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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

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

3 PU-19-177 Filed 05/01/2019 Pages: 341
FERC Financial Report - FERC Form No. 1
Northern States Power Company

Exact Legal Name of Respondent (Company)	Year/Period of Report
Northern States Power Company (Minnesota)	End of 2018/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

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

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

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

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

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

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

IV. When to Submit:

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

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

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

GENERAL INSTRUCTIONS

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

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)		02 Year/Period of Report End of 2018/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /		
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 414 Nicollet Mall, Minneapolis, MN 55401		
05 Name of Contact Person Jeffrey S. Savage		06 Title of Contact Person Sr. Vice Pres., Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 414 Nicollet Mall, Minneapolis, MN 55401		
08 Telephone of Contact Person, *Including Area Code* (612) 330-5658	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/18/2019

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Jeffrey S. Savage	03 Signature Jeffrey S. Savage	04 Date Signed *(Mo, Da, Yr)* 04/18/2019
02 Title Senior Vice President, Controller		

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

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	N/A
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

GENERAL INFORMATION

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

Jeffrey S. Savage
Senior Vice President, Controller
414 Nicollet Mall
Minneapolis, MN 55401

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Northern States Power Co. (a Minnesota corporation) was incorporated in the state of Minnesota on March 9, 2000.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

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

During the year 2018, the respondent furnished electric utility and natural gas utility service in the states of Minnesota and North Dakota and electric utility and intrastate natural gas transportation service in the state of South Dakota.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

CONTROL OVER RESPONDENT

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NSP Nuclear Corp	Nuclear generation support	100	
2	Private Fuel Storage, LLC	Nuclear waste storage	32.8	
3	United Power and Land Co.	Real estate holdings	100	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board, Chief Executive Officer	Ben Fowke	503,580
2	Senior VP, Chief Nuclear Officer	Timothy J. O'Connor	525,000
3	President	Christopher B. Clark	355,000
4	Executive VP, Chief Financial Officer	Robert C. Frenzel	261,861
5	Executive VP	Kent T. Larson	241,715
6	Executive VP, General Counsel	Scott M. Wilensky	215,547
7	Senior VP, Chief Human Resources Officer	Darla Figoli	198,514
8	Senior VP, Corporate Secretary	Judy M. Poferl	145,030
9	Executive VP, Chief Customer and Innovations Officer	Brett Carter	131,118
10	Senior VP, Controller	Jeffrey S. Savage	128,916
11	Senior VP, Finance and Corporate Development	Brian J. Van Abel	123,542
12	Executive VP	David L. Eves	115,138
13	Executive VP	Marvin E. McDaniel, Jr.	101,756
14			
15	Salaries represent NSP-Minnesota's allocation of		
16	officers' salaries greater than $50,000 for the period		
17	of time that was served as an officer for		
18	NSP-Minnesota.		
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Schedule Page: 104 Line No.: 7 Column: a

Darla Figoli was elected Senior VP and Chief Human Resources Officer effective May 7, 2018. Figoli assumed a portion of Marvin E. McDaniel, Jr.'s responsibilities.

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

Brett Carter was elected Executive VP and Chief Customer and Innovations Officer effective May 7, 2018. Carter assumed a portion of Marvin E. McDaniel, Jr.'s responsibilities.

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

Brian J. Van Abel resigned as VP, Treasurer effective Sept. 1, 2018. Van Abel was elected Senior VP of Finance and Corporate Development effective Sept. 1, 2018.

Schedule Page: 104 Line No.: 12 Column: a

David L. Eves was elected Executive VP effective March 1, 2018.

Schedule Page: 104 Line No.: 13 Column: a

Marvin E. McDaniel, Jr. resigned as Executive VP effective March 1, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Ben Fowke, Chairman of the Board, Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401
2	Robert C. Frenzel, Executive VP, CFO	414 Nicollet Mall, Minneapolis, MN 55401
3	Christopher B. Clark, President	414 Nicollet Mall, Minneapolis, MN 55401
4	Marvin E. McDaniel, Jr., Executive VP	414 Nicollet Mall, Minneapolis, MN 55401
5	David L. Eves, Executive VP	1800 Larimer Street, Suite 1100, Denver, CO 80202
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Schedule Page: 105 Line No.: 4 Column: a

Marvin E. McDaniel, Jr. resigned as Executive VP effective March 1, 2018.

Schedule Page: 105 Line No.: 5 Column: a

David L. Eves was elected Executive VP effective March 1, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

Does the respondent have formula rates?

[X] Yes
[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff, Third Revised Volume No. 1	ER07-1415-000 - Order Granting Incentives,
2	(Midwest Independent Transmission System	and Accepting Proposed Rate Formula
3	Operator, Inc. Open Access Transmission and	Modifications, Subject to Conditions, Issued
4	Energy Markets Tariff, Attachment O-NSP)	December 21, 2007, Accession No. 20071221-3012
5		
6	FERC Electric Tariff, Fourth Revised Volume No. 1	ER10-541-000 - Approval of Tariff Revisions to
7	(Midwest Independent Transmission System	Attachment O-NSP, Issued February 26, 2010,
8	Operator, Inc. Open Access Transmission and	Accession No. 20100226-3041
9	Energy Markets Tariff, Attachment O-NSP)	
10		
11	FERC Electric Tariff updated effective 01-01-2012	ER12-297-000 - Approval of Tariff Revisions to
12	(Midwest Independent Transmission System	Attachment O-NSP, Issued December 21, 2011,
13	Operator, Inc. Open Access Transmission and	Accession No. 20111221-3033
14	Energy Markets Tariff, Attachment O-NSP)	
15		
16	FERC Electric Tariff updated effective 01-01-2013	ER13-674-000/001/002 Approval of Tariff Revisions
17	(Midwest Independent Transmission System	to Attachment O-NSP, Issued March 20, 2013,
18	Operator, Inc. Open Access Transmission and	Accession No. 20130320-3014
19	Energy Markets Tariff, Attachment O-NSP)	
20		
21	FERC Electric Tariff updated effective 11-19-2013	ER14-421-000/001 Approval of Tariff Revisions
22	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued March 11, 2014,
23	Operator, Inc. Open Access Transmission and	Accession No. 20140311-3041
24	Energy Markets Tariff, Attachment O-NSP,	
25	Attachment GG-NSP; & Attachment MM)	
26		
27	FERC Electric Tariff updated effective 01-06-2015	ER15-358-000 Approval of Tariff Revisions
28	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued January 6, 2015,
29	Operator, Inc. Open Access Transmission and	Accession No. 20150105-3035
30	Energy Markets Tariff, Attachment O-NSP)	
31		
32	FERC Electric Tariff updated effective 01-01-2016	ER16-197-000 Approval of Tariff Revisions
33	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 30, 2015,
34	Operator, Inc. Open Access Transmission and	Accession No. 20151230-3075
35	Energy Markets Tariff, Attachment O-NSP)	
36		
37	FERC Electric Tariff updated effective 01-01-2017	ER17-305-000 Approval of Tariff Revisions
38	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 30, 2016,
39	Operator, Inc. Open Access Transmission and	Accession No. 20161230-3022
40	Energy Markets Tariff, Attachment O-NSP)	
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

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

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff updated effective 12-01-2017	ER18-12-000 Approval of Tariff Revisions
2	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued November 29, 2017,
3	Operator, Inc. Open Access Transmission and	Accession No. 20171129-3095
4	Energy Markets Tariff, Attachment O-NSP)	
5		
6	FERC Electric Tariff updated effective 1-01-2019	ER18-2322-000 Approval of Tariff Revisions
7	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 20, 2018,
8	Operator, Inc. Open Access Transmission and	Accession No. 20181220-3030
9	Energy Markets Tariff, Attachment O-NSP)	
10		
11	FERC Electric Tariff updated effective 1-01-2019	ER19-249-000 Approval of Tariff Revisions
12	(Midcontinent Independent Transmission System	to Attachment O-NSP, Issued December 20, 2018,
13	Operator, Inc. Open Access Transmission and	Accession No. 20181220-3011
14	Energy Markets Tariff, Attachment O-NSP)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170308-5088	03/08/2017	ER17-1120-000	See footnote	FERC Electric Tariff updated effective
2					01-01-2017 (Midcontinent Independent
3					System Operator, Inc. Open
4					Access Transmission and Energy
5					Markets Tariff, Attachment O-NSP)
6					
7	20180313-5128	03/13/2018	ER18-1004-000	See footnote	FERC Electric Tariff updated effective
8					01-01-2018 (Midcontinent Independent
9					System Operator, Inc. Open
10					Access Transmission and Energy
11					Markets Tariff, Attachment O-NSP)
12					
13	20190314-5169	03/14/2019	ER19-1310-000	See footnote	FERC Electric Tariff updated effective
14					01-01-2019 (Midcontinent Independent
15					System Operator, Inc. Open
16					Access Transmission and Energy
17					Markets Tariff, Attachment O-NSP)
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Schedule Page: 1061 Line No.: 1 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER17-1120-000

Schedule Page: 1061 Line No.: 7 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER18-1004-000

Schedule Page: 1061 Line No.: 13 Column: d

Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin under ER19-1310-000

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	111	Comp Balance Sheet Assets and Other Defrd Debits	(c)	57
2	204-207	Electric Plant in Service (Acct 101 - 103, 106)	(g)	5, 46, 58, 75, 99
3	214	Electric Plant Held for Future Use (Acct 105)	(d)	46
4	216.1	Construction Work in Progress- Electric (Acct 107)	(b)	41
5	219	Accum Prov for Depr- Elec Utility Plant (Acct 108)	(c)	20-26, 28
6	227	Materials and Supplies	(a)	18
7	232	Other Regulatory Assets	(f)	12
8	234	Accumulated Deferred Income Taxes (Acct 190)	(c)	8
9	267	Accum. Deferred Investment Tax Credits (Acct 225)	(h)	8
10	269	Other Deferred Credits (Acct 253)	(d), (e)	35
11	269	Other Deferred Credits (Acct 253)	(a)	42
12	273	Accumulated Deferred Income Taxes (Acct 281)	(k)	8
13	275	Accumulated Deferred Income Taxes (Acct 282)	(k)	2
14	277	Accumulated Deferred Income Taxes (Acct 283)	(k)	3
15	278	Other Regulatory Liabilities	(f)	29
16	300	Electric Operating Revenues (Acct 400)	(b)	19
17	310.2	Sales for Resale (Acct 447)	(a)	5
18	321	Electric Operation and Maintenance Expenses	(b)	112
19	328	Transmission of Electricity for Others	(a)	19
20	356.2	Common Utility Plant and Expenses	n/a	n/a
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

The following important changes have been accumulated to date as of Q4 2018:

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

City	State	Utility	Expiration
Vadnais Heights	Minn.	Electric	Jan. 1, 2038
Vadnais Heights	Minn.	Gas	Jan. 1, 2038
White Bear Lake	Minn.	Electric	Jan. 8, 2038
White Bear Lake	Minn.	Gas	Jan. 8, 2038
Reile's Acres	N.D.	Gas	Jan. 8, 2038
Villard	Minn.	Electric	Feb. 12, 2038
Dilworth	Minn.	Electric	Feb. 25, 2038
Dilworth	Minn.	Gas	Feb. 25, 2038
North Branch	Minn.	Electric	April 9, 2038
North Branch	Minn.	Gas	April 9, 2038
Minnetonka	Minn.	Electric	May 14, 2038
Clearwater	Minn.	Gas	May 13, 2038
Fifty Lakes	Minn.	Gas	May 7, 2038
Shorewood	Minn.	Electric	June 23, 2038
Falcon Heights	Minn.	Electric	June 12, 2038
Falcon Heights	Minn.	Gas	June 12, 2038
Long Lake	Minn.	Electric	July 1, 2038
Norwood Young America	Minn.	Electric	Aug. 26, 2038
Lake Shore	Minn.	Gas	Sept. 23, 2038
Manhattan Beach	Minn.	Gas	Nov. 6, 2038
Crosslake	Minn.	Gas	Nov. 12, 2038
North St. Paul	Minn.	Gas	Nov. 19, 2038

2. Acquisitions

None

3. Purchase or sale of an operating unit or system

On Aug. 28, 2017, NSP-Minnesota filed a Section 203 application with FERC (Docket No. EC17-166-000) under which Benson Power, LLC ("Benson Power") would sell and NSP-Minnesota would acquire a 62.3 MW (nameplate) biomass-fired electric generation plant, terminate a multi-year Power Purchase Agreement between NSP-Minnesota and Benson Power, and then shut down and dismantle the Benson Power Facility and remediate the plant site. The transaction was approved by the Commission on Feb. 23, 2018, and on June 29, 2018 the transaction with Benson Power closed. NSP-Minnesota filed journal entries with the Commission on Dec. 21, 2018 in Docket No. AC19-53-000 in accordance with the order authorizing the transaction.

4. Important leaseholds acquired or given, assigned or surrendered

None

5. Important extension or reduction of transmission or distribution system

None

6. Obligations incurred as a result of securities or assumption of liabilities

See Note 5 of the Financial Statements on Page 123 for disclosures regarding short-term borrowings, long-term debt and other financing activities.

7. Changes in articles of incorporation and amendments to charter

None

8. Wage scale changes

Union Employees – 2.5 percent increase effective Jan. 1, 2018.

Non-Union Employees – Base pay cycle increase of 3.00 percent effective March 16, 2018**.**

9. Legal proceedings

See Note 9 of the Financial Statements on page 123 for disclosures regarding material legal proceedings.

10. Other materially important transactions with associates

None

11. (Reserved)

12. Important changes

None

13. Changes in officers, directors, major security holders and voting powers

Effective March 1, 2018, Marvin E. McDaniel, Jr. resigned as Executive Vice President, Group President of Utilities and Chief Administrative Officer.

Effective March 1, 2018, David L. Eves, was elected Executive Vice President and Group President of Utilities.

Effective May 7, 2018, Darla Figoli was elected Senior Vice President, Chief Human Resource Officer.

Effective Sept. 1, 2018, Brian Van Abel resigned as Vice President, Treasurer and was elected Senior Vice President of Finance and Corporate Development.

Effective Sept. 1, 2018, Sarah W. Soong was elected as Vice President, Treasurer.

14. Cash management programs

Not applicable as proprietary capital ratio is greater than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	20,215,132,001	19,299,054,693
3	Construction Work in Progress (107)	200-201	620,506,562	529,931,771
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		20,835,638,563	19,828,986,464
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	8,242,987,294	7,766,026,424
6	Net Utility Plant (Enter Total of line 4 less 5)		12,592,651,269	12,062,960,040
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	173,320,835	182,412,823
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		552,979,366	535,339,673
10	Spent Nuclear Fuel (120.4)		2,044,100,379	1,979,659,426
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	2,416,886,208	2,294,997,690
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		353,514,372	402,414,232
14	Net Utility Plant (Enter Total of lines 6 and 13)		12,946,165,641	12,465,374,272
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		9,702,989	13,785,198
19	(Less) Accum. Prov. for Depr. and Amort. (122)		9,224,397	12,240,557
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,518,302	2,446,176
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		52,504,848	49,062,277
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		2,054,708,655	2,143,532,093
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		17,038,034	28,102,000
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,127,248,431	2,224,687,187
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,338,625	12,406,411
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		122,380	122,380
38	Temporary Cash Investments (136)		42,292,116	31,155,929
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		360,475,225	327,940,750
41	Other Accounts Receivable (143)		44,024,894	47,916,248
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		23,452,404	21,278,289
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		12,151,713	48,494,400
45	Fuel Stock (151)	227	90,364,543	97,129,106
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	175,243,410	208,454,636
49	Merchandise (155)	227	1,094,063	752,710
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	28,206

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		29,511,024	27,153,915
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		3,194,683	4,193,243
57	Prepayments (165)		22,914,668	108,201,247
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	28,492
60	Rents Receivable (172)		730,856	714,254
61	Accrued Utility Revenues (173)		270,264,268	277,715,906
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		42,846,565	53,224,887
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		17,038,034	28,102,000
65	Derivative Instrument Assets - Hedges (176)		0	107,246
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,062,078,595	1,196,359,677
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		42,195,057	45,246,916
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	106,326,485	61,711,558
72	Other Regulatory Assets (182.3)	232	3,733,740,125	3,562,449,742
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,550	425,348
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	40,891,771	46,922,173
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		17,590,485	19,797,204
82	Accumulated Deferred Income Taxes (190)	234	793,034,294	783,099,188
83	Unrecovered Purchased Gas Costs (191)		18,245,464	22,322,051
84	Total Deferred Debits (lines 69 through 83)		4,752,027,231	4,541,974,180
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		20,887,519,898	20,428,395,316

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

Prepayments (Account No. 165). The Form 1 reports prepayments at the total Company level, at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of the year prepayments balance in the formula. In addition, since prepayments are reported in the Form 1 at the total Company level, they are allocated to the electric utility based on the ratio of electric net plant to the sum of electric and gas net plant as reported in the Form 1, page 200. The formula allocates the electric prepayments to the transmission function using a gross plant allocator.

NSP-Minnesota's Prepayments (Account No. 165) balance at Dec. 31, 2018, includes $2,677 for state income taxes. This balance was largely driven by a reserve for Wisconsin audits.

