,415,064					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	89,474	1,251,199	219,150	* 1,559,823	28
795ACSR	450,318	4,505,637	4,955,955					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
	$19,758,462	$175,689,312	$195,447 774	$169,268	$1,741,432	$219,150	$2,129,850	36

TRANSMISSION LINE STATISTICS

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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			1,122.80	83.24	
9	Various		69.00			1,782.01	38.66	
10	Various		34.50			67.30	0.70	
11	Various		23.00			5.55	1.20	
12	Various		115.00		Underground	6.02		
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	4,160.11	310.99	77

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

TRANSMISSION LINE STATISTICS (Continued)

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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) Land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795ACSR	$31,735	$674,935	$706,670					1
795ACSR								2
954ACSR	57,281	758,399	815,680					3
795ACSR	21,223	519,989	541,213					4
954ACSR	3,103	1,023,620	1,026,723	32,143	127,223	78	* 159,444	5
477ACSR	112,192	694,292	806,484					6
477ACSR	56,236	971,716	1,027,952	3,223	15,520	94	* 18,837	7
	10,395,481	74,548,600	84,944,080	155,174	1,260,281	179,806	* 1,595,261	8
	3,427,962	53,096,526	56,524,488	332,142	1,279,811	20,670	* 1,632,623	9
	242	984,357	984,599	5,053	6,535	213	* 11,801	10
	0	363,854	363,854	0	0	680	* 680	11
	0	8,312,659	8,312,659	94,889	52,358		* 147,247	12
	0	798,244	798,244					13
	0	34,380	34,380				0	14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	$33,863,918	$318,470,882	$352,334,800	$791,892	$4,483,160	$420,691	$5,695,743	36

< P423-2(p) >

Total expenses for all 500KV overhead transmission lines.

< P423.1-28(p) >

Total expenses for all 345KV overhead transmission lines.

< P423.2-5(p) >

Total expenses for all 230KV overhead transmission lines.

< P423.2-7(p) >

Total expenses for all 161KV overhead transmission lines.

< P423.2-8(p) >

Total expenses for all 115KV overhead transmission lines.

< P423.2-9(p) >

Total expenses for all 69KV overhead transmission lines.

< P423.2-10(p) >

Total expenses for all 34.5KV overhead transmission lines.

< P423.2-11(p) >

Total expenses for all 23KV overhead transmission lines.

< P423.2-12(p) >

Total expenses for all 115KV underground transmission lines.

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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Aldrich	Parkers Lake	0.10	Pole	10.00	2	2
2	Red Rock	Oakdale	0.09	Tower	6.00	2	2
3	Split Rock	Pathfinder Peaking	0.40	Pole	18.00	1	1
4	Rapindan	Butterfield	(0.11)	Pole	18.00	1	1
5	Jordan	Scott Co.	0.11	Pole	27.00	1	1
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
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27							
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33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.59		79.00	7	7

* Estimated

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	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Device	Total	
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
2312	ACSR		115		$70,363	$26,269	$96,631	1
853	ACSR		115		77,017	19,254	96,272	2
795	ACSR		115		51,853	51,776	103,629	3
336.4	ACSR		69		719,685	481,806	1,201,490	4
795	ACSR		69		* 14,467	* 32,200	* 46,667	5
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								42
								43
				0	$933,385	$611,304	$1,544,689	44

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 10,000 Kva, 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-Stearns County, MN	Trans U	110.00	36.20	
2		Trans U	110.00	69.00	13.80
3		Trans U	66.00	13.20	
4	Franklin-Birch Cooley TWP, MN	Trans U	110.00	70.60	13.80
5		Trans U	69.00	25.00	
6		Trans U	69.00	4.00	
7	Lincoln Co-So Sioux Falls SD	Trans U	110.00	70.60	13.80
8		Trans U	115.00	110.00	13.80
9	Prairie, SW of Grand Forks, ND	Trans U	230.00	118.00	13.80
10		Trans U	110.00	70.60	13.80
11	West Coon Rapids-Brklyn Pk, MN	Trans U	112.50	78.75	2.45
12		Trans U	104.30	66.00	2.40
13		Trans U	67.00	13.09	
14		Trans U	68.80	13.09	
15		Trans U	68.80	25.00	
16	Douglas County-Osakis, MN	Trans U	110.00	70.60	35.30
17	King-Oak Park Heights, MN	Trans A	345.00	118.00	13.80
18		Trans A	345.00	20.00	
19	Grant-Grant TWSP, SD	Trans U	115.00	72.00	2.40
20	Westgate-Eden Prairie, MN	Trans U	110.00	70.60	13.80
21		Trans U	116.00	70.60	13.80
22		Trans U	118.00	14.40	
23		Trans U	110.00	13.80	
24	Parkers Lake-Plymouth, MN	Trans U	345.00	115.00	13.80
25		Trans U	110.00	13.80	
26		Trans U	118.00	14.40	83.00
27	West Faribault-Warsaw TWP, MN	Trans U	68.80	13.80	
28		Trans U	68.80	13.80	
29		Trans U	110.00	70.60	2.50
30		Trans U	110.00	70.60	2.50
31	Monticello Nuclear-Mntclo, MN	Trans A	345.00	22.00	
32		Trans A	345.00	230.00	13.80
33		Trans A	345.00	118.00	13.80
34	Facilities at Maple River, ND	Trans U	230.00	118.00	13.80
35	Rogers Lake-Mendota Heights, MN	Trans U	118.00	14.40	
36		Trans U	110.00	70.60	
37	Cannon Falls-Dakota Co, MN	Trans A	68.80	13.80	
38		Trans A	110.00	70.60	
39		Trans A	161.00	118.00	13.80
40		Trans A	110.00	70.60	

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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. Lesignate 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 (k)	Line No.
13	2		Regulators	1	1,000	1
38	2		Capacitor Bank	1	14,400	2
9	3	1	Regulators	1	750	3
93	2		Regulators	3	864	4
5	3					5
1	3		Regulators	3	144	6
70	1		Capacitor Bank	2	28,800	7
28	1					8
187	1					9
140	2					10
24	3					11
23	3	2				12
13	2		Regulators			13
6	1		Regulators	3	999	14
8	1		Regulators	3	1,248	15
47	1		Capacitor Bank	1	14,400	16
448	1		Grounding Bank	3	30	17
784	1					18
19	1					19
47	1					20
47	1					21
47	1					22
47	1					23
900	6					24
93	2		Grounding Bank	3	30	25
47	1					26
6	1		Regulators	2	1,874	27
45	2					28
70	1					29
50	2					30
728	1					31
336	1					32
280	1					33
187	1					34
93	2					35
47	1					36
11	1					37
47	1					38
187	1					39
47	1					40

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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 10,000 Kva, 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	St Cloud#1-St. Cloud, MN	Trans A	34.50	4.36	
2		Trans A	110.00	36.20	
3		Trans A	33.00	2.42	
4		Trans A	33.00	19.03	
5		Trans A			
6		Trans A			
7	Red Rock-Newport, MN	Trans U	110.00	13.80	
8		Trans U	118.00	13.80	
9		Trans U	345.00	118.00	13.80
10		Trans U	345.00	230.00	13.80
11	Adams (Interstate Power), MN	Trans U	345.00	165.00	13.80
12	Lake Yankton-Lyon County, SD	Trans U	115.00	72.00	2.30
13		Trans U	115.00	72.00	13.80
14		Trans U	69.00	24.90	2.45
15	Crow River-Wright County, MN	Trans U	110.00	70.60	13.80
16	Scott County-Jackson TWSP, MN	Trans U	110.00	70.60	13.80
17	Carver County-Benton TWSP, MN	Trans U	110.00	70.60	2.50
18	Inver Grove-Inv Grove TWP, MN	Trans U	110.00	70.60	13.80
19	Wakefield-Wakefield TWSP, MN	Trans U	118.00	65.50	
20		Trans U	69.00	23.90	
21		Trans U	110.00	69.00	
22		Trans U	63.00	13.20	
23	Chisago County-Lent TWSP, MN	Trans U	500.00	345.00	
24		Trans U	500.00	345.00	
25		Trans U	500.00	345.00	
26		Trans U			
27	Riverside-Minneapolis, MN	Trans A	118.00	14.40	
28		Trans A	118.00	14.40	
29		Trans A	115.00	22.00	
30		Trans A	115.00	66.57	
31	High Bridge-St. Paul, MN	Trans A	115.00	13.80	
32		Trans A	115.00	18.00	
33	Black Dog-Bloomington, MN	Trans A	115.00	13.80	
34		Trans A	115.00	13.80	
35		Trans A	115.00	13.80	
36		Trans A	230.00	118.00	13.80
37	Wilmarth-Mankato, MN	Trans A	69.00	13.80	
38		Trans A	161.00	118.00	13.80
39		Trans A	68.80	13.80	
40		Trans A	110.00	70.60	13.80

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 (k)	Line No.
4	1					1
83	2		Regulators	1	500	2
5	3		Regulators	1	500	3
3	3		Regulators	1	500	4
			Grounding Bank	1	10,000	5
			Grounding Bank	1	7,500	6
40	2		Regulators	1	937	7
47	1					8
448	1					9
336	1		Capacitor Bank	3	248,400	10
300	1		Grounding Bank	3	30	11
15	1					12
15	1					13
3	3	1	Grounding Bank	1	40,000	14
112	1					15
133	2					16
42	1					17
125	2					18
19	3		Grounding Bank	1	6,250	19
1	1		Regulators	1	18,750	20
10	1					21
2	3					22
401	1	1	Capacitor Bank	4	96,000	23
401	1		Grounding Bank	3	300	24
401	1		Grounding Bank	3	30	25
			Capacitor Bank	3	164,680	26
47	1					27
47	1					28
275	1					29
185	1					30
133	1		Regulators	8	3,981	31
192	1					32
100	2					33
266	2					34
192	1					35
187	1					36
19	2		Grounding Bank	2	159,400	37
112	1		Regulators	6	5,435	38
93	2					39
140	2					40