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

NSP-Minnesota's Prepayments (Account No. 165) balance at Dec. 31, 2017, includes $79,089,342 for income taxes. This balance was largely driven by an overpayment for 2017 income taxes, and a reserve for the Internal Revenue Service audits, a portion of which is currently in Appeals. NSP-Minnesota's overpayment for 2017 was settled in 2018 after the Xcel Energy extensions and tax returns were filed.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	04/18/2019	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	10,000	10,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		479,282,529	479,282,529
7	Other Paid-In Capital (208-211)	253	3,144,966,526	3,100,951,102
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,975,014,783	1,922,799,303
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-3,014,557	-2,936,745
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-23,100,565	-24,536,486
16	Total Proprietary Capital (lines 2 through 15)		5,573,158,716	5,475,569,703
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	5,000,000,000	5,000,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	9,208	35,044
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		20,644,869	21,770,166
24	Total Long-Term Debt (lines 18 through 23)		4,979,364,339	4,978,264,878
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		650,000	776,242
29	Accumulated Provision for Pensions and Benefits (228.3)		265,220,000	291,586,000
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		12,495,198	15,076,073
32	Long-Term Portion of Derivative Instrument Liabilities		112,165,303	102,741,828
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,177,887,158	2,083,873,501
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,568,417,659	2,494,053,644
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		150,000,000	20,000,000
38	Accounts Payable (232)		424,743,931	400,979,008
39	Notes Payable to Associated Companies (233)		1,450,000	86,450,000
40	Accounts Payable to Associated Companies (234)		110,678,085	82,278,729
41	Customer Deposits (235)		53,718,047	95,368,970
42	Taxes Accrued (236)	262-263	226,727,805	225,009,647
43	Interest Accrued (237)		65,915,275	65,404,903
44	Dividends Declared (238)		82,746,125	98,687,400
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		30,736,948	27,483,549
48	Miscellaneous Current and Accrued Liabilities (242)		41,744,471	29,766,915
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		128,645,253	120,439,254
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		112,165,303	102,741,828
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,204,940,637	1,149,126,547
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		13,745,986	13,979,506
57	Accumulated Deferred Investment Tax Credits (255)	266-267	21,103,317	22,527,604
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	385,835,916	325,443,020
60	Other Regulatory Liabilities (254)	278	3,672,887,991	3,578,757,196
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	28,895,301	30,841,977
63	Accum. Deferred Income Taxes-Other Property (282)		2,142,735,228	2,112,724,223
64	Accum. Deferred Income Taxes-Other (283)		296,434,808	247,107,018
65	Total Deferred Credits (lines 56 through 64)		6,561,638,547	6,331,380,544
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		20,887,519,898	20,428,395,316

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,081,006,064	4,951,746,389		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,094,259,618	2,939,483,149		
5	Maintenance Expenses (402)	320-323	266,599,697	245,544,721		
6	Depreciation Expense (403)	336-337	615,420,821	600,009,273		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-20,578,572	18,214,959		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	66,981,646	54,804,320		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		5,611,685	3,781,885		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		100,577,135	60,170,809		
13	(Less) Regulatory Credits (407.4)		114,043,483	211,280,280		
14	Taxes Other Than Income Taxes (408.1)	262-263	257,502,968	254,892,511		
15	Income Taxes - Federal (409.1)	262-263	-10,243,165	12,922,632		
16	- Other (409.1)	262-263	10,529,309	11,128,872		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	396,415,383	642,433,406		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	368,704,355	474,936,373		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,424,287	-1,647,628		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		4,380,113	6,365,726		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		103,287,110	121,988,404		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,397,811,397	4,271,144,934		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		683,194,667	680,601,455		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
4,495,459,910	4,430,077,743	585,546,154	521,668,646			2
						3
2,635,598,688	2,533,439,819	458,660,930	406,043,330			4
256,882,995	237,023,256	9,716,702	8,521,465			5
578,296,877	555,886,845	37,123,944	44,122,428			6
-20,958,982	17,904,087	380,410	310,872			7
62,262,405	49,785,532	4,719,241	5,018,788			8
						9
5,611,685	3,781,885					10
						11
100,386,401	60,170,809	190,734				12
107,031,616	193,664,890	7,011,867	17,615,390			13
237,176,590	232,574,892	20,326,378	22,317,619			14
-14,206,390	12,190,826	3,963,225	731,806			15
8,120,814	10,799,183	2,408,495	329,689			16
372,652,811	597,898,132	23,762,572	44,535,274			17
348,856,318	439,607,719	19,848,037	35,328,654			18
-1,316,708	-1,383,956	-107,579	-263,672			19
						20
						21
4,380,113	6,365,726					22
						23
101,516,463	120,514,242	1,770,647	1,474,162			24
3,861,755,602	3,790,947,217	536,055,795	480,197,717			25
633,704,308	639,130,526	49,490,359	41,470,929			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		683,194,667	680,601,455		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		30,740,899	28,334,432		
34	(Less) Expenses of Nonutility Operations (417.1)		23,962,681	21,566,837		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-77,812	-126,890		
37	Interest and Dividend Income (419)		2,466,244	4,307,708		
38	Allowance for Other Funds Used During Construction (419.1)		24,141,506	29,513,860		
39	Miscellaneous Nonoperating Income (421)		2,744,773	3,421,667		
40	Gain on Disposition of Property (421.1)		1,067,047	1,161,437		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		37,119,976	45,045,377		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		652,815	38,999		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		8,407,716	2,864,072		
46	Life Insurance (426.2)		-2,015,174	-2,933,511		
47	Penalties (426.3)		-33,489	98,501		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,652,354	2,762,332		
49	Other Deductions (426.5)		2,645,966	2,627,599		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		11,310,188	5,457,992		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	177,113	198,503		
53	Income Taxes-Federal (409.2)	262-263	-5,317,769	4,527,490		
54	Income Taxes-Other (409.2)	262-263	-5,052,714	4,662,787		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	33,570,790	20,103,254		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	22,571,570	19,491,836		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		805,850	10,000,198		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		25,003,938	29,587,187		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		215,646,430	220,363,148		
63	Amort. of Debt Disc. and Expense (428)		4,202,574	4,326,415		
64	Amortization of Loss on Reaquired Debt (428.1)		2,206,720	1,999,600		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		1,751,904	1,124,353		
68	Other Interest Expense (431)		4,582,028	7,308,402		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		12,526,182	15,054,582		
70	Net Interest Charges (Total of lines 62 thru 69)		215,863,474	220,067,336		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		492,335,131	490,121,306		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		492,335,131	490,121,306		

Schedule Page: 114 Line No.: 12 Column: c

	Electric	Gas
Minnesota Incentive Compensation Refund	$ 5,257,622	$ -
Minnesota Property Tax Amortization	8,180,122	-
Minnesota Renewable Development Fund	33,977,458	-
Minnesota Revenue Decoupling Mechanism	33,511,962	-
Minnesota State Energy Policy	-	190,734
Minnesota Transmission Cost Recovery	6,037,376	-
North Dakota Transmission Cost Recovery	1,476,081	-
Private Fuel Storage	2,641	-
Sherco Unit 3 Depreciation Deferral	667,355	-
South Dakota Infrastructure	309,549	-
South Dakota Transmission Cost Recovery	293,211	-
Theoretical Depreciation Reserve Surplus	10,673,024	-
	$100,386,401	$ 190,734

Schedule Page: 114 Line No.: 12 Column: d

	Electric	Gas
Minnesota Renewable Development Fund	$ 31,186,735	
Minnesota Renewable Energy Standard	9,680,536	
North Dakota Renewable Energy Rider	528,818	
North Dakota Transmission Cost Recovery	786,206	
Private Fuel Storage	57,795	
Sherco Unit 3 Depreciation Deferral	439,464	
South Dakota Infrastructure	529,020	
South Dakota Production Tax Credit	6,214,326	
South Dakota Transmission Cost Recovery	1,341,476	
Theoretical Depreciation Reserve Surplus	9,406,433	
	$ 60,170,809	

Schedule Page: 114 Line No.: 13 Column: c

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	$ 80,557,481	$2,151,056
LED Streetlighting	220,567	-
Minnesota Gas Utility Infrastructure	-	4,860,811
Minnesota Renewable Energy Standard	9,540,098	-
Minnesota Sales True Up	15,763,259	-
North Dakota Renewable Energy Rider	870,105	-
Transco Amortization	80,106	-
	$107,031,616	$7,011,867

Schedule Page: 114 Line No.: 13 Column: d

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	$ 138,418,327	$ 1,785,035
LED Streetlighting	686,612	
Minnesota Gas Utility Infrastructure		15,495,696
Minnesota Revenue Decoupling Mechanism	28,008,662	
Minnesota Sales True Up	22,667,433	
Minnesota State Energy Policy		334,659
Minnesota Transmission Cost Recovery	3,830,452	
Transco Amortization	53,404	
	$ 193,664,890	$ 17,615,390

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

Income on Company Owned Life Insurance.

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

Income on Company Owned Life Insurance.

Schedule Page: 114 Line No.: 47 Column: c

Credit balance due to accrual reversal.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,922,721,680	1,943,978,203
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Reclassification of Tax Effects from Account 219	219	-2,363	4,348,780
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-2,363	4,348,780
10				
11	Rounding			1
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			1
16	Balance Transferred from Income (Account 433 less Account 418.1)		492,412,943	490,248,196
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-440,195,100	(515,853,500)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-440,195,100	(515,853,500)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,974,937,160	1,922,721,680
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		77,623	77,623
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		77,623	77,623
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,975,014,783	1,922,799,303
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,936,745	(2,809,856)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-77,812	(126,890)
51	(Less) Dividends Received (Debit)			
52	Rounding			1
53	Balance-End of Year (Total lines 49 thru 52)		-3,014,557	(2,936,745)

Schedule Page: 118   Line No.: 4   Column: b

On November 15, 2018 the FERC granted Edison Electric Institute's request for blanket approval for public utilities and centralized service companies to use Account 439 to record reclassifications of "accumulated other comprehensive income" to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act (Docket No. AC18-59-000).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	492,335,131	490,121,306
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	739,476,355	677,293,963
5	Amortization of Nuclear Fuel	121,888,518	114,361,824
6	Amortization of Premium, Discount and Debt Expense	6,409,294	6,326,015
7	Gain on Disposition of Property	-1,038,017	-1,122,438
8	Deferred Income Taxes (Net)	38,710,248	168,108,451
9	Investment Tax Credit Adjustment (Net)	-1,424,287	-1,647,628
10	Net (Increase) Decrease in Receivables	-18,411,660	17,807,675
11	Net (Increase) Decrease in Inventory	-21,460,083	7,665,691
12	Net (Increase) Decrease in Allowances Inventory	28,206	-24,139
13	Net Increase (Decrease) in Payables and Accrued Expenses	19,512,905	53,211,626
14	Net (Increase) Decrease in Other Regulatory Assets	47,770,430	-141,163,039
15	Net Increase (Decrease) in Other Regulatory Liabilities	137,538,695	113,170,120
16	(Less) Allowance for Other Funds Used During Construction	23,843,506	29,513,860
17	(Less) Undistributed Earnings from Subsidiary Companies	-77,812	-126,889
18	Other: (Increase) Decrease in Accrued Utility Revenues	7,451,638	-18,125,445
19	Other: Net Realized and Unrealized Hedging and Derivative Transactions	26,980,555	-2,783,828
20	Other: Changes in Other Current Assets and Liabilities	46,056,733	-70,718,178
21	Other: Changes in Noncurrent Liabilities and Deferred Amounts	-130,892,220	-110,353,183
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,487,166,747	1,272,741,822
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,012,808,420	-738,665,574
27	Gross Additions to Nuclear Fuel	-72,988,658	-125,641,770
28	Gross Additions to Common Utility Plant	-93,075,885	-152,375,366
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-23,843,506	-29,513,860
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,155,029,457	-987,168,850
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Investments in Utility Money Pool Arrangement	-805,000,000	-122,000,000
44	Purchase of Investment Securities (a)		-1,248,712
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Repayments from Utility Money Pool Arrangement	805,000,000	122,000,000
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Miscellaneous Other Investing Activities	-3,442,571	-3,516,327
54	Other: Purchase of Investments in External Decommissioning Fund	-852,939,312	-1,689,281,473
55	Other: Proceeds from Sale of Investments in External Decommissioning	832,817,511	1,668,909,725
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,178,593,829	-1,012,305,637
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		585,247,832
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions by Parent	108,751,434	145,003,018
65	Other: Borrowings under Utility Money Pool Arrangement	479,000,000	838,000,000
66	Net Increase in Short-Term Debt (c)	130,000,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	717,751,434	1,568,250,850
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-25,835	-507,865,363
74	Preferred Stock		
75	Common Stock		
76	Other: Repayments under Utility Money Pool Arrangement	-564,000,000	-753,000,000
77	Other: Miscellaneous Other Financing Activities	-93,741	
78	Net Decrease in Short-Term Debt (c)		-65,000,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-456,136,375	-506,594,250
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-302,504,517	-264,208,763
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	6,068,401	-3,772,578
87			
88	Cash and Cash Equivalents at Beginning of Period	43,684,720	47,457,298
89			
90	Cash and Cash Equivalents at End of period	49,753,121	43,684,720

Schedule Page: 120 Line No.: 21 Column: b

Changes in Noncurrent Liabilities and Deferred Amounts		
Change in pension and employee benefit obligation	$	(76,320,539)
Change in deferred debits		10,284,557
Change in deferred credits		(62,149,121)
Change in noncurrent liabilities		(2,707,117)
	$	(130,892,220)

Schedule Page: 120 Line No.: 21 Column: c

Changes in Noncurrent Liabilities and Deferred Amounts		
Change in pension and employee benefit obligation	$	(58,417,849)
Change in deferred debits		26,411,218
Change in deferred credits		(49,738,233)
Change in noncurrent liabilities		(28,608,319)
	$	(110,353,183)

Schedule Page: 120 Line No.: 90 Column: b

Cash and Working Funds (130)	$	0
Cash (131)		7,338,625
Working Fund (135)		122,380
Temporary Cash Investments (136)		42,292,116
Cash and Cash Equivalents at End of Period	$	49,753,121

Schedule Page: 120 Line No.: 90 Column: c

Cash and Working Funds (130)	$	0
Cash (131)		12,406,411
Working Fund (135)		122,380
Temporary Cash Investments (136)		31,155,929
Cash and Cash Equivalents at End of Period	$	43,684,720

NOTES TO FINANCIAL STATEMENTS

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

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

1. Summary of Significant Accounting Policies

Business and System of Accounts — Northern States Power Co., a Minnesota corporation (NSP-Minnesota) is engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. NSP-Minnesota is subject to regulation by the Federal Energy Regulatory Commission (FERC) and state utility commissions.

The electric production and transmission system of NSP-Minnesota and Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin), (collectively, NSP System) is operated on an integrated basis and managed by NSP-Minnesota and NSP-Wisconsin. The electric production and transmission costs of the NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

Effective Jan. 1, 2018, NSP-Minnesota and NSP-Wisconsin changed its method of accounting for transmission related Interchange Agreement billings. NSP-Minnesota and NSP-Wisconsin historically had recorded the monthly transmission billings to each other in Account 456 and transmission related payments to each other in Account 566. To consistently account for the transmission related Interchange Agreement billings used for revenues and expenses from Midcontinent Independent System Operator, Inc. (MISO) and other third-parties' use of the NSP System transmission facilities, NSP-Minnesota and NSP-Wisconsin began recording the monthly transmission billings to each other in Account 456.1 and the transmission related payments to each other in Account 565 (see Docket No. AC18-55-000).

Basis of Accounting — The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation within the utility plant accounts in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP, while for the FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income and deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.

- Income tax expense related to utility operations is shown as a component of utility operating expenses in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.

- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.

- The setup of theoretical excess depreciation reserves was recorded as a regulatory asset and an increase to regulatory credits for FERC presentation, in contrast to a reduction to both accumulated depreciation and depreciation expense for GAAP presentation. The unwinding of the regulatory asset is recorded as an increase to regulatory debits for FERC presentation with an offsetting entry to depreciation expense and accumulated depreciation, resulting in no net impact to the balance sheet or income statement. Therefore, bringing FERC back into alignment with GAAP presentation over the average remaining life of the assets.

- Deferred financing costs are included as deferred debits in the FERC presentation, while GAAP presentation includes them with long-term liabilities.

- Non-service cost components of net periodic benefit costs that are reported on the income statement are recorded as operation expenses in the FERC presentation and as other income, net for GAAP presentation. Non-service costs that are eligible for capitalization are recorded as a component of net utility plant in the FERC presentation and as regulatory assets for GAAP.

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

(Millions of Dollars)		
Balance Sheet:		
Net utility plant	$	595.5
Current assets		284.5
Current liabilities		315.8
Other long-term assets		(3,297.6)
Long-term debt and other long-term liabilities		(2,733.3)
Statement of Income:		
Operating revenues	$	40.9
Operating expenses		7.6
Other income and deductions		(7.7)
Interest Charges		(1.6)
Statement of Cash Flows:		
Cash provided by operating activities	$	(5.0)
Cash used in investing activities		5.1
Cash provided by financing activities		—

Use of Estimates — NSP-Minnesota uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used on items such as plant depreciable lives or potential disallowances, asset retirement obligations (ARO), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results.

Regulatory Accounting — NSP-Minnesota accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and

- Certain credits, which would otherwise be reflected as income or other comprehensive income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment, and may be required to eliminate regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota's results of operations, financial condition and cash flows.

See Note 3 for further information.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. NSP-Minnesota defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Minnesota uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

The effects of NSP-Minnesota's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability which will be refundable to utility customers over the remaining life of the related assets. A tax rate increase would result in the establishment of a similar regulatory asset.

Reversal of certain temporary differences are accounted for as current income tax expense due to the effects of past regulatory practices, when deferred taxes were not required to be recorded due to the use of flow through accounting for ratemaking purposes. Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize it over the book depreciable lives of the related property. The requirement to defer and amortize tax credits only applies to federal investment tax credits (ITCs) related to public utility property. Utility rate regulation also has resulted in the recognition of regulatory assets and liabilities related to income taxes.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

NSP-Minnesota follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. NSP-Minnesota recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position.

Recognition of changes in uncertain tax positions are reflected as a component of income tax.

Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including NSP-Minnesota, file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 6 for further information.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred.

Maintenance and replacement of items determined to be less than a unit of property are charged to operating expenses as incurred. Planned maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made.

For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

NSP-Minnesota records depreciation expense using the straight-line method over the plant's useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.6% for 2018 and 2017.

AROs — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset.

Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the amounts through the establishment of a regulatory asset and recovery in rates. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs.

See Note 9 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants are performed at least every three years and submitted to the state commissions for approval.

For ratemaking purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants over each facility's expected service life based on the triennial decommissioning studies filed with state commissions. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in nuclear decommissioning fund and deferred debits on the balance sheets.

See Notes 7 and 9 for further information.

Benefit Plans and Other Postretirement Benefits — NSP-Minnesota maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 8 for further information.

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

Estimated remediation costs are regularly adjusted as estimates are revised and remediation proceeds. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses.

See Note 9 for further information.

Revenue From Contracts With Customers — Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. NSP-Minnesota recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

NSP-Minnesota does not recognize a separate financing component of its collections from customers as contract terms are short-term in nature. NSP-Minnesota presents its revenues net of any excise or sales taxes or fees.

NSP-Minnesota participates in Midcontinent Independent System Operator, Inc. (MISO). NSP-Minnesota recognizes sales to both native load and other end use customers on a gross basis in electric revenues and cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through Regional Transmission Organizations (RTOs) are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon the total volumes. The real time and day-ahead market are each evaluated separately. If NSP-Minnesota is a net seller the transaction is recorded on a gross basis in electric revenues and cost of sales. If NSP-Minnesota is a net buyer, the transaction is recorded on a net basis in cost of sales.

Revenues and charges for energy transacted through MISO are recorded based upon our evaluation each hour as to whether we are a net seller or a net buyer based upon the total volumes. The real time and day-ahead market are each evaluated separately. If NSP-Minnesota is a net seller the transaction is recorded on a gross basis in electric revenues and cost of sales. If NSP-Minnesota is a net buyer the transaction is recorded on a net basis in cost of sales.

NSP-Minnesota has various rate-adjustment mechanisms that provide for the recovery of natural gas, electric fuel and purchased energy costs. Cost-adjustment tariffs may increase or decrease the level of revenue collected from customers and are revised periodically for differences between the total amount collected under the clauses and the costs incurred.

When applicable, fuel cost over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as regulatory assets.

Cash and Cash Equivalents — NSP-Minnesota considers investments in instruments with a remaining maturity of 3 months or less at the time of purchase, to be cash equivalents.

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

Inventory — Inventory is recorded at average cost.

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values (NAVs).

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, NSP-Minnesota may use quoted prices for similar contracts or internally prepared valuation models to determine fair value.

For the pension and postretirement plan assets and nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each security.

See Notes 8 and 9 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price and commodity trading activities, including forward contracts, futures, swaps and options. Any derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues; hedging transactions for vehicle fuel costs are recorded as a component of capital projects and operating expenses; and interest rate hedging transactions are recorded as a component of interest expense.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for purchases and sales of commodities for use in its operations. At inception, contracts are evaluated to determine whether a derivative exists and/or whether an instrument may be exempted from derivative accounting if designated as a normal purchase or normal sale.

See Note 7 for further information.

Commodity Trading Operations — Pursuant to the joint operating agreement (JOA) approved by the FERC, some of the commodity trading margins from Public Service Company of Colorado (PSCo) are apportioned to NSP-Minnesota and Southwestern Public Service Company (SPS). Commodity trading activities are not associated with energy produced from PSCo's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. See Note 7 for further discussion.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base for establishing utility rates.

Alternative Revenue — Certain rate rider mechanisms (including decoupling and conservation improvement programs (CIP)) qualify as alternative revenue programs under GAAP. These mechanisms arise from costs imposed upon the utility by action of a regulator or legislative body related to an environmental, public safety or other mandate. When certain criteria are met, such as collection within 24 months, revenue is recognized equal to the revenue requirement, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between the total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers in the period earned.

Conservation Programs — Costs incurred for CIP programs are deferred if it is probable future revenue will recover the incurred cost. Revenues recognized for incentive programs for the recovery of lost margins and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from when they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emission Allowances — Emission allowances are recorded at cost plus broker commission fees. The inventory accounting model is utilized for all emission allowances and sales of these allowances are included in electric revenues.

Nuclear Refueling Outage Costs — NSP-Minnesota uses a deferral and amortization method for nuclear refueling costs. This method amortizes refueling outage costs over the period between refueling outages consistent with rate recovery.

Renewable Energy Credits (RECs) — Cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. Sales of RECs are recorded in electric revenues on a gross basis. The cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2018 up to Feb. 22, 2019, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 18, 2019. These financial statements contain all necessary adjustments and disclosures resulting from these evaluations.

2. Investments Accounted for by the Equity Method

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

Name	Geographic Area	Economic Interest
United Power & Land	United States	100%
NSP-Nuclear Corp.	United States	100%
Private Fuel Storage, LLC*	United States	32.8%

*The investment in Private Fuel Storage, LLC has been written down to zero.

Summarized Financial Information of Unconsolidated Investees:

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

(Millions of Dollars)	2018	2017
Current assets	1.7	1.6
Other assets	1.0	1.0
Total assets	2.7	2.6
Current liabilities	0.2	0.1
Other liabilities	0.0	-
Equity	2.5	2.5
Total liabilities and equity	2.7	2.6

(Millions of Dollars)	2018	2017
Operating revenues	0.0	0.0
Operating loss	(0.1)	(0.2)
Net Loss	(0.1)	(0.1)

3. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in net income or other comprehensive income if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Regulatory Assets		
Asset retirement recovery	2,238.9	2,156.2
Pension and retiree medical obligations	447.4	432.2
Theoretical deprecation reserve surplus	267.8	278.5
Excess deferred taxes - TCJA	153.3	133.1
Recoverable deferred taxes on AFUDC recorded in plant	117.6	119.0
Purchased power agreement (PPA) termination	92.2	
Contract valuation adjustments (a)	90.1	104.2
Nuclear refueling outage costs	50.2	69.0
Renewable resources and environmental initiatives	41.7	47.6
Purchased power contracts costs	39.3	41.1
Conservation programs (b)	27.3	31.6
Environmental remediation costs	15.5	24.6
Sherco Unit 3 Deferral	8.1	8.7
Other	144.3	116.7
Other regulatory assets	3,733.7	3,562.5

(a) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Regulatory Liabilities		
Plant removal costs	1,623.0	1,564.4
Deferred income tax adjustments and TCJA refunds (a)	1,562.2	1,460.2
Investments	292.4	398.7
Excess deferred taxes - TCJA	51.3	55.9
Investment tax credit deferrals (b)	16.5	15.4
United States Department of Energy (DOE) Settlement	11.4	11.2
Contract valuation adjustments (c)	10.4	17.2
Deferred electric energy costs	22.8	11.7
Other	82.9	44.1
Other regulatory liabilities (d)	3,672.9	3,578.8

(a) Includes the revaluation of recoverable/regulated plant ADIT and revaluation impact of non-plant ADIT due to the TCJA.
(b) Includes impact of lower federal tax rate due to the TCJA.
(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
(d) Revenue is subject for refund of $12.5 million and $15.1 million for 2018 and 2017, respectively, is included in other current liabilities.

At Dec. 31, 2018 and 2017, approximately $149 million and $142 million, respectively, of NSP-Minnesota's regulatory assets represented past expenditures not earning a return. Amounts primarily related to purchased natural gas and electric energy costs and certain expenditures associated with pension.

4. Joint Ownership of Generation and Transmission Facilities

Jointly owned assets as of Dec. 31, 2018:

(Millions of Dollars)	Plant in Service	Accumulated Depreciation (a)	CWIP	Percent Owned
Electric Generation:				
Sherco Unit 3	$ 604.2	$ 415.0	$ 1.0	59 %
Sherco Common Facilities	145.4	100.2	1.2	80
Other	4.8	3.4	—	59
Electric Transmission:				
CapX2020 Transmission	959.6	72.7	1.9	51
Other	10.6	2.3	—	50
Total	$ 1,724.6	$ 593.6	$ 4.1	

(a) ARO is not included.

NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. Money pool borrowings for NSP-Minnesota were as follows:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017
Borrowing limit	$ 250	$ 250
Amount outstanding at period end	—	85
Average amount outstanding	17	25
Maximum amount outstanding	143	142
Weighted average interest rate, computed on a daily basis	1.96 %	1.14 %
Weighted average interest rate at period end	N/A	1.18

Commercial Paper — NSP-Minnesota meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility.

Commercial paper outstanding for NSP-Minnesota was as follows:

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017
Borrowing limit	$ 500	$ 500
Amount outstanding at period end	150	20
Average amount outstanding	38	62
Maximum amount outstanding	198	237
Weighted average interest rate, computed on a daily basis	2.08 %	1.10 %
Weighted average interest rate at end of period	2.97	1.93

Letters of Credit — NSP-Minnesota uses letters of credit, typically with terms of one-year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2018 and 2017, there were $37 million and $24 million of letters of credit outstanding, respectively, under the credit facility. Amounts approximate their fair value.

Credit Facility — NSP-Minnesota must have a revolving credit facility in place at least equal to the amount of its commercial paper borrowing limit and cannot issue commercial paper in an amount exceeding available capacity under this credit facility. The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

Features of NSP-Minnesota's credit facility:

Debt-to-Total Capitalization Ratio [a] 2018	Debt-to-Total Capitalization Ratio [a] 2017	Amount Facility May Be Increased (millions)	Additional Periods For Which a One-Year Extension May Be Requested [b]
48%	48%	$ 100	2

[a] The credit facility has a financial covenant requiring that the debt-to-total capitalization ratio be less than or equal to 65%.
[b] All extension requests are subject to majority bank group approval.

The credit facility has a cross-default provision that NSP-Minnesota will be in default on its borrowings under the facility if it or any of its subsidiaries whose total assets exceed 15% of NSP-Minnesota's total assets, default on indebtedness in an aggregate principal amount exceeding $75 million.

If NSP-Minnesota does not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender. As of Dec. 31, 2018, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

NSP-Minnesota had the following committed credit facilities available as of Dec. 31, 2018 (in millions):

Credit Facility [(a)]	Drawn [(b)]	Available
$ 500	$ 187	$ 313

(a) This credit facility matures in June 2021 .
(b) Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the credit facility. NSP-Minnesota had no direct advances on the facility outstanding at Dec. 31, 2018 and 2017.

Long-Term Borrowings and Other Financing Instruments

Generally, all property of NSP-Minnesota is subject to the lien of its first mortgage indenture. Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses for refinanced debt are deferred and amortized over the life of the new issuance.

Long term debt obligations for NSP-Minnesota as of Dec. 31:

(Millions of Dollars)	Maturity Range	Interest Rate Range 2018	Interest Rate Range 2017	2018	2017
NSP-Minnesota					
Mortgage bonds	2020-2047	2.15% - 7.13%	2.15% - 7.13%	$ 5,000	$ 5,000
Unamortized discount				(21)	(22)
Unamortized debt issuance cost				(42)	(45)
Current maturities				—	—
Total				$ 4,937	$ 4,933

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2019	$ —
2020	300
2021	—
2022	300
2023	400

During 2018, NSP-Minnesota did not complete any new financings.

2017 financings:

	Amount	Financing Instrument	Interest Rate	Maturity Date
NSP-Minnesota	600 million	First mortgage bonds	3.60 %	Sept. 15, 2047

Deferred Financing Costs — Deferred financing costs of approximately $42 million and $45 million, net of amortization, are presented as a deduction from the carrying amount of long-term debt at Dec. 31, 2018 and 2017, respectively.

Dividend Restrictions — NSP-Minnesota's dividends are subject to the FERC's jurisdiction, which prohibits the payment of dividends out of capital accounts. Dividend payments are solely to be paid from retained earnings.

NSP-Minnesota's state regulatory commission imposes the most restrictive dividend limitations.

Requirements and actuals as of Dec. 31, 2018:

	Equity to Total Capitalization Ratio - Required Range		Equity to Total Capitalization Ratio - Actual
	Low	High	2018
NSP-Minnesota	47.1 %	57.5 %	52.3 %

	Unrestricted Retained Earnings	Total Capitalization	Limit on Total Capitalization
NSP-Minnesota	$ 1.0billion	$ 10.7billion	$ 11.5billion

6. Income Taxes

Federal Tax Reform — In 2017, the TCJA was signed into law. The key provisions impacting Xcel Energy (which includes NSP-Minnesota), generally beginning in 2018, include:

- Corporate federal tax rate reduction from 35% to 21%;
- Normalization of resulting plant-related excess deferred taxes;
- Elimination of the corporate alternative minimum tax;
- Continued interest expense deductibility and discontinued bonus depreciation for regulated public utilities;
- Limitations on certain executive compensation deductions;
- Limitations on certain deductions for net operating losses (NOLs) arising after Dec. 31, 2017 (limited to 80% of taxable income);
- Repeal of the section 199 manufacturing deduction; and,
- Reduced deductions for meals and entertainment as well as state and local lobbying.

Xcel Energy estimated the effects of the TCJA, which have been reflected in the financial statements.
Reductions in deferred tax assets and liabilities due to a decrease in corporate federal tax rates typically result in a net tax benefit. However, the impacts are primarily recognized as regulatory liabilities refundable to utility customers as a result of Internal Revenue Service (IRS) requirements and past regulatory treatment.

Estimated impacts of the new tax law for NSP-Minnesota in December 2017 included:

- $1.1 billion ($1.5 billion grossed-up for tax) of reclassifications of plant-related excess deferred taxes to regulatory liabilities upon valuation at the new 21% federal rate. The regulatory liabilities will be amortized consistent with IRS normalization requirements, resulting in customer refunds over the average remaining life of the related property;
- $133 million and $56 million of reclassifications (grossed-up for tax) of excess deferred taxes for non-plant related deferred tax assets and liabilities, respectively, to regulatory assets and liabilities; and
- $19 million of total estimated income tax expense related to the federal tax reform implementation, and a $5 million reduction to net income related to the allocation of Xcel Energy Services Inc.'s tax rate change on its deferred taxes.

Xcel Energy accounted for the state tax impacts of federal tax reform based on enacted state tax laws. Any future state tax law changes related to the TCJA will be accounted for in the periods state laws are enacted.

Federal Tax Loss Carryback Claims — In 2012 - 2015, Xcel Energy identified certain expenses related to 2009, 2010, 2011, 2013, 2014 and 2015 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $5 million in 2015, $17 million in 2014, $12 million in 2013 and $15 million in 2012.

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. Statute of limitations applicable to Xcel Energy's consolidated federal income tax returns expire as follows:

Tax Year(s)	Expiration
2009 - 2014	October 2019
2015	September 2019
2016	September 2020
2017	September 2021

In 2012, the IRS commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. In 2017, Xcel Energy and the Office of Appeals reached an agreement and the benefit related to the agreed upon portions was recognized. In the second quarter of 2018, the Joint Committee on Taxation completed its review and took no exception to the agreement. As a result, the remaining unrecognized tax benefit was released and recorded as a payable to the IRS.

In the third quarter of 2015, the IRS commenced an examination of tax years 2012 and 2013. In the third quarter of 2017, the IRS concluded the audit of tax years 2012 and 2013 and proposed an adjustment that would impact Xcel Energy's NOL and effective tax rate (ETR). Xcel Energy filed a protest with the IRS. As of Dec. 31, 2018, the case has been forwarded to the Office of Appeals and Xcel Energy has recognized its best estimate of income tax expense that will result from a final resolution of this issue; however, the outcome and timing of a resolution is unknown.

In the fourth quarter of 2018, the IRS began an audit of tax years 2014 - 2016, however no adjustments have been proposed.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2018, NSP-Minnesota's earliest open tax year subject to examination by state taxing authorities under applicable statutes of limitations is 2009. In the fourth quarter of 2018, the Minnesota audit of tax years 2010 - 2014 concluded with no material adjustments.

Unrecognized Tax Benefits — Unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain, but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority to an earlier period.

***Uncertainty in Income Taxes* -** The FERC has not fully adopted the guidance for uncertainty in income taxes. Accordingly, NSP-Minnesota has recorded its unrecognized tax benefits for temporary adjustments, including NOL and tax credit carryforwards, in accounts established for accumulated deferred income taxes.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
Unrecognized tax benefit — Permanent tax positions	$ 11.6	$ 10.2
Unrecognized tax benefit — Temporary tax positions	5.3	7.9
Total unrecognized tax benefit	$ 16.9	$ 18.1

Changes in unrecognized tax benefits:

(Millions of Dollars)	2018	2017
Balance at Jan. 1	$ 18.1	$ 60.8
Additions based on tax positions related to the current year	2.0	2.7
Reductions based on tax positions related to the current year	(0.3)	(1.7)
Additions for tax positions of prior years	0.6	5.7
Reductions for tax positions of prior years	(1.1)	(49.4)
Settlements with taxing authorities	(2.4)	—
Balance at Dec. 31	$ 16.9	$ 18.1

Unrecognized tax benefits were reduced by tax benefits associated with NOL and tax credit carryforwards:

(Millions of Dollars)	Dec. 31, 2018	Dec. 31, 2017
NOL and tax credit carryforwards	$ (12.7)	$ (12.8)

As the IRS Appeals and federal audit progress and state audits resume, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $13.7 million in the next 12 months.

Payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards.

Interest payable related to unrecognized tax benefits:

(Millions of Dollars)	2018	2017
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (0.9)	$ (2.0)
Interest (expense) income related to unrecognized tax benefits	(0.3)	1.1
Payable for interest related to unrecognized tax benefits at Dec. 31	$ (1.2)	$ (0.9)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2018 and 2017.

Other Income Tax Matters — NOL amounts represent the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2018	2017
Federal NOL carryforward	$ —	$ 638.2
Federal tax credit carryforwards	387.3	306.3
State NOL carryforwards	233.6	296.0
State tax credit carryforwards, net of federal detriment	89.2	91.7
Valuation allowances for state credit carryforwards, net of federal detriment	(78.5)	(82.2)

Federal carryforward periods expire between 2021 and 2038 and state carryforward periods expire between 2019 and 2035.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense.

Effective income tax rate for years ended Dec. 31:

	2018	2017 [(a)]
Federal statutory rate	21.0 %	35.0 %
State income tax on pretax income, net of federal tax effect	7.1	5.8
Increases (decreases) in tax from:		
Wind production tax credits (PTCs) recognized	(13.6)	(11.4)
Regulatory differences - ARAM [(b)]	(9.1)	(0.1)
Other tax credit recognized, net of federal income tax expense	(1.3)	(1.0)
Regulatory differences - other utility plant items	0.3	(0.2)
Tax reform	—	2.7
Other, net	0.8	(1.8)
Effective income tax rate	5.2 %	29.0 %

(a) Prior periods have been reclassified to conform to current year presentation.
(b) Average rate assumption method (ARAM) is a method to flow back excess deferred taxes to customers.