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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 10,000 Kva, 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	Wilmarth-Mankato, MN	Trans A	110.00	70.60	13.80
2		Trans A	345.00	188.00	13.80
3	Minn Valley-Granite Falls, MN	Trans A	69.00	13.80	
4		Trans A	115.00	13.80	
5		Trans A	230.00	115.00	
6		Trans A	23.90	13.80	
7		Trans A	110.00	70.60	13.80
8		Trans A	115.00	72.00	
9		Trans A	230.00	115.00	
10	Lawrence-Mapleton TWSP, SD	Trans A	110.00	70.60	13.80
11		Trans A	69.00	13.80	
12		Trans A	110.00	70.60	13.80
13	Benton County-St. Cloud, MN	Trans U	230.00	118.00	13.80
14		Trans U	230.00	118.00	13.80
15	Pathfinder-Brandon TWSP, SD	Trans A	115.00	66.40	13.80
16	Red Wing-Red Wing, MN	Trans A	69.00	13.80	
17		Trans A			
18	Granite City-St. Cloud, MN	Trans U	118.00	14.40	4.00
19		Trans U	118.00	36.20	
20	Lake Pulaski-Buffalo, MN	Trans U	116.00	70.60	
21		Trans U	118.00	36.20	
22	Prairie Island-Red Wing, MN	Trans A	345.00	20.00	
23		Trans A	345.00	20.00	
24		Trans A	345.00	161.00	13.80
25	Coon Creek-Coon Rapids, MN	Trans U	345.00	118.00	13.80
26		Trans U	345.00	118.00	13.80
27		Trans U	115.00	13.80	13.80
28	Inver Hills-Inver Grove Hts., MN	Trans A	124.00	14.40	
29		Trans A	124.00	14.40	
30		Trans A	345.00	118.00	13.80
31		Trans A	124.00	14.40	
32	Blue Lake-Shakopee, MN	Trans U	345.00	118.00	13.80
33		Trans U	110.00	13.80	
34		Trans U	127.00	14.40	
35	Kohlman Lake-Maplewood, MN	Trans U	345.00	118.00	13.80
36		Trans U	345.00	115.00	
37		Trans U	118.00	14.40	
38	Sherburne County-Becker, MN	Trans U	345.00	24.00	
39		Trans U	345.00	24.00	
40	Fort Ridgley-New Ulm, MN	Trans U	116.00	92.95	

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 (k)	Line No.
70	1					1
448	1					2
25	6	1				3
50	1					4
100	2					5
8	6		Regulators	2	750	6
47	1					7
42	1					8
112	1					9
93	2					10
20	1					11
112	1					12
187	1					13
186	1					14
85	1					15
40	4		Regulators	5	4,124	16
			Regulators	3	999	17
93	2		Regulators	3	2,811	18
70	1					19
70	1					20
28	1					21
672	1					22
672	1					23
224	1					24
448	1					25
448	1					26
25	1					27
140	1					28
140	1					29
550	1					30
140	1					31
336	1		Regulators	3	1,248	32
50	2					33
246	2		Regulators	2	7,900	34
448	1					35
450	1		Capacitor Bank	3	248,400	36
47	1		Grounding Bank	1	40,000	37
800	1					38
800	1					39
70	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	Split Rock-Brandon TWSP, SD	Trans U	345.00	118.00	13.80
2		Trans U	161.00	118.00	13.80
3	Eden Prairie-Eden Prairie, MN	Trans U	345.00	118.00	13.80
4		Trans U	118.00	14.40	8.31
5	Forbes-Lavell TWSP, MN	Trans U	500.00		
6		Trans U			
7		Trans U			
8	Sheyenne Sub-Fargo, ND	Trans U	230.00	115.00	13.80
9		Trans U	230.00	118.00	13.80
10	Roseau County, MN	Trans U			
11	Buffalo Ridge-Benton, SD	Trans U	118.00	36.20	
12	Gopher-Minneapolis, MN	Distr U	118.00	14.40	
13		Distr U	118.00	14.40	
14	Garfield-Minneapolis, MN	Distr U	13.70	4.24	
15	Elm Creek, MN	Distr U	110.00	13.80	
16	Main St, Minneapolis, MN	Distr A	118.00	14.40	
17	Nicollet-Minneapolis, MN	Distr U	13.80	4.24	
18	Oakland-Minneapolis, MN	Distr U	13.70	4.24	
19	Osseo-Maple Grove, MN	Distr U	118.00	14.40	
20	Quincy-Minneapolis, MN	Distr U	13.70	4.24	
21	St. Louis Park, St. Louis Park, MN	Distr U	110.00	13.80	
22		Distr U	110.00	13.80	
23		Distr U	110.00	13.80	
24		Distr U	118.00	14.40	
25		Distr U	15.00	13.80	
26	Elliot Park Minneapolis, MN	Distr U	118.00	14.40	
27		Distr U	115.00	13.80	
28	Wold-Chamberlain-Minneapolis, MN	Distr U	13.20	4.36	
29	Twin Lakes-Brooklyn Ctr., MN	Distr U	118.00	14.40	
30	Aldrich-Minneapolis, MN	Distr U	121.00	14.40	
31		Distr U	118.00	14.40	
32		Distr U	118.00	14.40	
33	Southtown-Minneapolis, MN	Distr U	110.00	14.00	
34	Wilson-Bloomington, MN	Distr U	112.00	13.80	
35		Distr U	118.00	14.40	
36	Terminal-Lauderdale, MN	Distr U	345.00	118.00	
37		Distr U	345.00	118.00	
38		Distr U	115.00	13.80	
39		Distr U	13.20	4.36	
40	Nine Mile Creek, MN	Distr U	115.00	13.80	

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 (k)	Line No.
896	2					1
93	2		Capacitor Bank	1	40,500	2
448	1					3
93	2					4
168	1		Grounding Bank	1	831	5
			Capacitor Bank	2	6[illegible]0,000	6
			Capacitor Bank	3	400,000	7
187	1					8
187	1					9
			Capacitor Bank	2	329,360	10
28	1					11
47	1					12
47	1					13
15	6		Regulators	30	2,106	14
25	1					15
140	2					16
15	3					17
15	6		Regulators	18	1,185	18
140	1					19
15	6		Regulators	13	957	20
17	1					21
25	2		Grounding Bank	1	2,000	22
20	1					23
140	2					24
8	3					25
47	1					26
47	1					27
10	2					28
210	3					29
47	1		Grounding Bank	1	79,600	30
140	2					31
47	1					32
195	3					33
70	6		Grounding Bank	2	10,333	34
140	2					35
448	1					36
448	1					37
100	4					38
15	2		Regulators	17	1,182	39
28	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	Edina-Edina, MN	Distr U	118.00	14.40	
2	Medicine Lake-Golden Valley, MN	Distr U	118.00	14.40	
3	Savage-Dakota County, MN	Distr U	110.00	13.80	
4	Moore Lake-Fridley, MN	Distr U	118.00	14.40	
5		Distr U	108.00	13.69	
6	Airport-Minneapolis, MN	Distr U	118.00	14.40	
7	Bloomington-Bloomington, MN	Distr U	115.00	13.80	
8	Riverwood-Burnsville, MN	Distr U	110.00	63.50	13.80
9	Brooklyn Park-Brooklyn Park, MN	Distr U	110.00	13.80	
10	Apache-St Anthony, MN	Distr U	118.00	14.40	
11	Indiana-Robbinsdale, MN	Distr U	110.00	13.80	
12		Distr U	118.00	14.40	
13	Bassett Creek, MN	Distr U	118.00	14.40	
14	Fifth Street-Minneapolis, MN	Distr U	110.00	13.80	
15	Crooked Lake-Coon Rapids, MN	Distr U	119.00	13.80	
16		Distr U	13.80	12.47	
17	Hyland Lake-Edina, MN	Distr U	118.00	14.40	
18		Distr U	118.00	14.40	
19	Dodge Center-Dodge Center, MN	Distr U	69.00	13.80	
20	Faribault-Faribault, MN	Distr U	69.00	39.83	2.30
21		Distr U	69.00	13.09	
22	Farmington-Farmington, MN	Distr U	68.80	13.80	
23		Distr U	68.80	13.80	
24	Hastings-Hastings, MN	Distr U	68.80	13.80	
25	Waseca-Waseca, MN	Distr U	69.00	4.33	
26		Distr U	68.00	26.18	
27		Distr U			
28		Distr U	68.80	13.80	
29	Zumbrota-Zumbrota, MN	Distr U	68.80	13.09	
30		Distr U			
31		Distr U	70.70	25.00	2.40
32	Pine Island-Pine Island, MN	Distr U	68.80	13.09	
33		Distr U			
34	Airlake-Lakeville, MN	Distr U	68.80	13.80	
35	Northfield-Northfield, MN	Distr U	68.80	13.80	
36		Distr U	68.80	13.80	
37	Waterville, Waterville, MN	Distr U	68.80	26.18	
38		Distr U	68.80	4.36	
39		Distr U	65.43	14.70	
40	Fair Park-Faribault, MN	Distr U	68.80	13.80	