(Millions of Dollars)	2018	2017
Current federal tax (benefit) expense	$ (16.8)	$ 29.8
Current state tax expense	5.2	14.7
Current change in unrecognized tax expense (benefit)	1.5	(11.3)
Deferred federal tax (benefit) expense	(3.4)	121.5
Deferred state tax expense	42.1	46.6
Deferred ITCs	(1.4)	(1.6)
Total income tax expense	$ 27.2	$ 199.7

Components of deferred income tax expense as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax expense (benefit) excluding items below	$ 67.5	$ (1,201.5)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(28.2)	1,369.9
Tax expense allocated to other comprehensive income, net of adoption of ASU No. 2018-02, and other	(0.6)	(0.3)
Deferred tax expense	$ 38.7	$ 168.1

Components of the net deferred tax liability as of Dec. 31:

(Millions of Dollars)	2018	2017
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 2,597.4	$ 2,577.7
Regulatory assets	(204.1)	(259.4)
Pension expense	64.7	54.2
Other	10.1	18.2
Total deferred tax liabilities	$ 2,468.1	$ 2,390.7
Deferred tax assets:		
Differences between book and tax bases of property	$ 314.0	$ 304.5
Regulatory liabilities	(84.5)	(95.5)
Tax credit carryforward	476.5	315.9
NOL carryforward	18.9	156.5
Tax credit valuation allowances	(78.5)	—
Other employee benefits	38.6	37.3
Deferred ITCs	6.4	6.8
Rate refund	49.7	6.6
Other	51.9	51.0
Total deferred tax assets	$ 793.0	$ 783.1
Net deferred tax liability	$ 1,675.1	$ 1,607.6

In December 2017, NSP-Minnesota remeasured our deferred tax assets and liabilities to the new federal corporate income tax rate of 21%. After filing the 2017 tax return, we completed a final remeasurement of our 2017 deferred tax assets and liabilities to the new corporate tax rate. NSP- Minnesota received guidance from its jurisdictions in 2018 and started the amortization of the deficient and excess ADIT. The Protected ADITs, which are required by IRS normalization rules to be provided to customers, are amortized according to the rules of the Average Rate Assumption Method (ARAM) with amortization occurring over the remaining book life of the individual assets. The Unprotected ADITs, are amortized according to each jurisdiction. The Nonplant Unprotected have amortization periods ranging from 3-15 years. While, Plant Unprotected will use ARAM.

The amount of deficient and excess accumulated deferred income tax assets and liabilities that are considered protected and unprotected as of December 31, 2018 and 2017 is reflected below.

	Dec. 31, 2018		Dec. 31, 2017	
(Millions of dollars)	Account 182.3	Account 254	Account 182.3	Account 254
Protected				
Plant	0.0	1,232.5	0.0	1,261.4
Nonplant	119.5	0.0	101.8	0.0
Unprotected				
Plant	0.0	181.3	0.0	198.8
Nonplant	33.8	51.3	31.3	55.9
Total				
Plant	0.0	1,413.8	0.0	1,460.2
Nonplant	153.3	51.3	133.1	55.9

Excess and deficient accumulated deferred income taxes (ADITs) in 2018 were amortized in the Statement of Income as follows:

(Millions of dollars)	Dec. 31, 2018
Protected	
Plant	(32.8)
Nonplant	3.9
Unprotected	
Plant	(14.3)
Nonplant	(1.8)
Total	
Plant	(47.1)
Nonplant	2.1

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
- Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.
- Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted NAV.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds are measured using NAVs. The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled fund investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate commingled funds investments may be redeemed with proper notice, however, may be delayed or discounted as a result of fund illiquidity.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2 classification. When contractual settlements relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include transmission congestion instruments, generally referred to as financial transmission rights (FTRs). FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of transmission congestion. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of important inputs to the value of FTRs between auction processes, including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3.

Non-trading monthly FTR settlements are included in fuel and purchased energy cost recovery mechanisms, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs pertinent to the value of FTRs are insignificant to the financial statements of NSP-Minnesota.

Non-Derivative Fair Value Measurements

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning these facilities. The fund contains cash equivalents, debt securities, equity securities and other investments. NSP-Minnesota uses the Minnesota Public Utilities Commission (MPUC) approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning over the lives of the nuclear plants, assuming rate recovery of all costs. Realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund are deferred as a component of the regulatory asset.

Unrealized gains for the nuclear decommissioning fund were $450.1 million and $559.9 million as of Dec. 31, 2018 and 2017, respectively, and unrealized losses were $44.8 million and $7.4 million as of Dec. 31, 2018 and 2017, respectively.

Non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund:

	Dec. 31, 2018					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund						
Cash equivalents	$ 24.3	$ 24.3	$ —	$ —	$ —	$ 24.3
Commingled funds	758.1	79.2	—	—	819.1	$ 898.3
Debt securities	465.6	—	435.6	—	—	$ 435.6
Equity securities	401.4	696.5	—	—	—	$ 696.5
Total	$ 1,649.4	$ 800.0	$ 435.6	$ —	$ 819.1	$ 2,054.7

	Dec. 31, 2017					
		Fair Value				
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	NAV	Total
Nuclear decommissioning fund						
Cash equivalents	$ 28.7	$ 28.7	$ —	$ —	$ —	$ 28.7
Commingled funds	701.3	222.8	—	—	659.1	$ 881.9
Debt securities	437.7	—	441.6	—	—	$ 441.6
Equity securities	423.1	791.1	—	—	—	$ 791.1
Total	$ 1,590.8	$ 1,042.6	$ 441.6	$ —	$ 659.1	$ 2,143.3

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2018:

	Final Contractual Maturity				
(Millions of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Debt securities	$ 10.6	$ 106.9	$ 210.5	$ 107.6	$ 435.6

Rabbi Trusts

NSP-Minnesota has established a rabbi trust to provide partial funding for future deferred compensation plan distributions. Cost and fair value of assets held in rabbi trusts:

	December 31, 2018				
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 0.4	$ 0.4	$ —	$ —	$ 0.4
Mutual funds	10.8	10.7	—	—	10.7
Total	$ 11.2	$ 11.1	$ —	$ —	$ 11.1

		Dec. 31, 2017			
		Fair Value			
(Millions of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Rabbi Trusts [(a)]					
Cash equivalents	$ 0.8	$ 0.8	$ —	$ —	$ 0.8
Mutual funds	10.3	11.3	—	—	$ 11.3
Total	$ 11.1	$ 12.1	$ —	$ —	$ 12.1

(a) Reported in other investments on the balance sheet.

Derivative Fair Value Measurements
NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

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

As of Dec. 31, 2018, accumulated other comprehensive losses related to interest rate derivatives included $0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

Wholesale and Commodity Trading Risk — NSP-Minnesota conducts various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy, energy-related instruments and natural gas-related instruments, including derivatives. NSP-Minnesota is allowed to conduct these activities within guidelines and limitations as approved by its risk management committee, comprised of management personnel not directly involved in activities governed by this policy.

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

As of Dec. 31, 2018, NSP-Minnesota had no vehicle fuel contracts designated as cash flow hedges. NSP-Minnesota may enter into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, but may not be designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Immaterial amounts to income related to the ineffectiveness of cash flow hedges were recorded for the years ended Dec. 31, 2018 and 2017.

As of Dec. 31, 2018, there were no net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses or related amounts expected to be reclassified into earnings during the next 12 months.

NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

Gross notional amounts of commodity forwards, options and FTRs at Dec. 31:

(Amounts in Millions) (a) (b)	2018	2017
Megawatt hours of electricity	56.8	41.7
Million British thermal units of natural gas	42.7	23.8
Gallons of vehicle fuel	—	0.2

(a) Amounts are not reflective of net positions in the underlying commodities.

(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Consideration of Credit Risk and Concentrations — NSP-Minnesota continuously monitors the creditworthiness of counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Impact of credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the balance sheets.

NSP-Minnesota employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. NSP-Minnesota's most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to its wholesale, trading and non-trading commodity activities. As of Dec. 31, 2018, six of NSP-Minnesota's 10 most significant counterparties for these activities, comprising $35.9 million or 44% of this credit exposure, had investment grade credit ratings from Standard & Poor's Rating Services, Moody's Investor Services or Fitch Ratings.

Two of the 10 most significant counterparties, comprising $14.4 million or 18% of this credit exposure, were not rated by these external agencies, but based on NSP-Minnesota's internal analysis, had credit quality consistent with investment grade. One of the 10 most significant counterparties, comprising $1.3 million or 2% of this credit exposure, had credit quality less than investment grade, based on ratings from external analysis. One of the 10 most significant counterparties, comprising $11.8 million or 14% of this credit exposure, had credit quality less than investment grade based on rating from internal analysis. Seven of these significant counterparties are municipal or cooperative electric entities, or other utilities.

Qualifying Cash Flow Hedges — Financial impact of qualifying interest rate and vehicle fuel cash flow hedges on NSP-Minnesota's accumulated other comprehensive loss, included in the statements of common stockholder's equity and in the statements of comprehensive income:

(Millions of Dollars)	2018	2017
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (20.9)	$ (18.2)
After-tax net unrealized gains related to derivatives accounted for as hedges	—	0.1
After-tax net realized losses on derivative transactions reclassified into earnings	0.7	0.9
Adoption of ASU. 2018-02 (a)	—	(3.7)
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (20.2)	$ (20.9)

(a) In 2017, NSP-Minnesota implemented ASU No. 2018-02 related to TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

Impact of derivative activity:

	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
(Millions of Dollars)	**Accumulated Other Comprehensive Loss**	**Regulatory (Assets) and Liabilities**
Year Ended Dec. 31, 2018		
Other derivative instruments		
Electric commodity	$ —	$ (5.5)
Natural gas commodity	—	1.8
Total	$ —	$ (3.7)
Year Ended Dec. 31, 2017		
Derivatives designated as cash flow hedges		
Vehicle fuel and other commodity	$ 0.1	$ —
Total	$ 0.1	$ —
Other derivative instruments		
Electric commodity	$ —	$ 9.3
Natural gas commodity	—	(1.9)
Total	$ —	$ 7.4

	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Millions of Dollars)	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2018			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.1 (a)	$ —	$ —
Vehicle fuel and other commodity	(0.1) (b)	—	—
Total	$ 1.0	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 10.9 (c)
Electric commodity	—	3.3 (d)	—
Natural gas commodity	—	(1.9) (e)	(1.3) (e)
Total	$ —	$ 1.4	$ 9.6
Year Ended Dec. 31, 2017			
Derivatives designated as cash flow hedges			
Interest rate	$ 1.5 (a)	$ —	$ —
Total	$ 1.5	$ —	$ —
Other derivative instruments			
Commodity trading	$ —	$ —	$ 9.4 (c)
Electric commodity	—	(13.8) (d)	—
Natural gas commodity	—	1.0 (e)	(1.2) (e)
Total	$ —	$ (12.8)	$ 8.2

(a) Amounts are recorded to interest charges.
(b) Amounts are recorded to operating expenses.
(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.
(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.
(e) Amounts are recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets and liabilities, as appropriate.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2018 and 2017.

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheets, may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota's credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies, or for cross-default contractual provisions if there was a failure under other financing arrangements related to payment terms or other covenants. As of Dec. 31, 2018 and 2017, there were no derivative instruments in a liability position with such underlying contract provisions.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2018 and 2017.

Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, NSP-Minnesota's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2018 and 2017:

	Dec. 31, 2018						Dec. 31, 2017					
	Fair Value						Fair Value					
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**
Current derivative assets												
Derivatives designated as cash flow hedges:												
Vehicle fuel and other commodity	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 0.1	$ —	$ 0.1	$ —	$ 0.1
Other derivative instruments:												
Commodity trading	1.1	27.1	2.2	30.4	(16.0)	14.4	1.7	17.1	0.1	18.9	(11.7)	7.2
Electric commodity	—	—	10.5	10.5	(0.1)	10.4	—	—	17.6	17.6	(0.4)	17.2
Natural gas commodity	—	1.0	—	1.0	—	1.0	—	0.1	—	0.1	—	0.1
Total current derivative assets	$ 1.1	$ 28.1	$ 12.7	$ 41.9	$ (16.1)	25.8	$ 1.7	$ 17.3	$ 17.7	$ 36.7	$ (12.1)	24.6
PPAs (b)						—						0.6
Current derivative instruments						$ 25.8						$ 25.2
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	$ —	$ 25.3	$ 5.0	$ 30.3	$ (13.4)	$ 16.9	$ —	$ 29.1	$ 5.4	$ 34.5	$ (6.5)	$ 28.0
Total noncurrent derivative assets	$ —	$ 25.3	$ 5.0	$ 30.3	$ (13.4)	16.9	$ —	$ 29.1	$ 5.4	$ 34.5	$ (6.5)	28.0
PPAs (b)						0.1						0.1
Noncurrent derivative instruments						$ 17.0						$ 28.1

	December 31, 2018						December 31, 2017					
	Fair Value						Fair Value					
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Fair Value Total**	**Netting (a)**	**Total**
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 1.4	$ 23.9	$ 1.7	$ 27.0	$ (24.5)	$ 2.5	$ 1.7	$ 13.9	$ —	$ 15.6	$ (12.0)	$ 3.6
Electric commodity	—	—	0.1	0.1	(0.1)	—	—	—	0.4	0.4	(0.4)	—
Total current derivative liabilities	$ 1.4	$ 23.9	$ 1.8	$ 27.1	$ (24.6)	2.5	$ 1.7	$ 13.9	$ 0.4	$ 16.0	$ (12.4)	3.6
PPAs (b)						14.0						14.1
Current derivative instruments						$ 16.5						$ 17.7
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	$ 0.1	$ 16.0	$ 1.6	$ 17.7	$ 17.9	$ 35.6	$ —	$ 22.2	$ —	$ 22.2	$ (9.4)	$ 12.8
Total noncurrent derivative liabilities	$ 0.1	$ 16.0	$ 1.6	$ 17.7	$ 17.9	35.6	$ —	$ 22.2	$ —	$ 22.2	$ (9.4)	12.8
PPAs (b)						76.6						89.9
Noncurrent derivative instruments						$ 112.2						$ 102.7

(a) NSP-Minnesota nets derivative instruments and related collateral in its balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2018 and 2017. At Dec. 31, 2018 and 2017, derivative assets and liabilities include $31.5 million and $0 million of obligations to return cash collateral, respectively. At Dec. 31, 2018 and 2017, derivative assets and liabilities include the rights to reclaim cash collateral of $8.7 million and $3.1 million, respectively. The counterparty netting excludes settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

(b) During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives for the years ended Dec. 31, 2018 and 2017:

(Millions of Dollars)	Year Ended Dec. 31 2018	Year Ended Dec. 31 2017
Balance at Jan. 1	$ 22.6	$ 15.3
Purchases	26.4	40.6
Settlements	(17.2)	(41.7)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings [(a)]	(1.5)	5.5
Net (losses) gains recognized as regulatory assets and liabilities	(16.0)	2.9
Balance at Dec. 31	$ 14.3	$ 22.6

(a) Amounts relate to commodity derivatives held at the end of the period.

NSP-Minnesota recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for derivative instruments for the years ended 2017 and 2018.

Fair Value of Long-Term Debt

As of Dec. 31, other financial instruments for which the carrying amount did not equal fair value:

(Millions of Dollars)	2018 Carrying Amount	2018 Fair Value	2017 Carrying Amount	2017 Fair Value
Long-term debt, including current portion	$ 4,979.4	$ 5,230.9	$ 4,978.3	$ 5,601.9

Fair value of NSP-Minnesota's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. Fair value estimates are based on information available to management as of Dec. 31, 2018 and 2017, and given the observability of the inputs, fair values presented for long-term debt were assigned as Level 2.

8. Benefit Plans and Other Postretirement Benefits

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

In addition to the qualified pension plans, Xcel Energy maintains a supplemental executive retirement plan (SERP) and a nonqualified pension plan. The SERP is maintained for certain executives that were participants in the plan in 2008, when the SERP was closed to new participants. The nonqualified pension plan provides benefits for compensation that is in excess of the limits applicable to the qualified pension plans, with distributions funded by Xcel Energy's operating cash flows. Obligations of the SERP and nonqualified plan as of Dec. 31, 2018 and 2017 were $33 million and $37 million, respectively, of which $4 million and $5 million were attributable to NSP-Minnesota. In 2018 and 2017, Xcel Energy recognized net benefit cost for the SERP and nonqualified plans of $4 million and $5 million, respectively, of which $1 million was attributable to NSP-Minnesota in both years.

In 2016, Xcel Energy established rabbi trusts to provide partial funding for future distributions of the SERP and its deferred compensation plan. Rabbi trust funding of deferred compensation plan distributions attributable to NSP-Minnesota will be supplemented by NSP-Minnesota's operating cash flows.

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- NSP-Minnesota discontinued subsidizing health care benefits for non-bargaining employees retiring after 1998 and for bargaining employees who retired after 1999.

Xcel Energy and NSP-Minnesota base the investment-return assumption on expected long-term performance for each of the asset classes in its pension and postretirement health care portfolios.

For pension assets, Xcel Energy and NSP-Minnesota consider the historical returns achieved by their asset portfolio over the past 20 years or longer period, as well as the long-term projected return levels. Xcel Energy and NSP-Minnesota continually review their pension assumptions.

Pension cost determination assumes a forecasted mix of investment types over the long-term.

- Investment returns in 2018 were below the assumed level of 7.10%;
- Investment returns in 2017 were above the assumed level of 7.10%; and
- In 2019, NSP-Minnesota's expected investment-return assumption is 7.10%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy's and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the asset allocation given the long-term risk, return, correlation and liquidity characteristics of each particular asset class.

There were no significant concentrations of risk in any industry, index, or entity. Market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by the assets in any year.

State agencies also have issued guidelines to the funding of postretirement benefit costs.

Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Plan Assets

The following presents, for each of the fair value hierarchy levels, NSP-Minnesota's pension plan assets measured at fair value:

	Dec. 31, 2018 (a)					Dec. 31, 2017 (a)				
(Millions of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Measured at NAV**	**Total**
Cash equivalents	$ 31.8	$ —	$ —	$ —	$ 31.8	$ 53.4	$ —	$ —	$ —	$ 53.4
Commingled funds:	241.0	—	—	271.2	512.2	285.2	—	—	302.4	587.6
Debt securities:	—	143.7	—	—	143.7	—	159.0	—	—	159.0
Equity securities:	29.3	—	—	—	29.3	32.1	—	—	—	32.1
Other	0.5	1.3	—	(8.2)	(6.4)	(8.7)	1.0	—	0.1	$ (7.6)
Total	$ 302.6	$ 145.0	$ —	$ 263.0	$ 710.6	$ 362.0	$ 160.0	$ —	$ 302.5	$ 824.5

(a) See Note 7 for further information on fair value measurement inputs and methods.

The following presents, for each of the fair value hierarchy levels, NSP-Minnesota's postretirement benefit plan assets that were measured at fair value:

	Dec. 31, 2018 (a)					Dec. 31, 2017 (a)				
(Millions of Dollars)	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	$ 0.1	$ —	$ —	$ —	$ 0.1	$ 0.4	$ —	$ —	$ —	$ 0.4
Insurance contracts	—	0.3	—	—	0.3	—	0.7	—	—	0.7
Commingled funds	0.8	—	—	0.2	1.0	2.1	—	—	—	2.1
Debt securities	—	1.0	—	—	1.0	—	2.8	—	—	2.8
Equity securities	—	—	—	—	—	0.5	—	—	—	0.5
Total	$ 0.9	$ 1.3	$ —	$ 0.2	$ 2.4	$ 3.0	$ 3.5	$ —	$ —	$ 6.5

(a) See Note 7 for further information on fair value measurement inputs and methods.

No assets transferred in or out of Level 3 for 2018 or 2017.

Funded Status — Comparisons of the actuarially computed benefit obligation, changes in plan assets and funded status of the pension and postretirement health care plans for NSP-Minnesota are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	2018	2017	2018	2017
Change in Benefit Obligation:				
Obligation at Jan. 1	$ 1,035.1	$ 1,036.5	$ 88.8	$ 86.7
Service cost	28.0	27.8	0.2	0.1
Interest cost	35.2	40.7	3.1	3.4
Plan amendments	—	(4.4)	—	—
Actuarial (gain) loss	(50.8)	64.1	(9.0)	5.9
Plan participants' contributions	—	—	0.4	0.4
Benefit payments (a)	(140.5)	(129.6)	(7.5)	(7.7)
Obligation at Dec. 31	$ 907.0	$ 1,035.1	$ 76.0	$ 88.8
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	$ 824.5	$ 783.2	$ 6.5	$ 3.7
Actual return on plan assets	(36.5)	110.1	—	—
Employer contributions	63.1	60.7	3.0	10.1
Plan participants' contributions	—	—	0.4	0.4
Benefit payments	(140.5)	(129.5)	(7.5)	(7.7)
Fair value of plan assets at Dec. 31	$ 710.6	$ 824.5	$ 2.4	$ 6.5
Funded status of plans at Dec. 31	$ (196.4)	$ (210.6)	$ (73.6)	$ (82.3)
Amounts recognized in the Balance Sheet at Dec. 31:				
Noncurrent liabilities	$ (196.4)	$ (210.6)	$ (73.6)	$ (82.3)

(a) Includes approximately $105 million of lump-sum benefit payments used in the determination of a settlement charge.

Significant Assumptions Used to Measure Benefit Obligations:				
Discount rate for year-end valuation	4.31%	3.63%	4.32%	3.62%
Expected average long-term increase in compensation level	3.75%	3.75%	N/A	N/A
Mortality table	RP-2014	RP-2014	RP-2014	RP-2014
Health care costs trend rate — initial: Pre-65	N/A	N/A	6.50%	7.00%
Health care costs trend rate — initial: Post-65	N/A	N/A	5.30%	5.50%
Ultimate trend assumption — initial: Pre-65	N/A	N/A	4.50%	4.50%
Ultimate trend assumption — initial: Post-65	N/A	N/A	4.50%	4.50%
Years until ultimate trend is reached	N/A	N/A	4	5

The accumulated benefit obligation for the pension plan was $845 million and $969 million as of Dec. 31, 2018 and 2017, respectively.

Net Periodic Benefit Cost (Credit) — Net periodic benefit cost (credit) other than the service cost component is included in other income in the statement of income.

Components of net periodic benefit cost (credit) and the amounts recognized in other comprehensive income and regulatory assets and liabilities are as follows:

	Pension Benefits		Postretirement Benefits	
(Millions of Dollars)	**2018**	**2017**	**2018**	**2017**
Service cost	$ 28.0	$ 27.8	$ 0.2	$ 0.1
Interest cost	35.2	40.7	3.1	3.4
Expected return on plan assets	(58.2)	(60.1)	(0.4)	(0.2)
Amortization of prior service cost	(0.1)	1.1	(3.0)	(3.0)
Amortization of net loss	38.5	39.6	2.4	2.0
Settlement charge [(a)]	48.8	48.2	—	—
Net periodic pension cost	92.2	97.3	2.3	2.3
Costs not recognized due to effects of regulation	(66.0)	(72.2)	—	—
Net benefit cost recognized for financial reporting	$ 26.2	$ 25.1	$ 2.3	$ 2.3
Significant Assumptions Used to Measure Costs:				
Discount rate	3.63%	4.13%	3.62%	4.13%
Expected average long-term increase in compensation level	3.75	3.75	—	—
Expected average long-term rate of return on assets	7.10	7.10	5.30	5.80

(a) A settlement charge is required when the amount of lump-sum distributions during the year is greater than the sum of the service and interest cost components of the annual net periodic pension cost. In 2018 and 2017, as a result of lump-sum distributions during the 2018 and 2017 plan years, NSP-Minnesota recorded a total pension settlement charge of $48.8 million in 2018 and $48.2 million in 2017, which was not recognized due to the effects of regulation.

(Millions of Dollars)	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	$ 502.0	$ 545.3	$ 34.3	$ 45.3
Prior service (credit) cost	(1.2)	(1.3)	(12.4)	(15.4)
Total	$ 500.8	$ 544.0	$ 21.9	$ 29.9
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Noncurrent deferred debits	$ 500.8	$ 544.0	$ 20.5	$ 28.0
Deferred income taxes	—	—	0.4	0.5
Net-of-tax accumulated other comprehensive income	—	—	1.0	1.4
Total	$ 500.8	$ 544.0	$ 21.9	$ 29.9
Measurement date	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. Required contributions were made in 2017 - 2019 to meet minimum funding requirements. Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- $150 million in January 2019, of which $47 million is attributable to NSP-Minnesota;
- $150 million in 2018, of which $63 million was attributable to NSP-Minnesota; and,
- $162 million in 2017, of which $61 million was attributable to NSP-Minnesota.

The postretirement health care plans have no funding requirements other than fulfilling benefit payment obligations, when claims are presented and approved. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities. Voluntary postretirement funding contributions:

- $11 million in January 2019, of which $7 million is attributable to NSP-Minnesota;
- $11 million in 2018, of which $3 million, was attributable to NSP-Minnesota; and,
- $20 million in 2017, of which $10 million was attributable to NSP-Minnesota.

Target asset allocations:

	Pension Benefits 2018	Pension Benefits 2017	Postretirement Benefits 2018	Postretirement Benefits 2017
Domestic and international equity securities	37 %	38 %	18 %	24 %
Long-duration fixed income and interest rate swap securities	28	23	—	—
Short-to-intermediate fixed income securities	18	21	70	60
Alternative investments	15	16	8	9
Cash	2	2	4	7
Total	100 %	100 %	100 %	100 %

Plan Amendments — Xcel Energy, which includes NSP-Minnesota, amended the Xcel Energy Pension Plan in 2017 to reduce supplemental benefits for non-bargaining participants as well as to allow the transfer of a portion of non-qualified pension obligations into the qualified plans.

In 2018 and 2017, there were no plan amendments made which affected the benefit obligation.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2019	$ 93.4	$ 7.2	$ —	$ 7.2
2020	81.2	7.0	—	7.0
2021	80.1	6.7	—	6.7
2022	79.0	6.3	—	6.3
2023	77.2	6.0	—	6.0
2024-2027	342.3	26.0	—	26.0

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover most employees. The expense to these plans for NSP-Minnesota was approximately $12 million in 2018 and 2017.

Multiemployer Plans

NSP-Minnesota contributes to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees who may perform services for multiple employers and do not participate in the NSP-Minnesota sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

9. Commitments and Contingencies

Legal

NSP-Minnesota is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves complex judgments about future events. Management maintains accruals for losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on NSP-Minnesota's financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Rate Matters

Sherco — In NSP-Minnesota's 2013 fuel reconciliation filing, the MPUC made recovery of replacement power costs associated with the 2011 incident at its Sherco Unit 3 plant provisional and subject to further review following conclusion of litigation commenced by NSP-Minnesota, Southern Minnesota Municipal Power Agency (SMMPA) (Co-owner of Sherco Unit 3) and insurance companies against General Electric (GE).

In 2018, NSP-Minnesota and SMMPA reached a settlement with GE. NSP-Minnesota has notified the MPUC of its proposal to refund the GE settlement proceeds back to customers through the fuel clause adjustment. The insurance providers continued their litigation against GE and the case went to trial. In 2018, GE prevailed in the lawsuit with the insurance companies, however, the jury found comparable fault, finding that GE was 52% and NSP-Minnesota was 48% at fault. At that point in the litigation, NSP-Minnesota was no longer involved in the case and was not present to make arguments about its role in the event. The specific issue leading to the fault apportionment was also not before the jury and not relevant to the outcome of the trial.

In January 2019, the Minnesota Department of Commerce (DOC) recommended that NSP-Minnesota refund $20 million of previously recovered purchased power costs to its customers, based on the jury's apportionment of fault. The Minnesota Office of the Attorney General (OAG) recommended the MPUC withhold any decision until the underlying litigation by the insurance providers (currently under appeal) is concluded. The DOC subsequently filed comments agreeing with the OAG's recommendation to withhold a decision pending the outcome of any appeals. NSP-Minnesota filed reply comments arguing that the DOC recommendations are without merit and that it acted prudently in operating the plant and its settlement with GE was reasonable.

MISO Return on Equity (ROE) Complaints — In November 2013 and February 2015, customers filed complaints against MISO TOs including NSP-Minnesota and NSP-Wisconsin. The first complaint argued for a reduction in the base ROE in MISO transmission formula rates from 12.38% to 9.15%, and removal of ROE adders (including those for RTO membership). The second complaint sought to reduce base ROE from 12.38% to 8.67%. In September 2016, the FERC issued an order granting a 10.32% base ROE (10.82% with the RTO adder) effective for the first complaint period of Nov. 12, 2013 to Feb. 11, 2015 and subsequent to the date of the order. The United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) subsequently vacated and remanded FERC Opinion No. 531, which had established the ROE methodology on which the September 2016 FERC order was based.

In October 2018, the FERC issued a New England Transmission Owners base ROE order that addressed the D.C. Circuit's actions on Opinion No. 531. Under a new proposed two step ROE approach, the FERC has indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the Discounted Cash Flows, Capital Asset Pricing Model, and Expected Earnings models. The FERC proposes that if necessary, it would then set a new ROE by averaging the results of these models plus a Risk Premium model.

With respect to the MISO TOs, the FERC subsequently made preliminary determinations in a November 2018 order that the MISO base ROE in effect for the first complaint period (12.38%) was outside the range of reasonableness, and should be reduced. The FERC indicated its preliminary analysis using the new ROE approach resulted in a base ROE of 10.28% for the first compliant period, compared to the previously ordered base ROE of 10.32%. A procedural schedule has been set for the first half of 2019, with the FERC expected to act no earlier than the second half of 2019. NSP-Minnesota has recognized a current refund liability consistent with its best estimate of the final ROE.

Environmental

New and changing federal and state environmental mandates can create financial liabilities for NSP-Minnesota, which are normally recovered through the regulated rate process.

Site Remediation — Various federal and state environmental laws impose liability where hazardous substances or other regulated materials have been released to the environment. NSP-Minnesota may sometimes pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota's predecessors or other parties have caused environmental contamination.

Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs); and third-party sites, such as landfills, for which NSP-Minnesota is alleged to have sent wastes to that site.

MGP, Landfill or Disposal Sites — NSP-Minnesota is currently investigating or remediating six MGP, landfill or other disposal sites sites across its service territories, and these activities will continue through at least 2019. NSP-Minnesota accrued $6 million as of Dec. 31, 2018, and $19 million as of Dec. 31, 2017 for these sites. There may be insurance recovery and/or recovery from other potentially responsible parties, offsetting some portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of solid waste. In 2015, the United States Environmental Protection Agency (EPA) published the Coal Combustion Residuals (CCR) Rule. Litigation was brought challenging the rule in the D.C. Circuit. Under the CCR Rule, utilities are required to complete groundwater sampling around their CCR landfills and surface impoundments. By the end of 2019, only three of NSP-Minnesota's regulated ash units are expected to be in operation. NSP-Minnesota is conducting additional groundwater sampling and will evaluate whether corrective action is required at any CCR landfills or surface impoundments.

Until NSP-Minnesota completes its assessment, it is uncertain what impact, if any, there will be on the operations, financial condition or cash flows. In August 2018, the D.C. Circuit ruled that the EPA cannot allow utilities to continue to use unlined impoundments (including clay lined impoundments) for the storage or disposal of coal ash. Litigation is ongoing regarding the deadline for closing or retrofitting these impoundments. The decision will require NSP-Minnesota to expedite closure plans for one impoundment in Minnesota (see ARO removal costs below) and will require the construction of a new impoundment, which is estimated to cost $6 million.

Federal Clean Water Act (CWA) WOTUS Rule — In 2015, the EPA and the U.S. Army Corps of Engineers published a final rule that significantly broadened the scope of waters under the CWA that are subject to federal jurisdiction, referred to as "WOTUS". The Rule has been subject to significant litigation and is currently stayed in a portion of the country. NSP-Minnesota cannot estimate potential impacts until the legal and administrative processes are finalized, but expects costs will be recoverable through regulatory mechanisms.

Federal CWA Effluent Limitations Guidelines (ELG) — In 2015, the EPA issued a final ELG rule for power plants that discharge treated effluent to surface waters as well as utility-owned landfills that receive CCRs. In 2017, the EPA delayed the compliance date for flue gas desulfurization wastewater and bottom ash transport until November 2020. After 2020, NSP-Minnesota estimates that ELG compliance will cost approximately $10 million to complete. The EPA, however, is conducting a rulemaking process to potentially revise the effluent limitations and pretreatment standards, which may impact compliance costs. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

Federal CWA Section 316(b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing impingement and entrainment of aquatic species. NSP-Minnesota estimates the likely cost for complying with impingement and entrainment requirements is approximately $39 million, to be incurred between 2019 and 2028. NSP-Minnesota believes six plants could be required by state regulators to make improvements to reduce impingement and entrainment. The exact total cost of the impingement and entrainment improvements is uncertain, but could be up to $194 million. NSP-Minnesota anticipates these costs will be fully recoverable through regulatory mechanisms.

AROs — AROs have been recorded for NSP-Minnesota's assets. For nuclear assets, the ARO is associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and Prairie Island (PI).

Aggregate fair value of NSP-Minnesota's legally restricted assets, for funding future nuclear decommissioning, was 2.1 billion for 2018 and 2017.

NSP-Minnesota's AROs were as follows:

	Dec. 31, 2018				
(Millions of Dollars)	Jan. 1, 2018	Amounts Settled [(a)]	Accretion	Cash Flow Revisions [(b)]	Dec. 31, 2018 [(c)]
Electric					
Nuclear	$ 1,873.6	$ —	$ 94.7	$ —	$ 1,968.3
Wind	94.1	—	4.3	6.5	104.9
Steam and other production	65.7	(6.6)	2.1	(10.4)	50.8
Distribution	5.8	—	0.2	8.5	14.5
Transmission	0.2	—	—	—	0.2
Natural gas					
Transmission and distribution	43.6	—	1.8	(7.2)	38.2
Gas storage	0.2	—	—	—	0.2
Common					
Common	0.7	—	0.1	—	0.8
Total liability	$ 2,083.9	$ (6.6)	$ 103.2	$ (2.6)	$ 2,177.9

(a) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.
(b) In 2018, AROs were revised for changes in timing and estimates of cash flows. Changes in gas transmission and distribution AROs were mainly related to increased gas line mileage and number of services, which were more than offset by increased discount rates. Changes in electric distribution AROs primarily related to increased labor costs.
(c) There were no ARO amounts incurred in 2018.

	Dec. 31, 2017				
(Millions of Dollars)	Jan. 1, 2017	Amounts Settled [(a)]	Accretion	Cash Flow Revisions [(b)]	Dec. 31, 2017 [(c)]
Electric					
Nuclear	$ 2,249.3	$ —	$ 113.8	$ (489.5)	$ 1,873.6
Wind	90.1	—	4.0	—	94.1
Steam and other production	70.1	(4.9)	2.5	(2.0)	65.7
Distribution	5.6	—	0.2	—	5.8
Transmission	0.2	—	—	—	0.2
Natural gas					
Transmission and distribution	35.8	—	1.5	6.3	43.6
Gas storage	0.2	—	—	—	0.2
Common					
Common	1.3	(0.6)	—	—	0.7
Total liability	$ 2,452.6	$ (5.5)	$ 122.0	$ (485.2)	$ 2,083.9

(a) Amounts settled related to asbestos abatement projects and closure of certain ash containment facilities.
(b) In 2017, AROs were revised for changes in timing and estimates of cash flows. Nuclear AROs decreased due to updated assumptions in the nuclear triennial filing.
(c) There were no ARO amounts incurred in 2017.

Indeterminate AROs — Outside of the recorded asbestos AROs, other plants or buildings may contain asbestos due to the age of many of NSP-Minnesota's facilities, but no confirmation or measurement of the cost of removal could be determined as of Dec. 31, 2018. Therefore, an ARO has not been recorded for these facilities.

Nuclear Related

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to $14.1 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $450.0 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $13.6 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear incident. NSP-Minnesota is subject to assessments of up to $137.6 million per reactor-incident for each of its three licensed reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $20.5 million per reactor-incident during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective November 2018.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL) and European Mutual Association for Nuclear Insurance (EMANI). The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power during prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL and EMANI to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. NSP-Minnesota could be subject to annual maximum assessments of approximately $18.0 million for business interruption insurance and $39.0 million for property damage insurance if losses exceed accumulated reserve funds.

Nuclear Fuel Disposal — NSP-Minnesota is responsible for temporarily storing spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from U.S. nuclear plants, but no such facility is yet available.

NSP-Minnesota owns temporary on-site storage facilities for spent fuel at its Monticello and PI nuclear plants, which consist of storage pools and dry cask facilities. The Monticello dry-cask storage facility currently stores all 30 of the authorized canisters. The PI dry-cask storage facility currently stores 44 of the 64 authorized casks. Monticello's future spent fuel will continue to be placed in its spent fuel pool. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's operating license and be completed by 2091. NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2030 and its PI nuclear plant until 2033 for Unit 1 and 2034 for Unit 2.

Future decommissioning costs of nuclear facilities are estimated through triennial periodic studies that assess the costs and timing of planned nuclear decommissioning activities for each unit.

The obligation for decommissioning is expected to be funded 100% by the external decommissioning trust fund. This cost study assumes the external decommissioning fund will earn an after-tax return between 5.23% and 6.30%. Realized and unrealized gains on fund investments are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Decommissioning costs are quantified in 2014 dollars. Escalation rates are 4.36% for plant removal activities and 3.36% for fuel management and site restoration activities.