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 (k)	Line No.
210	3					1
210	3					2
53	2		Regulators	6	3,882	3
140	2					4
50	1					5
93	2					6
93	2					7
25	1					8
50	2					9
140	2					10
39	1					11
28	1					12
28	1					13
336	4					14
93	2					15
10	3					16
47	1					17
47	1					18
11	1		Capacitor Bank	1	5,400	19
8	3		Regulators	12	876	20
14	1		Capacitor Bank	1	7,200	21
14	1					22
11	1					23
56	2					24
8	2		Regulators	3	864	25
14	1					26
	3	1	Regulators	2	1,300	27
13	1		Regulators	3	864	28
7	1		Regulators	3	216	29
			Capacitor Bank	1	7,200	30
2	3		Regulators	2	1,125	31
6	1		Regulators	2	1,000	32
			Capacitor Bank	1	5,400	33
28	2					34
28	1		Grounding Bank	3	750	35
28	1					36
6	1		Regulators	6	660	37
2	1		Capacitor Bank	1	7,200	38
2	3		Regulators	1	225	39
21	2		Capacitor Bank	1	7,200	40

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 10,000 Kva, 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	Kasson-Kasson, MN	Distr U	68.80	13.80	
2	Annandale, MN	Distr U	67.00	13.09	
3		Distr U			
4	Becker, MN	Distr U	67.00	35.30	
5		Distr U	118.00	36.20	
6	Cold Spring, MN	Distr U	68.80	13.09	
7		Distr U	34.73	2.42	
8	Glenwood, MN	Distr U	69.00	4.16	
9		Distr U	68.80	13.09	
10	Industrial-St Cloud, MN	Distr U	34.50	12.52	
11		Distr U	34.50	4.33	
12	Linn Street, MN	Distr U	68.80	13.09	
13		Distr U	68.80	13.09	
14	St Joseph, MN	Distr U	68.80	13.09	
15		Distr U			
16	Albany Substation-Albany, MN	Distr U	68.80	12.47	
17		Distr U	13.20	4.36	
18	New Avon, MN	Distr U	68.80	13.09	
19		Distr U			
20	Empire Park, MN	Distr U	34.40	4.36	
21	Southside, MN	Distr U	68.80	13.09	
22	MEI, MN	Distr U	110.00	13.80	
23		Distr U	15.00	8.66	
24	Crossroads, MN	Distr U	110.00	13.80	
25		Distr U	115.00	13.80	
26	Salida Crossing, MN	Distr U	118.00	13.80	
27	Pipestone-Pipestone, MN	Distr U	69.00	4.33	
28		Distr U	69.00	24.25	
29		Distr U	115.00	72.00	13.80
30	Cherry Creek, SD	Distr U	118.00	14.40	
31		Distr U	69.00	7.50	
32	Cliff A[illegible]nue-Sioux Falls, SD	Distr U	69.00	4.16	
33		Distr U	68.80	13.09	
34	Dell Rapids-Dell Rapids, SD	Distr U	68.80	13.80	
35		Distr U			
36	Silver Creek-Sioux Falls, SD	Distr U	68.80	13.80	
37		Distr U	68.80	13.80	
38	Sioux Falls-Sioux Falls, SD	Distr U	68.80	13.80	
39	So Sioux Falls-Sioux Fall, SD	Distr U	68.80	13.80	
40		Distr U	69.00	4.33	

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 (k)	Line No.
9	1		Regulators	6	1,002	1
6	1		Regulators	1	937	2
			Capacitor Bank	1	5,400	3
5	1		Regulators	1	750	4
7	1					5
7	1		Regulators	2	1,000	6
4	3		Regulators	3	216	7
8	3	1	Regulators	9	933	8
5	1		Capacitor Bank	1	7,200	9
13	2					10
2	3		Regulators	3	225	11
11	1		Regulators	6	1,002	12
11	1		Regulators	7	1,085	13
4	1		Regulators	6	432	14
			Capacitor Bank	1	10,800	15
11	1		Regulators	6	1,002	16
6	1					17
4	1		Regulators	3	501	18
			Capacitor Bank	1	10,800	19
14	2					20
11	1		Regulators	1	937	21
17	1					22
3	1					23
50	2					24
22	1					25
14	1					26
19	2		Regulators	15	1,380	27
3	2					28
25	1					29
37	1		Regulators	3	999	30
0	1		Regulators	6	1,988	31
7	1		Regulators	6	432	32
11	1		Regulators	2	450	33
9	1		Regulators	3	501	34
			Regulators	3	501	35
11	1					36
11	1					37
56	2					38
56	2					39
13	2		Regulators	3	725	40

Name of Respondent Northern States Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 10,000 Kva, 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	So Sioux Falls-Sioux Falls, SD	Distr U			
2	Tracy SW Station-Tracy, MN	Distr U	69.00	13.80	
3		Distr U			
4	West Sioux Falls-Sioux Fall, SD	Distr U	67.00	4.36	
5		Distr U	110.00	70.60	13.80
6		Distr U	118.00	14.40	
7	Minnehaha, SD	Distr U	118.00	14.40	8.31
8		Distr U	118.00	14.40	
9	Canistota Jnct-Grand TWSP, SD	Distr U	74.00	13.80	
10		Distr U			
11	Lester Prairie, MN	Distr U	68.80	13.09	
12		Distr U			
13	Montevideo, MN	Distr U	69.00	4.33	
14		Distr U	68.80	13.09	
15		Distr U	13.20	4.36	
16	Winsted, MN	Distr U	68.80	4.36	
17	Young America, MN	Distr U	69.00	12.50	
18		Distr U	69.00	13.80	
19	Credit River-Prior Lake, MN	Distr U	68.80	13.09	
20	Wyoming-Wyoming TWP, MN	Distr U	68.80	13.09	
21		Distr U	68.80	13.09	
22		Distr U			
23	Cleveland-St. Paul, MN	Distr U	13.20	4.36	
24	Forest Sub-St. Paul, MN	Distr U	14.00	4.33	
25		Distr U			
26		Distr U			
27	Prior-St. Paul, MN	Distr U	118.00	14.40	
28	Afton Sub-Afton, MN	Distr U	118.00	36.20	
29	Roseplace-Roseville, MN	Distr U	118.00	14.40	
30	Battle Creek, MN	Distr U	118.00	14.40	
31	St. Clair-St. Paul, MN	Distr U	13.80	4.24	
32	Oakdale-Oakdale, MN	Distr U	118.00	14.40	
33	Baytown-Baytown, MN	Distr U	118.00	14.40	
34	Birch-Birch, MN	Distr U	68.80	36.20	
35	Ramsey-Little Canada, MN	Distr U	108.90	13.69	
36		Distr U			
37		Distr U			
38	Merriam Park-St. Paul, MN	Distr U	110.00	14.00	
39	Western-St. Paul, MN	Distr U	118.00	14.40	
40	Koch Refinery-Rosemount, MN	Distr U	68.80	4.36	

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 (k)	Line No.
			Regulators	6	438	1
5	1		Regulators	3	501	2
			Capacitor Bank	1	5,400	3
6	1		Regulators	3	216	4
70	1		Regulators	1	225	5
140	2					6
28	1					7
28	1					8
8			Regulators	1	500	9
			Capacitor Bank	1	5,400	10
8	1		Regulators	2	1,125	11
			Grounding Bank	1	10,000	12
6	1		Grounding Bank	1	5,000	13
5	1		Regulators	1	625	14
			Regulators	9	657	15
11	1		Regulators	3	501	16
9	1		Regulators	3	750	17
11	1		Regulators	3	1,248	18
14	1					19
18	1		Regulators	2	1,687	20
31	1		Capacitor Bank	3	16,200	21
			Regulators	6	2,496	22
10	2		Regulators	2	1,000	23
20	2		Grounding Bank	3	1,875	24
			Regulators	1	225	25
			Regulators	18	1,305	26
28	1					27
93	2					28
93	2					29
93	2					30
10	2		Regulators	18	1,296	31
93	2					32
28	1					33
17	1		Regulators	3	1,200	34
100	2		Regulators	5	4,498	35
			Regulators	6	1,998	36
			Grounding Bank	2	6,772	37
188	3					38
140	2					39
25	4					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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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Koch Refinery-Rosemount, MN	Distr U	68.80	4.36	
2		Distr U	68.80	13.80	
3		Distr U	118.00	14.40	
4		Distr U	13.80	4.16	
5	Williams Bros-Apple Valley, MN	Distr U	110.00	14.00	
6		Distr U	15.00	13.80	
7		Distr U	14.00	4.33	
8	Stockyards-So. St. Paul, MN	Distr U	110.00	13.80	
9	Daytons Bluff-St. Paul, MN	Distr U	110.00	14.00	
10	Pine Bend-Rosemount, MN	Distr U	68.80	4.36	
11		Distr U	67.00	13.50	
12	Tanners Lake-Maplewood, MN	Distr U	118.00	14.40	
13		Distr U	14.40	12.47	
14	Upper Levee-St. Paul	Distr U	115.00	13.80	
15	Chemolite-Cottage Grove	Distr U	110.00	13.09	
16		Distr U	110.00	70.60	13.80
17	Rondo-St. Paul, MN	Distr U	13.20	4.36	
18	Linde-Inver Grove Hights, MN	Distr U	115.00	13.20	
19		Distr U	14.00	12.99	
20	Arden Hills-Arden Hills, MN	Distr U	110.00	70.60	13.80
21		Distr U			
22	Shepard-St. Paul, MN	Distr U	110.00	13.80	
23	North Star Steel-St. Paul, MN	Distr U	110.00	13.80	
24	Cottage Grove-Cottage Grove, MN	Distr U	118.00	14.40	
25	Lexington-Arden Hills, MN	Distr U	110.00	13.80	
26		Distr U	118.00	36.20	
27		Distr U	36.20	14.40	
28	Cedarvale-St. Paul, MN	Distr U	110.00	13.80	
29	Rich Valley-Inver Grove, MN	Distr U	118.00	14.40	
30	Maxwell-St. Paul, MN	Distr U	118.00	4.16	
31	Lone Oak, MN	Distr U	68.80	13.80	
32	Woodbury, MN	Distr U	118.00	34.50	
33	West Byron, MN	Distr U	69.00	12.50	
34	Eastwood-Mankato, MN	Distr U	68.80	13.80	
35	Sibley Park, MN	Distr U	68.80	13.80	
36		Distr U	68.80	13.80	
37	St. James Municipal-St. James, MN	Distr U	68.80	13.09	
38	Hugo-Hugo, MN	Distr U	68.80	13.09	
39	Oak Park-Oak Park Heights, MN	Distr U	118.00	68.60	
40		Distr U	118.00	68.60	