NSP-Minnesota has accumulated $2.1 billion of assets held in external decommissioning trusts in 2018. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation. Xcel Energy believes future decommissioning costs will continue to be recovered in customer rates. The following amounts were prepared on a regulatory basis and not directly recorded in the financial statements (ARO).

	Regulatory Basis	
(Millions of Dollars)	**2018**	**2017**
Estimated decommissioning cost obligation from most recently approved study (in 2014 dollars)	$ 3,012.3	$ 3,012.3
Effect of escalating costs	538.9	395.7
Estimated decommissioning cost obligation (in current dollars)	3,551.2	3,408.0
Effect of escalating costs to payment date	7,654.3	7,797.5
Estimated future decommissioning costs (undiscounted)	11,205.5	11,205.5
Effect of discounting obligation (using average risk-free interest rate of 3.33% and 2.80% for 2018 and 2017, respectively)	(6,911.5)	(6,398.1)
Discounted decommissioning cost obligation	$ 4,294.0	$ 4,807.4
Assets held in external decommissioning trust	$ 2,054.7	$ 2,143.3
Underfunding of external decommissioning fund compared to the discounted decommissioning obligation	2,239.3	2,664.1

Calculations and data used by the regulator in approving NSP-Minnesota's rates are useful in assessing future cash flows. Regulatory basis information is a means to reconcile amounts previously provided to the MPUC and utilized for regulatory purposes to amounts used for financial reporting.

Reconciliation of the discounted decommissioning cost obligation - regulated basis to the ARO recorded in accordance with GAAP:

(Millions of Dollars)	**2018**	**2017**
Discounted decommissioning cost obligation - regulated basis	$ 4,294.0	$ 4,807.4
Differences in discount rate and market risk premium	(1,446.4)	(1,402.8)
Operating expenses not included for GAAP	(879.3)	(1,041.5)
ARO differences between 2017 and 2014 cost studies	—	(489.5)
Nuclear production decommissioning ARO - GAAP	$ 1,968.3	$ 1,873.6

Decommissioning expenses recognized as a result of regulation:

(Millions of Dollars)	**2018**	**2017**
Annual decommissioning recorded as depreciation expense: (a) (b)	$ 20.4	$ 20.4

(a) Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

(b) Decommissioning expenses in 2018 and 2017 include Minnesota's retail jurisdiction annual funding requirement of approximately $14.0 million.

The 2014 nuclear decommissioning filing approved in 2015 has been used for the regulatory presentation for 2018 and 2017. The most recent triennial filing was submitted in December 2017 and was approved by the MPUC. It became effective on Jan. 1, 2019 and continued the accrual previously approved in the MPUC order, dated October 2015 from the 2014 filing. The 2020 accrual will be set subsequent to a compliance filing that is expected to be submitted in July 2019.

Leases — NSP-Minnesota leases a variety of equipment and facilities. These leases, primarily for office space, railcars, generating facilities, natural gas pipeline transportation, vehicles, aircraft and power-operated equipment, are accounted for as operating leases.

Total expenses (including capacity payments) under operating lease obligations for NSP-Minnesota and the corresponding capacity payments for PPAs accounted for as operating leases for the year ended Dec. 31:

(Millions of Dollars)	2018	2017
Total expense	$ 76.2	$ 76.9
Capacity payments	62.5	62.7

Included in the future commitments under operating leases are estimated future capacity payments under PPAs that have been accounted for as operating leases.

Future commitments under operating leases:

(Millions of Dollars)	Operating Leases	PPA [a] [b] Operating Leases	Total Operating Leases
2019	$ 13.5	$ 65.0	$ 78.5
2020	8.4	66.1	74.5
2021	8.4	67.1	75.5
2022	8.1	68.2	76.3
2023	7.3	69.3	76.6
Thereafter	36.0	143.5	179.5

(a) Amounts do not include PPAs accounted for as executory contracts.

(b) PPA operating leases contractually expire through 2026.

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers with expiration dates through 2039 for purchased power to meet system load and energy requirements, meet operating reserve obligations and as part of wholesale and commodity trading activities. In general, these agreements provide for energy payments, based on actual energy delivered and capacity payments. Certain PPAs accounted for as executory contracts also contain minimum energy purchase commitments.

Capacity and energy payments are contingent on the independent power producing entities (IPPs) meeting contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices. The effects of price adjustments on our financial results are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of $52.7 million and $84.1 million in 2018 and 2017, respectively.

At Dec. 31, 2018, the estimated future payments for capacity and energy that NSP-Minnesota is obligated to purchase pursuant to these executory contracts, subject to availability, were as follows:

(Millions of Dollars)	Capacity	Energy [a]
2019	$ 54.0	$ 98.7
2020	54.6	109.4
2021	62.2	157.4
2022	61.3	172.9
2023	62.7	176.9
Thereafter	109.5	328.1
Total [b]	$ 404.3	$ 1,043.4

(a) Excludes contingent energy payments for renewable energy PPAs.
(b) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Fuel Contracts — NSP-Minnesota has entered into various long-term commitments for the purchase and delivery of a significant portion of its coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2019 and 2037. NSP-Minnesota is required to pay additional amounts depending on actual quantities shipped under these agreements.

Estimated minimum purchases for these contracts as of Dec. 31, 2018:

(Millions of Dollars)	Coal	Nuclear fuel	Natural gas supply	Natural gas storage and transportation
2019	$ 194.7	$ 127.1	$ 43.6	$ 107.4
2020	87.4	50.9	1.4	97.5
2021	52.0	99.0	1.4	95.6
2022	34.7	78.5	0.8	92.6
2023	35.1	99.4	—	82.8
Thereafter	3.5	337.1	—	320.7
Total (a)	$ 407.4	$ 792.0	$ 47.2	$ 796.6

(a) Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Other

Guarantees — Under NSP-Minnesota's railcar lease agreement, accounted for as an operating lease, NSP-Minnesota guarantees the lessor proceeds from sale of the leased assets at the end of the lease term will at least equal the guaranteed residual value. The guarantee issued by NSP-Minnesota limits its exposure to a maximum amount stated in the guarantee; however, NSP-Minnesota expects sale proceeds to exceed the guaranteed amount.

The following table presents the guarantee issued and outstanding for NSP-Minnesota:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of residual value of assets under the Bank of Tokyo-Mitsubishi Capital Corporation Equipment Leasing Agreement	NSP-Minnesota	$ 4.8	$ —	(a)

(a) Actual fair value of leased assets is less than the guaranteed residual value amount at the end of the lease term in 2019.

10. Other Comprehensive Income

Changes in accumulated other comprehensive loss, net of tax, for the years ended Dec. 31, 2018 and 2017:

	2018									
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges			Unrealized Gains and Losses on Marketable Securities		Defined Benefit Pension and Postretirement Items			Total	
Accumulated other comprehensive (loss) income at Jan. 1	$	(20.9)		$	0.1	$	(3.7)		$	(24.5)
Other comprehensive (loss) income before reclassifications (net of taxes of $0, $0, and $0.3 respectively)		—			(0.1)		0.6			0.5
Losses reclassified from net accumulated other comprehensive loss:										
Interest rate derivatives (net of taxes of $0.3, $0, and $0, respectively) (a)		0.7	(a)		—		—			0.7
Amortization of net actuarial loss (net of taxes of $0, $0, and $0.1, respectively)		—			—		0.2	(b)		0.2
Net current period other comprehensive income (loss)		0.7			(0.1)		0.8			1.4
Accumulated other comprehensive loss at Dec. 31	$	(20.2)		$	—	$	(2.9)		$	(23.1)

	2017									
(Millions of Dollars)	Gains and Losses on Cash Flow Hedges			Unrealized Gains and Losses on Marketable Securities		Defined Benefit Pension and Postretirement Items			Total	
Accumulated other comprehensive (loss) income at Jan. 1	$	(18.2)		$	0.1	$	(2.7)		$	(20.8)
Other comprehensive (loss) income before reclassifications (net of taxes of $0, $0, and $0.1, respectively)		0.1			—		(0.5)			(0.4)
Losses reclassified from net accumulated other comprehensive loss:										
Interest rate derivatives (net of taxes of $0.6, $0, and $0, respectively)		0.9	(a)		—		—			0.9
Amortization of net actuarial loss (net of taxes of $0, $0, and $0.1, respectively)		—			—		0.1	(b)		0.1
Net current period other comprehensive income (loss)		1.0			—		(0.4)			0.6
Adoption of ASU No. 2018-02 (c)		(3.7)			—		(0.6)			(4.3)
Accumulated other comprehensive (loss) income at Dec. 31	$	(20.9)		$	0.1	$	(3.7)		$	(24.5)

(a) Included in interest charges.

(b) Included in the computation of net periodic pension and postretirement benefit costs. See Note 8 for further information.

In 2017, NSP-Minnesota implemented ASU No. 2018-02 related to the TCJA, which resulted in reclassification of certain credit balances within net accumulated other comprehensive loss to retained earnings.

11. Related Party Transactions

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

Xcel Energy Inc., NSP-Minnesota, PSCo and SPS have established a utility money pool arrangement. See Note 5 for further information.
The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.
Significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Millions of Dollars)	2018	2017
Operating revenues:		
Electric	$ 473.7	$ 490.2
Operating expenses:		
Purchased power	61.1	66.8
Transmission expense	96.8	110.5
Other operating expenses — paid to Xcel Energy Services Inc.	534.8	539.4
Interest expense	0.3	—

Accounts receivable and payable with affiliates at Dec. 31 were:

	2018		2017	
(Millions of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	$ 11.0	$ —	$ 17.8	$ —
PSCo	—	17.9	—	7.7
SPS	—	4.7	—	1.0
Other subsidiaries of Xcel Energy Inc.	1.2	88.1	30.7	73.6
	$ 12.2	$ 110.7	$ 48.5	$ 82.3

12. Supplementary Cash Flow Data

	Year Ended Dec. 31	
(Millions of Dollars)	2018	2017
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (209.1)	$ (219.9)
Cash received (paid) for income taxes, net	88.9	(71.0)
Supplemental disclosure of non-cash investing transactions:		
Accrued property, plant and equipment additions	$ 92.5	$ 93.1
Inventory transfers to property, plant and equipment	60.8	17.3
Allowances for funds used during construction	23.8	29.5

13. Energy Storage Assets (FERC Order No. 784)

The FERC issued Order No. 784, "Third-Party Provision of Ancillary Services; Accounting and Financial Reporting For New Electric Storage Technologies" in July 2013. In February 2014, FERC issued guidance on complying with Order No. 784's new accounting and disclosure requirements until their Form 1 and Form 3 statements are revised to accommodate the changes. That guidance included a requirement to include disclosure information related to energy storage technologies in the notes to the financial statements. This information is presented below.

The Luverne Wind2Battery project is a one megawatt (MW) sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind wind power generating facility near Luverne, Minn. It is being used to store, control and dispatch energy when needed for supply or transmission stability purposes. The purpose of the facility is to provide NSP-Minnesota with experience and information that will allow NSP-Minnesota to assess and improve upon the viability of scaling up battery storage on the system as more wind power is added to meet the renewable policies.

Energy Plant Account
Energy storage assets are recorded in Account 348 in the amount of $4,128,902 at Dec. 31, 2018 and 2017. Due to FERC software limitations, these amounts are reported in Account 342.

Power Purchased Account
Energy storage-related purchased power costs are recorded in Account 555.1 in accordance with FERC Order No. 784 in the credit amount of $120,352 and $23,977 for the year ended Dec. 31, 2018 and 2017, respectively, reflecting true-up activity during the period. Due to FERC software limitations, these amounts are reported in Account 555.

Operation and Maintenance Expense Accounts
Energy storage-related operating expenses are recorded in Account 548.1 in accordance with FERC Order No. 784 in the amount of zero for the year ended Dec. 31, 2018 and 2017, respectively. Due to FERC software limitations, these amounts are reported in Account 548.

Energy storage-related maintenance expenses are recorded in Account 553.1 in accordance with FERC Order No. 784 in the amount of zero for the year ended Dec. 31, 2018 and 2017, respectively. Due to FERC software limitations, these amounts are reported in Account 553.

The following table presents NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2018, as required by FERC Order No. 784:

Line no.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	$ 4,128,902	$ —	$ —	$ —	$ (120,352)	$ —

The following table presents NSP-Minnesota's Energy Storage Operations for small plants as of and for the year ended Dec. 31, 2017, as required by FERC Order No. 784:

Line no.	Name of Energy Storage Project	Functional Classification	Location of the Project	Project Cost	Operations (Excluding Fuel used in Storage Operations)	Maintenance	Cost of fuel used in storage operations	Account No. 555.1, Power Purchased for Storage Operations	Other Expenses
1	Luverne, Minn. Wind2Battery Project	Production	Luverne, Minn.	$ 4,128,902	$ —	$ —	$ —	$ (23,977)	$ —

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	849,906			(3,424,770)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	23,136			(524,084)
3	Preceding Quarter/Year to Date Changes in Fair Value	385			(565,692)
4	Total (lines 2 and 3)	23,521			(1,089,776)
5	Balance of Account 219 at End of Preceding Quarter/Year	873,427			(4,514,546)
6	Balance of Account 219 at Beginning of Current Year	873,427			(4,514,546)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				219,948
8	Current Quarter/Year to Date Changes in Fair Value	(130,552)			659,828
9	Total (lines 7 and 8)	(130,552)			879,776
10	Balance of Account 219 at End of Current Quarter/Year	742,875			(3,634,770)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(18,184,831)	(23,014)	(20,782,709)	[redacted]	[redacted]
2	(2,763,287)	(22,527)	(3,286,762)	[redacted]	[redacted]
3		98,292	(467,015)	[redacted]	[redacted]
4	(2,763,287)	75,765	(3,753,777)	490,121,306	486,367,529
5	(20,948,118)	52,751	(24,536,486)	[redacted]	[redacted]
6	(20,948,118)	52,751	(24,536,486)	[redacted]	[redacted]
7	762,466	(107,762)	874,652	[redacted]	[redacted]
8		31,993	561,269	[redacted]	[redacted]
9	762,466	(75,769)	1,435,921	492,335,131	493,771,052
10	(20,185,652)	(23,018)	(23,100,565)	[redacted]	[redacted]

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

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

Other cash flow hedging activity relates primarily to vehicle fuel and natural gas commodity derivatives.

This footnote applies to all of column g.

Schedule Page: 122(a)(b) Line No.: 2 Column: b

The amount reported relates to the reclassification of Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Schedule Page: 122(a)(b) Line No.: 2 Column: e

Includes a ($668,931) reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Schedule Page: 122(a)(b) Line No.: 2 Column: f

Includes a ($3,716,417) reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

Schedule Page: 122(a)(b) Line No.: 2 Column: g

Includes a $13,432 reclassification from Accumulated Other Comprehensive Income to Adjustments to Retained Earnings (Account 439) to address stranded tax effects resulting from the 2017 Tax Cuts and Jobs Act.

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	18,094,218,407	16,011,771,366
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	2,107,054,949	1,920,946,673
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	20,201,273,356	17,932,718,039
9	Leased to Others		
10	Held for Future Use	13,636,260	13,636,260
11	Construction Work in Progress	620,506,562	539,230,976
12	Acquisition Adjustments	222,385	222,385
13	Total Utility Plant (8 thru 12)	20,835,638,563	18,485,807,660
14	Accum Prov for Depr, Amort, & Depl	8,242,987,294	7,296,145,547
15	Net Utility Plant (13 less 14)	12,592,651,269	11,189,662,113
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,856,526,955	7,121,914,431
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	386,237,954	174,008,731
22	Total In Service (18 thru 21)	8,242,764,909	7,295,923,162
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	222,385	222,385
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,242,987,294	7,296,145,547

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,411,060,055				671,386,986	3
					4
					5
64,844,775				121,263,501	6
					7
1,475,904,830				792,650,487	8
					9
					10
25,710,752				55,564,834	11
					12
1,501,615,582				848,215,321	13
633,503,896				313,337,851	14
868,111,686				534,877,470	15
					16
					17
628,449,243				106,163,281	18
					19
					20
5,054,653				207,174,570	21
633,503,896				313,337,851	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
633,503,896				313,337,851	33

Schedule Page: 200 Line No.: 21 Column: c

The amortization of other utility plant within account 111 includes the following:

Intangible Plant	$ 88,728,122
Nuclear Production Plant	77,859,462
Other Production	4,949,269
Hydraulic Production Plant-Conventional	2,471,878
Total Amort of Other Utility Plant - Electric	$174,008,731

Schedule Page: 200 Line No.: 32 Column: c

The amortization of plant acquisition adjustment within account 115 includes the following:

Transmission	$ 222,385

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	6,027,078	10,969,386
3	Nuclear Materials	159,520,564	51,628,535
4	Allowance for Funds Used during Construction	16,810,089	10,375,815
5	(Other Overhead Construction Costs, provide details in footnote)	55,092	44,813
6	SUBTOTAL (Total 2 thru 5)	182,412,823	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		125,750
9	In Reactor (120.3)	535,339,673	82,977,581
10	SUBTOTAL (Total 8 & 9)	535,339,673	
11	Spent Nuclear Fuel (120.4)	1,979,659,426	65,722,328
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	2,294,997,690	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	402,414,232	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
	15,681,644	1,314,820	2
	57,293,454	153,855,645	3
	9,079,912	18,105,992	4
	55,527	44,378	5
		173,320,835	6
			7
	125,750		8
	65,337,888	552,979,366	9
		552,979,366	10
	1,281,375	2,044,100,379	11
			12
-121,888,518		2,416,886,208	13
		353,514,372	14
			15
			16
			17
			18
			19
			20
			21
			22

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

Classified to Account 120.2 and 120.3

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

Classified to Account 120.2 and 120.3

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

Classified to Account 120.2 and 120.3

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

Classified to Account 120.2 and 120.3

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

Consists of Adminstration and General costs

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

Consists of transfers from 120.1, and direct trailing charges to asset after in-service

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

Transferred to Account 120.3

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

Transferred to Account 120.4

Schedule Page: 202 Line No.: 11 Column: e

Transferred to Account 120.3

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	237,075,386	1,614,699
4	(303) Miscellaneous Intangible Plant	112,279,221	36,003,167
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	349,354,607	37,617,866
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,562,397	
9	(311) Structures and Improvements	288,809,847	7,421,223
10	(312) Boiler Plant Equipment	1,443,265,896	30,545,878
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	306,848,864	20,556,650
13	(315) Accessory Electric Equipment	185,465,429	2,350,212
14	(316) Misc. Power Plant Equipment	54,044,904	71,294
15	(317) Asset Retirement Costs for Steam Production	5,485,922	-16,991,283
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,292,483,259	43,953,974
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,762,362	
19	(321) Structures and Improvements	558,688,626	13,375,547
20	(322) Reactor Plant Equipment	1,719,703,403	121,654,588
21	(323) Turbogenerator Units	486,041,178	97,437,213
22	(324) Accessory Electric Equipment	489,161,601	28,636,650
23	(325) Misc. Power Plant Equipment	206,700,285	441,882
24	(326) Asset Retirement Costs for Nuclear Production	-6,803,320	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	3,455,254,135	261,545,880
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,693,076	
28	(331) Structures and Improvements	1,387,646	833
29	(332) Reservoirs, Dams, and Waterways	10,829,865	429,783
30	(333) Water Wheels, Turbines, and Generators	10,057,492	171,881
31	(334) Accessory Electric Equipment	3,256,971	
32	(335) Misc. Power PLant Equipment	60,825	
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	27,285,875	602,497
36	D. Other Production Plant		
37	(340) Land and Land Rights	21,937,508	-648
38	(341) Structures and Improvements	261,655,657	5,488,844
39	(342) Fuel Holders, Products, and Accessories	88,616,350	10,721,661
40	(343) Prime Movers		
41	(344) Generators	2,181,657,318	87,939,941
42	(345) Accessory Electric Equipment	271,898,545	15,705,211
43	(346) Misc. Power Plant Equipment	31,442,105	1,437,455
44	(347) Asset Retirement Costs for Other Production	77,834,222	6,409,266
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,935,041,705	127,701,730
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	8,710,064,974	433,804,081

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	162,173,725	3,464,361
49	(352) Structures and Improvements	106,998,284	10,288,417
50	(353) Station Equipment	1,215,136,224	42,712,680
51	(354) Towers and Fixtures	118,435,291	-167,047
52	(355) Poles and Fixtures	1,381,960,427	18,828,149
53	(356) Overhead Conductors and Devices	541,316,312	51,662,748
54	(357) Underground Conduit	28,976,307	12,045
55	(358) Underground Conductors and Devices	37,226,577	89,649
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,592,396,576	126,891,002
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	17,370,602	112,060
61	(361) Structures and Improvements	51,235,467	2,130,172
62	(362) Station Equipment	644,116,318	15,091,729
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	414,173,105	27,889,440
65	(365) Overhead Conductors and Devices	470,521,343	25,363,944
66	(366) Underground Conduit	301,059,832	9,980,151
67	(367) Underground Conductors and Devices	1,140,877,197	51,683,116
68	(368) Line Transformers	449,296,730	32,581,240
69	(369) Services	307,693,529	11,750,736
70	(370) Meters	109,165,185	5,382,405
71	(371) Installations on Customer Premises	22,705,174	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	69,173,144	4,611,989
74	(374) Asset Retirement Costs for Distribution Plant	3,770,269	8,460,769
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,001,157,895	195,037,751
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	4,484,101	
87	(390) Structures and Improvements	65,187,003	8,425,476
88	(391) Office Furniture and Equipment	65,834,042	4,517,677
89	(392) Transportation Equipment	163,673,617	13,280,078
90	(393) Stores Equipment	1,631,738	
91	(394) Tools, Shop and Garage Equipment	89,901,366	8,730,298
92	(395) Laboratory Equipment	2,997,571	178,132
93	(396) Power Operated Equipment	46,104,121	4,655,427
94	(397) Communication Equipment	102,354,925	15,845,578
95	(398) Miscellaneous Equipment	3,336,683	30,302
96	SUBTOTAL (Enter Total of lines 86 thru 95)	545,505,167	55,662,968
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	545,505,167	55,662,968
100	TOTAL (Accounts 101 and 106)	17,198,479,219	849,013,668
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	17,198,479,219	849,013,668

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			238,690,085		3
9,453,519			138,828,869		4
9,453,519			377,518,954		5
					6
					7
			8,562,397		8
4,289,575			291,941,495		9
13,080,002			1,460,731,772		10
					11
2,693,934		-250,076	324,461,504		12
750,946			187,064,695		13
313,358		84,854	53,887,694		14
-13,806,983			2,301,622		15
7,320,832		-165,222	2,328,951,179		16
					17
			1,762,362		18
1,115,961		-1,206,726	569,741,486		19
6,894,554		6,687,377	1,841,150,814		20
2,629,062			580,849,329		21
1,848,222			515,950,029		22
432,465		-84,854	206,624,848		23
			-6,803,320		24
12,920,264		5,395,797	3,709,275,548		25
					26
			1,693,076		27
			1,388,479		28
193,367			11,066,281		29
73,631			10,155,742		30
			3,256,971		31
			60,825		32
					33
					34
266,998			27,621,374		35
					36
81,848		8,686,818	30,541,830		37
648,828		145,443	266,641,116		38
2,532,482		-65,244,551	31,560,978		39
		139,802,454	139,802,454		40
2,747,445		-82,324,109	2,184,525,705		41
353,213		-924,214	286,326,329		42
			32,879,560		43
			84,243,488		44
6,363,816		141,841	3,056,521,460		45
26,871,910		5,372,416	9,122,369,561		46

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
10,132,064		-115,331	155,390,691		48
165,875		-148,846	116,971,980		49
5,643,840		-150,831	1,252,054,233		50
125,948			118,142,296		51
1,073,328		-5,906	1,399,709,342		52
-567,196		7,430	593,553,686		53
47,205			28,941,147		54
117			37,316,109		55
					56
			173,429		57
16,621,181		-413,484	3,702,252,913		58
					59
7,119		128,440	17,603,983		60
423,430		246,450	53,188,659		61
5,689,075		150,898	653,669,870		62
					63
1,115,897		7,758	440,954,406		64
4,475,795			491,409,492		65
220,514			310,819,469		66
3,841,671			1,188,718,642		67
13,028,571			468,849,399		68
385,760			319,058,505		69
7,435,669			107,111,921		70
22,705,174					71
					72
565,508			73,219,625		73
			12,231,038		74
59,894,183		533,546	4,136,835,009		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			4,484,101		86
107,445		1,206,726	74,711,760		87
5,902,021			64,449,698		88
2,370,988			174,582,707		89
			1,631,738		90
45,193			98,586,471		91
31,275			3,144,428		92
			50,759,548		93
172,388		1,281	118,029,396		94
5,230			3,361,755		95
8,634,540		1,208,007	593,741,602		96
					97
					98
8,634,540		1,208,007	593,741,602		99
121,475,333		6,700,485	17,932,718,039		100
					101
					102
					103
121,475,333		6,700,485	17,932,718,039		104

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

This footnote also applies to the following pages, lines and columns:
Schedule Page: 205 Line No: 46 Column: g
Schedule Page: 207 Line No: 58 Column: g
Schedule Page: 207 Line No: 75 Column: g
Schedule Page: 207 Line No: 99 Column: g

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

Schedule Page: 204 Line No.: 39 Column: g

Account 342 Fuel Holders, Producers , and Accessories	$27,432,076
Account 348 Energy Storage, Equipment - Production	4,128,902
	$31,560,978

Schedule Page: 204 Line No.: 58 Column: b

Transmission Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 350 - Land & Land Rights	37,124	-	-	-	-	37,124
Account 352 - Structures & Improvements	14,149,096	-	-	-	-	14,149,096
Account 353 - Station Equipment	58,571,739	-	(734,171)	-	(655,915)	57,181,653
Account 354 - Towers & Fixtures	5,303,463	(167,047)	-	-	-	5,136,416
Account 355 - Poles & Fixtures	12,479,826	(2,364,467)	-	-	-	10,115,359
Account 356 - Overhead Conductors & Devices	847,830	2,550,538	-	-	-	3,398,368

Schedule Page: 204 Line No.: 75 Column: b

Distribution Serving Production

	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
Account 361 - Structures & Improvements	838,281	-	-	-	-	838,281
Account 362 - Station Equipment	2,692,338	-	(29,179)	-	-	2,663,159

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25	Nuclear Dry Storage Casks, Prairie Island Nuc Gen Pt	2017	2020	13,560,940
26				
27	Koch Refinery Trans Substation	2018	2019	75,320
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46	Footnote from page 106b			
47	Total			13,636,260

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	FXW-G100-Foxtail Wind Farm	106,950,507
2	BS1-G100-Blazing Star I Wind Farm	84,597,890
3	CRW G100-Crowned Ridge BOT Wind Far	54,139,462
4	DKR0 Dakota Range Wind Turbines	40,911,253
5	ADMS SW MN	22,920,708
6	LBW Lake Benton Wind Farm	21,267,094
7	PI Proc Controls Repl	13,272,600
8	MNGP DAS & PPCS Rplc	7,533,714
9	Purch ADMS EL Net Server GO MN	7,223,191
10	BS1-Blazing Star I Wind Farm TSG SU	6,142,143
11	SE Solar Garden Extensions - E	5,985,776
12	FXW G100-Foxtail Wind Farm TSG Sub	5,656,970
13	ANS3C U3 Major Overhaul	5,200,247
14	Add third transformer at Nordi	5,048,442
15	PI 1R Transformer Replacement	4,794,448
16	PI 123 Cooling Tower Rebuild	4,779,074
17	8th Street Reloc MH and Ductline	4,191,105
18	PI-9 TN-40 Casks(39-47)	4,102,244
19	PI ISFSI Expansion	3,653,172
20	5571 MPR RED 2nd 115kV Circuit Line	3,638,977
21	MN LED Streetlight Replacement	3,540,345
22	PI 12 Reactor Coolant Pump Refurb	3,266,038
23	MNGP EDG Rplc & Voltage Reg	3,118,477
24	PI Capital Maintenance Work	2,827,989
25	MN LED Post Top Conversion	2,619,105
26	Red River-Maple River Sub	2,566,472
27	HBC8C U8 Hot Gas Path	2,298,408
28	FBW G100-Freeborn Wind Farm	2,270,347
29	Install Fifth Street Switchgea	2,264,091
30	0839 MPR RED Reposition Cleanup	2,159,827
31	Solar Garden Ext - WBL	2,030,020
32	500MCM Cable Replacement for N	1,848,716
33	733 Minnkota Kelso Refurb line	1,833,878
34	Install 2nd tansformer at Sauk Rive	1,802,237
35	MN Mobile TR/Subs Reserve 2014	1,797,948
36	69kV Great River Ln Ext line	1,735,972
37	MN - UG Conversion/Rebuild Blanket	1,726,146
38	J460 Blazing Star 1 Wind Interc	1,712,914
39	Huntley Wilmarth Precertification	1,651,232
40	MN - URD Cable Replacement Blanket	1,640,337
41	NSPM Transmission UAV	1,545,986
42	MT Surveillance Test Interval Prg	1,507,774
43	TOTAL	539,230,976

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BS2-G100-Blazing Star II Wind Farm	1,477,560
2	MN-Solar Garden Sub Work	1,407,091
3	MN - UG Extension Blanket	1,400,162
4	MNGP Obsolete EQ RFO29	1,337,434
5	PI NFPA 805-10 Loss OCT 4KV Br	1,228,662
6	MN - OH Relocation Blanket	1,214,428
7	PI PRA Model Revision-SFCP	1,210,479
8	PI BFB Inspection Interval LAR	1,201,031
9	MN - UG Services Renewal Blanket	1,161,446
10	MNGP NEI 09-05 Security Compli	1,117,281
11	SHCJC Coal Yard Emerson DCS 2018	1,070,759
12	NSPM Physical Security Comm	1,031,942
13	MN - OH Rebuild Blanket	1,005,202
14		
15	Minor Projects	63,594,223
16		
17		
18		
19		
20		
21		
22		
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24		
25		
26		
27		
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31		
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33		
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35		
36		
37		
38		
39		
40		
41	Footnote from Page 106b	
42		
43	TOTAL	539,230,976

Schedule Page: 216.1 Line No.: 41 Column: b

Construction Work in Progress (Account 107). The Form 1 reports the total Company construction work in progress (CWIP) balances at the end of the year. The Company uses a 13-month average calculation for the specific CWIP project balances included in the formula. The Company can only include CWIP in the formula related to the following specific projects, the balances of which could be a component of the amounts reported on page 216: the three projects in Group 1 of the CapX2020 Project - Twin Cities-Brookings County, Twin Cities-Fargo, and Twin Cities-LaCrosse.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	6,752,582,070	6,752,582,070		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	534,493,264	534,493,264		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-20,970,282	-20,970,282		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	13,567,101	13,567,101		
7	Other Clearing Accounts	161,246	161,246		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	527,251,329	527,251,329		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	125,827,563	125,827,563		
13	Cost of Removal	30,388,429	30,388,429		
14	Salvage (Credit)	16,777,481	16,777,481		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	139,438,511	139,438,511		
16	Other Debit or Cr. Items (Describe, details in footnote):	-32,287,440	-32,287,440		
17					
18	Book Cost or Asset Retirement Costs Retired	13,806,983	13,806,983		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	7,121,914,431	7,121,914,431		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,489,587,405	1,489,587,405		
21	Nuclear Production	1,925,946,697	1,925,946,697		
22	Hydraulic Production-Conventional	12,101,811	12,101,811		
23	Hydraulic Production-Pumped Storage				
24	Other Production	916,159,745	916,159,745		
25	Transmission	899,158,946	899,158,946		
26	Distribution	1,619,587,127	1,619,587,127		
27	Regional Transmission and Market Operation				
28	General	259,372,700	259,372,700		
29	TOTAL (Enter Total of lines 20 thru 28)	7,121,914,431	7,121,914,431		

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

Net change in RWIP	$ (26,828,119)
Net Transfers	(3,134,995)
(Gain)/Loss	(975,603)
Gain shared with customers	(1,348,723)
Total	$ (32,287,440)

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

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

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

Schedule Page: 219 Line No.: 25 Column: c

Transmission Serving Production $ 37,382,088

Schedule Page: 219 Line No.: 26 Column: c

Distribution Serving Production $ 2,393,177

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

	"Non-Legal" ARO Balances
Steam Production	$ 97,982,065
Nuclear Production	(87,061,816)
Hydraulic Production-Conventional	1,840,081
Other Production	45,508,135
Transmission	116,381,959
Distribution	221,887,694
General	(499,096)
Total	$ 396,039,022

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	UNITED POWER & LAND CO.			
2	Common Stock-par $100 per share			4,020,000
3	Additional Paid in Capital			399,724
4	Undistributed earnings (loss) since acquisition			-3,486,659
5	SUBTOTAL			933,065
6				
7	NSP NUCLEAR CO.			
8	Contributed Capital			963,198
9	Undistributed earnings (loss) since acquisition			549,913
10	SUBTOTAL			1,513,111
11				
12				
13				
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15				
16				
17				
18				
19				
20				
21				
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41				
42	Total Cost of Account 123.1 $ 5,532,860		TOTAL	2,446,176

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		4,020,000		2
	149,938	549,662		3
-100,532		-3,587,191		4
-100,532	149,938	982,471		5
				6
				7
		963,198		8
22,720		572,633		9
22,720		1,535,831		10
				11
				12
				13
				14
				15
				16
				17
				18
				19
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				41
-77,812	149,938	2,518,302		42

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 3 Column: f

Contribution of Capital From Parent Company	$	150,000
Annual Allocation of Unitary Tax (Benefit)/Detriment		(62)
	$	149,938

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	97,129,106	90,364,543	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	47,056,876	46,024,126	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	164,146,973	132,176,539	Electric
8	Transmission Plant (Estimated)	1,145,534	1,296,801	Electric
9	Distribution Plant (Estimated)	2,675,885	1,269,220	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-6,570,632	-5,523,276	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	208,454,636	175,243,410	
13	Merchandise (Account 155)	752,710	1,094,063	
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18	note re: page 106 formula rates			
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	306,336,452	266,702,016	

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

Includes a credit of $2,859,505 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of $3,711,127 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

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

Includes a credit of $2,829,233 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of $2,694,043 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.

Schedule Page: 227 Line No.: 18 Column: a

Materials & Supplies (Accounts 154 and 163). The Form 1 reports the materials and supplies balances at the beginning and end of the year. The Company uses the average of the beginning and end of the year materials and supplies balances in the formula rate (see page 106).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	842,707.00		95,252.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	532.00			
6					
7					
8	Purchases/Transfers:	-4,341.00			
9					
10					
11					
12					
13					
14					
15	Total	-4,341.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	19,357.00			
19	Other:				
20	Adjust Balance				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	819,541.00		95,252.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	926.00		926.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	926.00			
40	Balance-End of Year			926.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	926.00	74		
45	Gains		74		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
95,252.00		69,262.00		1,731,550.00		2,834,023.00		1
								2
								3
		25,990.00		95,252.00		121,242.00		4
						532.00		5
								6
								7
						-4,341.00		8
								9
								10
								11
								12
								13
								14
						-4,341.00		15
								16
								17
						19,357.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
95,252.00		95,252.00		1,826,802.00		2,932,099.00		29
								30
								31
								32
								33
								34
								35
926.00		926.00		44,397.00		48,101.00		36
				1,850.00		1,850.00		37
								38
				926.00		1,852.00		39
926.00		926.00		45,321.00		48,099.00		40
								41
								42
								43
						926.00	74	44
							74	45
								46

Schedule Page: 228   Line No.: 44   Column: m

Proceeds from SO2 allowance sales from plants owned by NSP-Minnesota. This amount will not agree to Account 411.8 on the Income Statement (see page 114-117) due to proceeds from the sale of Renewable Energy Credits, the sharing of the sale proceeds through the FERC-approved Interchange Agreement, and the specific regulatory treatment prescribed by the Minnesota, North Dakota, and South Dakota state regulatory commissions.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	36,590.00		15,980.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA	91.00			
6					
7					
8	Purchases/Transfers:	-45.00			
9					
10					
11					
12					
13					
14					
15	Total	-45.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	10,775.00			
19	Other:				
20	Adjust Balance				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	25,861.00		15,980.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
15,980.00						68,550.00		1
								2
								3
		15,980.00		15,980.00		31,960.00		4
						91.00		5
								6
								7
						-45.00		8
								9
								10
								11
								12
								13
								14
						-45.00		15
								16
								17
						10,775.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
15,980.00		15,980.00		15,980.00		89,781.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Prairie Island	78,884,915		Various	2,876,872	58,834,686
22	Extended Power Uprate project					
23	MN Docket E-002/CN-08-509					
24						
25	Benson Biomass PPA Termination	49,796,637		407	2,304,838	47,491,799
26	MN Docket E-002/M-17-530					
27	ND Docket PU-17-270 and					
28	and PU-17-271					
29	SD Docket EL18-027					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	128,681,552			5,181,710	106,326,485

Schedule Page: 230 Line No.: 21 Column: a

In 2009, the Minnesota Public Utilities Commission (MPUC) granted NSP-Minnesota a Certificate of Need for an Extended Power Uprate (EPU) project at the Prairie Island (PI) nuclear generating plant. The total estimated cost of the EPU was $294 million, of which approximately $78.9 million had been incurred through 2012, including AFUDC of approximately $12.8 million. Subsequently, NSP-Minnesota made a change of circumstances filing notifying the MPUC that there were changes in the size, timing and cost estimates for this project, revisions to economic and project design analysis and changes due to the estimated impact of revised scheduled outages. The information indicated reductions to the estimated benefit of the uprate project. As a result, NSP-Minnesota concluded that further investment in this project would not benefit customers. In February 2013, the MPUC issued an order terminating the CON for the PI EPU project.