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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 (k)	Line No.
19	2					1
56	2					2
140	3		Capacitor Bank	1	14,840	3
28	1					4
9	1		Regulators	1	937	5
3	1					6
8	1					7
93	2					8
188	3					9
10	2		Regulators	1	937	10
9	1					11
140	2					12
70	21	1				13
210	3					14
50	2					15
47	1		Regulators	1	937	16
10	2		Regulators	2	1,000	17
50	1					18
2	1					19
140	2		Regulators	4	3,748	20
			Grounding Bank	2	4,800	21
50	2					22
93	2					23
93	2					24
93	2					25
47	1					26
47	1					27
43	2		Regulators	7	4,124	28
28	1					29
28	1					30
56	2					31
47	1					32
11	1		Regulators	3	999	33
56	2					34
26	1					35
27	1					36
14	1					37
14	1		Regulators	2	750	38
28	1					39
7	3	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	Oak Park-Oak Park Heights, MN	Distr U	118.00	14.40	64.70
2	Goose Lake-Ramsey County, MN	Distr U	118.00	14.40	
3		Distr U	110.00	70.60	13.80
4	Minnesota Pipeline-Ramsey County, MN	Distr U	68.80	13.09	
5	Lindstrom-Lindstrom, MN	Distr U	68.80	13.80	
6	Long Lake-Northdale TWP, MN	Distr U	115.00	13.80	
7		Distr U	115.00	13.80	
8	North Broadway-Fargo TWP, ND	Distr U	22.90	4.36	
9	Barnes-Barnes TWP, ND	Distr U	22.90	4.36	
10	Woodrow-Fargo, ND	Distr U	22.90	4.36	
11	Red River-Fargo, ND	Distr U	110.00	63.50	13.80
12		Distr U	118.00	68.13	13.80
13		Distr U	118.00	68.10	13.80
14	Cass County-Barnes TWP, ND	Distr U	110.00	24.10	2.40
15		Distr U	118.00	68.12	13.80
16	Nordic Sub-Grand Forks, ND	Distr U	119.00	13.80	
17	Park Substation, MN	Distr U	68.80	4.36	
18	Water Plant-Grand Forks, ND	Distr U	68.80	4.36	
19	Mayville-Mayville, ND	Distr U	68.80	4.36	
20		Distr U	68.80	13.09	
21		Distr U			
22	Gateway-Grand Forks, ND	Distr U	68.80	13.80	
23		Distr U	68.80	13.80	
24	Portal Pipeline-Minot, ND	Distr U	14.00	4.30	
25	Souris-Minot, ND	Distr U	110.00	13.80	
26		Distr U	110.00	13.80	
27	Hollydale, MN	Distr U	68.80	14.40	
28	Waconia Switching-Waconia, MN	Distr U	68.80	13.80	
29	Bluff Creek, MN	Distr U	118.00	14.40	
30	Chaska, MN	Distr U	68.80	13.80	
31		Distr U	70.60	13.80	
32	Excelsior, MN	Distr U	68.80	13.80	
33		Distr U			
34	Deephaven, MN	Distr U	68.80	13.80	
35	Gleason Lake, MN	Distr U	118.00	14.40	
36		Distr U	110.00	13.80	
37		Distr U	110.00	70.60	13.80
38	Glen Lake, MN	Distr U	68.80	13.80	
39	Shakopee, MN	Distr U	68.80	13.80	
40		Distr U	13.70	4.24	

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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 (k)	Line No.
93	2					1
93	2					2
42	1					3
11	1					4
21	2					5
22	1		Regulators	2	2,187	6
28	1		Regulators	3	999	7
11	2		Regulators	2	1,000	8
10	2		Regulators	15	1,098	9
13	2		Regulators	15	1,062	10
47	1	1				11
91	1					12
91	1					13
50	2					14
47	1					15
93	2					16
11	1					17
11	1					18
6	1		Regulators	12	1,244	19
6	1					20
			Capacitor Bank	1	5,400	21
25	1					22
28	1					23
10	2					24
50	2					25
25	1					26
28	1					27
22	1					28
47	1					29
11	1		Regulators	3	501	30
22	1					31
19	1		Capacitor Bank	1	14,400	32
			Regulators	6	1,998	33
56	2					34
47	1					35
47	1					36
112	1					37
56	2		Regulators	5	3,937	38
56	2					39
6	3					40

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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 10,000 Kva, 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	Orono, MN	Distr U	68.80	13.80	
2	Mound, MN	Distr U	68.80	13.80	
3	Watertown, MN	Distr U	72.40	13.80	
4	Winona-Winona, MN	Distr U	68.80	13.80	
5	Goodview-Goodview, MN	Distr U	68.80	13.09	
6	La Crescent-La Crescent, MN	Distr U	68.80	13.80	
7	Wabasha-Wabasha, MN	Distr U	69.00	13.09	
8		Distr U	69.00	12.99	
9		Distr U			
10	Burnside-Red Wing, MN	Distr U	68.80	13.09	
11		Distr U	68.80	13.80	
12	East Winona-Winona, MN	Distr U	69.00	13.80	75.60
13					
14					
15	198 Substations with capacities over 10,000 KVA				
16	143 Substations with capacities under 10,000 KVA				
17	Aggregated Capacity 454,908 KVA				
18					
19	Transmission Subs - 2				
20	Distribution Subs - 141				
21					
22	TOTAL 143				
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
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36					
37					
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39					
40					

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (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 (k)	Line No.
22	1					1
56	2					2
11	1		Regulators	6	1,002	3
56	2		Capacitor Bank	1	7,200	4
56	2		Capacitor Bank	1	7,200	5
11	1					6
11	1		Capacitor Bank	1	7,200	7
2	1		Regulators	2	144	8
						9
7	1		Regulators	1	750	10
11	1					11
11	1		Regulators	3	999	12
						13
						14
						15
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Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	1,413,722	207,073	12,071
2	Additions During Year			
3	Purchases	56,756	4,623	351
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	56,756	4,623	351
6	Reductions During Year			
7	Retirements	58,113	2,741	140
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	58,113	2,741	140
10	Number at End of Year (Lines 1+5-9)	1,412,365	208,955	12,282
11	In Stock	48,875	6,944	717
12	Locked Meters on Customers' Premises	36,529		
13	Inactive Transformers on System			
14	In Customers' Use	1,326,577	202,011	11,565
15	In Company's Use	384		
16	TOTAL End of Year (Enter Total of lines 11 to 15. This line should equal line 10.)	1,412,365	208,955	12,282

Name of Respondent Northern States Power Company	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/09/95	Year of Report Dec. 31, 1994

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	$12,704,551	$1,038,694	$127,597,236	$588,682,613	$588,682,613
2	Water Pollution Control Facilities		17,996	(1,845,172)	124,340,275	124,340,275
3	Solid Waste Disposal Costs	1,979	238,000		51,983,464	51,983,464
4	Noise Abatement Equipment				7,095,661	7,095,661
5	Esthetic Costs				22,255,402	22,255,402
6	Additional Plant Capacity				84,600,000	84,600,000
7	Miscellaneous (Identify significant)				0	0
8	TOTAL (Total of lines 1 thru 7)	$12,706,530	$1,294,690	$125,752,064	$878,957,415	$878,957,415
9	Construction Work in Progress				40,839,498	40,839,498

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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	$23,771,315	$23,771,315
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	9,570,089	9,570,089
3	Fuel Related Costs		
4	Operation of Facilities	769,844	769,844
5	Fly Ash and Sulfur Sludge Removal	11,814,368	11,814,368
6	Difference in Cost of Environmentally Clean Fuels	0	0
7	Replacement Power Costs	14,110,925	4,314,099
8	Taxes and Fees	6,433,447	6,433,447
9	Administrative and General	1,819,039	1,819,039
10	Other (Identify significant)	* 14,004,991	14,004,991
11	TOTAL	$82,294,018	$72,497,192

< P431-10(b) >

Line #10 Includes the following:

Reclamation Costs	11,867,749
Research & Development	2,137,242
TOTAL	14,004,991

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