In its 2014 Minnesota retail electric rate case under MPUC Docket 13-868, NSP-Minnesota received recovery of approximately $59 million of deferred costs plus a debt-only return of 2.24 percent, to be recovered over 20.3 years.

On Nov. 19, 2015, the FERC approved a request under FERC Docket ER15-698 to allocate a portion of the amortization and debt-only return to NSP-Wisconsin under the Interchange Agreement. Approximately $12 million will be amortized, beginning on Jan. 1, 2016 and continuing for 18.3 years.

NSP-Minnesota intends to seek recovery of North Dakota and South Dakota jurisdictional amounts in future rate proceedings.

Schedule Page: 230 Line No.: 21 Column: b

Transfers from Account No. 107 during 2012	$ 77,690,096
Transfers from Account No. 107 during 2013	1,194,819
	$ 78,884,915

Schedule Page: 230 Line No.: 21 Column: d

Account No. 426.5 - accretion during 2018	(492,880)
Account No. 407 - amortization during 2018	3,369,752
	$ 2,876,872

Schedule Page: 230 Line No.: 25 Column: a

On Aug. 28, 2017, NSP-Minnesota filed a Section 203 application with FERC (Docket No. EC17-166-000) under which Benson Power, LLC ("Benson Power") would sell and NSP-Minnesota would acquire a 62.3 MW (nameplate) biomass-fired electric generation plant, terminate a multi-year Power Purchase Agreement between NSP-Minnesota and Benson Power, and then shut down and dismantle the Benson Power Facility and remediate the plant site. The transaction was approved by the Commission on Feb. 23, 2018, and on June 29, 2018 the transaction with Benson Power closed. All plant acquisition, plant retirement costs, and contract termination costs will be recovered in the NSP-Minnesota and NSP-Wisconsin retail jurisdictions. The NSP-Minnesota retail orders are as follows:

— Minnesota - *In the Matter of Petition of Northern States Power Company for Approval to Terminate the Power Purchase Agreement with Benson Power, LLC, Acquire the Benson Power Biomass Plant, and Subsequently Close the Facility,* MPUC Docket No. E002/M-17-530, Order Approving Petitions, Approving Cost Recovery Proposals and Granting Variances (January 23, 2018) and Order Denying Reconsideration (March 28, 2018). Amortization period is July 1, 2018 through Sept. 10, 2028 (or 122.33

months).

- North Dakota - *Northern States Power Company, Application for Advance Determination of Prudence and Application for Authority for Deferred Accounting*, NDPSC Case Nos. PU-17-270 and PU-17-271 (June 30, 2017), Order Approving Petitions and Settlement Agreement (June 27, 2018). Amortization period is July 1, 2018 through June 30, 2029 (or 132 months).

- South Dakota - *Request for Approval of Deferred Accounting for Certain Biomass Transaction Costs*, Docket No. EL18-027 (May 31, 2018), Order Approving Deferred Accounting Treatment (June 28, 2018). Amortization period is Jan. 1, 2019 through Sept. 30, 2028 (or 117 months).

On June 14, 2018, as supplemented on July 2, 2018, the NSP Companies filed modifications to certain exhibits in the Interchange Agreement to allow NSP-Minnesota to allocate to NSP-Wisconsin and recover a share of the costs incurred by NSP-Minnesota for the Benson Transaction. These modifications were accepted effective June 29, 2018, by letter order dated August 10, 2018 in Docket No. ER18-1786-000.

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	J432 Facility Study	62,067	561.7	62,067	561.7
23	J432 Facility Study			14,679	232
24	J460 Facility Study	55,018	561.7	55,018	561.7
25	J460 Facility Study			8,056	232
26	A698/F115 Facility Study-PO 21555	24,480	561.7	24,480	561.7
27	A698/F115 Facility Study-PO 21555			9,946	232
28	J460/J526 Hazel Creek Trnsfm Upgre	14,234	561.7	14,234	561.7
29	J460/J526 Hazel Creek Trnsfm Upgre			5,991	232
30	J523 Adams Substation Line Terminn	12,003	561.7	12,003	561.7
31	J523 Adams Substation Line Terminn			5,531	232
32	J523 Adams SubTransformer Replace	14,326	561.7	14,326	561.7
33	J523 Adams SubTransformer Replace			7,841	232
34	J526 Line 0900 rebuild	11,314	561.7	11,314	561.7
35	J526 Line 0900 rebuild			2,500	232
36	J789/G162 Fenton FaS	1,814	561.7	1,814	561.7
37	J512 Wind Interco FaS	6,371	561.7	6,371	561.7
38	J587 Blazing Star 2 Fas Wind	1,771	561.7	1,771	561.7
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Conservation and Energy Management Program Costs	31,512,526	138,450,670	Various	142,632,118	27,331,078
2	Minnesota Electric					
3	- MN Docket E-002/M-18-240					
4	- Generally amortized over 12 month					
5	period following the expenditure					
6						
7	Conservation and Energy Management Program Costs	120,619	804,317	908	920,028	4,908
8	South Dakota Electric					
9	- SD Docket EL17-019					
10	- Generally amortized over 12 month					
11	period following the expenditure					
12						
13	Net of Tax AFUDC in Plant Adjustments	118,964,207		Various	1,365,271	117,598,936
14						
15	South Dakota Ratemaking Differences	3,493,250	341,000	405	414,000	3,420,250
16	- SD Docket F-3382					
17	- SD Docket F-3422					
18						
19	Renewable Development Fund Rider	45,795,409	31,435,116	407.3	38,071,338	39,159,187
20	- MN Docket E-002/M-18-628					
21						
22	Asset Retirement Recovery	2,156,150,029	82,708,536			2,238,858,565
23						
24	Minnesota Gas State Energy Policy Rider	255,074	1,396,593	407.3	1,574,353	77,314
25	- MN Docket G-002/M-17-174					
26						
27	Minnesota Transmission Cost Recovery Rider	784,737	88,413,801	407.3	89,198,538	
28	- MN Docket E-002/M-17-797					
29	- MN Docket E-002/M-17-1156					
30						
31	Power Contract Valuation Adjustment	104,179,468		Various	14,115,941	90,063,527
32						
33	Costs to Relocate Facilities Underground	718,359	162,747	142	341,045	540,061
34	- MN Docket E-002/M-15-826					
35						
36	Private Fuel Storage	2,641		407.3	2,641	
37	- Amortized over 6 years					
38	- SD Docket EL14-058 (Amortized 01/2010-01/2018)					
39						
40	Minnesota Deferred Electric Commodity Costs	4,559,386		254	4,559,386	
41	- MN Docket E-002/M-14-364					
42						
43						
44	TOTAL	3,562,449,742	688,271,184		516,980,801	3,733,740,125

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Mankato/Cannon Falls Lease Normalization	41,077,194	1,052,554	253	2,787,190	39,342,558
2						
3	Deferred Nuclear Outage Costs	68,985,083	34,361,997	Various	53,180,059	50,167,021
4	- Generally amortized over 23-24 months					
5	- MN Docket E-002/M-07-1489					
6	- ND Docket PU-07-774					
7	- SD Docket EL07-035					
8						
9	Benefit Cost Recovery Deficit	432,257,111	49,659,681	184	34,551,415	447,365,377
10						
11	Transmission Formula Rates	12,982,869	3,298,561	Various	5,322,420	10,959,010
12						
13	Sherco 3 Depreciation Deferral	8,717,430		407.3	667,355	8,050,075
14	-MN Docket E-002/GR-15-826					
15	- Amortized over 21 years (01/2014-12/2035)					
16						
17	Theoretical Depreciation Reserve Surplus	278,506,682		407.3	10,673,023	267,833,659
18	-MN Docket E-002/GR-17-147					
19						
20	North Dakota Transmission Cost Recovery Rider	72,320	7,334,801	407.3	7,407,121	
21	- ND Docket PU-17-365					
22						
23	Gas Utility Infrastructure Cost Rider	27,091,650	18,549,141	Various	18,242,414	27,398,377
24	- MN Docket G-002/M-17-787					
25						
26	Minnesota Electric Vehicle Tariff	181,991	237,354			419,345
27	- MN Docket E-002/M-17-879					
28						
29	North Dakota Environmental Cleanup	19,720,532	9,152,807	Various	13,371,640	15,501,699
30	- ND Docket PU-17-894					
31						
32	South Dakota Property Tax Collected in the	410,959	2,293,339	Various	2,704,298	
33	Fuel Clause Adjustment					
34	- SD Docket EL14-058					
35						
36	Minnesota Revenue Decoupling 2017	27,095,792		407.3	21,363,351	5,732,441
37	- MN Docket E-002/GR-13-868					
38	- MN Docket E-002/GR-15-826					
39	- Amortized over 1 year (04/2018-03/2019)					
40						
41	2016 Minnesota Deferred Property Tax	16,360,244		407.3	8,180,121	8,180,123
42	- MN Docket E-002/GR-15-826					
43	- Amortized over 2 years (01/2018-12/2019)					
44	TOTAL	3,562,449,742	688,271,184		516,980,801	3,733,740,125

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	2017 Minnesota Sales True-up	22,667,432		407.4	17,682,032	4,985,400
2	- MN Docket E-002/GR-15-826					
3	- Amortized over 1 year (04/2018-03/2019)					
4						
5	Benson Biomass PPA Termination	22,500	50,419,606	557	2,368,336	48,073,770
6	- MN Docket E-002/GR-17-530					
7	- ND Docket PU-17-271					
8						
9	Minnesota LED Streetlighting Deferral	686,612	220,566			907,178
10	- MN Docket E-002/GR-15-826					
11						
12	Nonplant Excess ADIT	133,060,653	20,274,566			153,335,219
13						
14	Renewable*Connect Classic	878,125	3,081,029	142	1,558,450	2,400,704
15	- MN Docket E-002/GR-15-985					
16						
17	Renewable*Connect Government	59,530	388,625	142	340,154	108,001
18	- MN Docket E-002/GR-15-985					
19						
20	South Dakota REC Sales	3,514		Various	3,514	
21	- SD Docket EL12-046					
22						
23	Minnesota Environmental Cleanup	4,868,482		735	4,868,482	
24	- MN Electric E-002/GR-17-894					
25						
26	Electric Low Income Discount Program	161,842		254	161,842	
27	and PowerON Program					
28	- MN Electric E-002/GR-15-826					
29	- MN Electric E-002/M-04-1956					
30						
31	North Dakota Service Quality Program	22,524		254	22,524	
32	- ND Docket PU-11-557					
33	- ND Docket PU-12-813					
34						
35	South Dakota Fuel Clause Adjustment Charge	22,966		254	22,966	
36	- SD Docket EL14-058					
37						
38	Laurentian Biomass PPA Termination		109,482,150	253	18,083,333	91,398,817
39	- MN Electric E-002/M-17-551					
40	- ND Docket PU-17-271					
41	- SD Docket EL18-027					
42						
43						
44	TOTAL	3,562,449,742	688,271,184		516,980,801	3,733,740,125

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Pind Bend Biomass PPA Termination		1,061,911	253	224,102	837,809
2	- MN Electric E-002/M-17-550					
3	- ND Docket PU-17-271					
4	- SD Docket EL18-027					
5						
6	2017 Tax Cuts and Jobs Act - SD Electric		244,424			244,424
7	- SD Docket GE17-003					
8						
9	2018 Minnesota Sales True-up		33,445,292			33,445,292
10	- MN Docket E-002/GR-15-826					
11	- Amortized over 1 year (04/2019-03/2020)					
12						
13						
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43						
44	TOTAL	3,562,449,742	688,271,184		516,980,801	3,733,740,125

Schedule Page: 232 Line No.: 1 Column: d

Accounts charged:	
456	$43,873,011
908	98,759,107
Total	$142,632,118

Schedule Page: 232 Line No.: 13 Column: d

Accounts charged:	
282	$1,351,134
283	14,137
Total	$1,365,271

Schedule Page: 232 Line No.: 31 Column: d

Accounts charged:	
175	$288,734
244	13,827,207
Total	$14,115,941

Schedule Page: 232.1 Line No.: 3 Column: c

Accounts charged:	
517	$1,450,464
519	730,639
520	4,494,799
523	423,834
524	1,505,818
528	420,861
530	13,321,708
531	1,355,030
532	10,658,844
Total	$34,361,997

Schedule Page: 232.1 Line No.: 3 Column: d

Accounts charged:	
517	$4,160,804
519	946,824
520	6,192,624
523	259,501
524	2,510,158
528	425,885
529	20,711
530	20,436,654
531	2,803,101
532	15,423,797
Total	$53,180,059

Schedule Page: 232.1 Line No.: 11 Column: d

Accounts charged:	
456.1	$2,632,629
565	2,689,791
Total	$5,322,420

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

Accounts charged:	
407.4	$13,688,331
856	594,033
863	227,292

870	527
874	3,553,320
880	123,202
887	39,452
892	3,733
893	12,524
Total	$18,242,414

Schedule Page: 232.1 Line No.: 29 Column: d

Accounts charged:

242	$12,121,640
735	1,250,000
Total	$13,371,640

Schedule Page: 232.1 Line No.: 32 Column: d

Accounts charged:

254	$490,338
408.1	2,213,960
Total	$2,704,298

Schedule Page: 232.2 Line No.: 12 Column: f

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	$ 105,370,481	$ 41,251,103	$ 146,621,584
Gas	4,824,794	1,888,841	6,713,635
Total	$ 110,195,275	$ 43,139,944	$ 153,335,219

*For purposes of calculating the the NSP Companies transmission formula rate, the excess non-plant balances (excluding tax gross-up) are as follows. The Company uses the average of the beginning of the year and the end of the year balances in the formula. These balances are being flowed back to customers over various periods consistent with the nature of the item.

	Excess Balance 12/31/2017	Amortization 2018	Excess Balance 12/31/2018
Bad Debts	$ 2,558,792	$ (511,758)	$ 2,047,034
Deferred Rent	1,366,256	(273,251)	1,093,005
Deferred Revenues	289,830	(57,966)	231,864
Economic Development Securities - Write-Off	47,782	(9,556)	38,226
Employee Incentive Plans	1,991,416	(398,283)	1,593,133
Environmental Remediation	22,287	(4,457)	17,830
Federal Net Operating Loss	96,477,646	(4,194,680)	92,282,966
Fuel Tax Credit - Income Addback	2,260	(452)	1,808
Inventory Reserve	495,068	(99,014)	396,054
Litigation Reserve	53,814	(10,763)	43,051
Medical Deductions - Self Insured	232,818	(46,564)	186,254
North Dakota Investment Tax Credit	(15,190,216)	3,038,043	(12,152,173)
North Dakota Investment Tax Credit - Valuation Allowance	15,190,216	(3,038,043)	12,152,173
Performance Recognition Awards	5,462	(1,092)	4,370
Post Employment Benefits - Long Term Disability	1,918,437	(127,896)	1,790,541

Post Employment Benefits - Retiree Medical	6,152,900	(410,193)	5,742,707
Purchased Power Capacity	25,790	(5,158)	20,632
Rate Refund	2,991,364	(598,273)	2,393,091
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	1,830,985	(366,197)	1,464,788
Regulatory Asset/Liability - Transmission Cost Recovery Rider	956,072	(191,214)	764,858
Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	510,520	(102,104)	408,416
Sale of Emission Allowances	10,209	(2,042)	8,167
South Dakota Infrastructure Rider	131,106	(26,221)	104,885
Section 174 - Section 59(e) Adjustment	6,916,430	(1,383,286)	5,533,144
Severance Accrual	30,411	(6,082)	24,329
Solar Rewards Program	3,382,348	(676,470)	2,705,878
State Research and Experimental Credit	(1,017,878)	203,576	(814,302)
State Research Credit - Valuation Allowance	195,296	(39,059)	156,237
Vacation	2,270,232	(454,046)	1,816,186
VEBA	636,056	(127,211)	508,845
Workers Compensation	11,826	(2,365)	9,461
Total Electric	$ 130,495,535	$ (9,922,077)	$ 120,573,458

Schedule Page: 232.2 Line No.: 20 Column: d

Accounts charged:

254	$2,618
557	896
Total	$3,514

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	IPP Power Contract Billing	847,864	8,816	Various	20,965	835,715
2	Adjustments					
3						
4	Conservation and Energy	31,613,897	24,575,710	182.3	30,241,197	25,948,410
5	Management Program Costs					
6	Minnesota Electric Incentive					
7	(Docket E-002/M-18-240)					
8						
9	Conservation and Energy	3,044,770	3,053,510	182.3	3,753,592	2,344,688
10	Management Program Costs					
11	Minnesota Gas Incentive					
12	(Docket G-002/M-18-246)					
13						
14	Federal and State Income	1,673,834	1,515,322	236	1,823,958	1,365,198
15	Taxes Receivable					
16						
17	Federal and State Income	4,302,205	1,048,010	171	4,286	5,345,929
18	Tax Interest Receivable					
19						
20	Debt Issuance Costs	4,000	340,785	181	25,419	319,366
21						
22	2016 Minnesota Electric Retail	1,669,992		928	834,996	834,996
23	Rate Case					
24	- Amortized through Dec. 2019					
25	(Docket E-002/GR-15-826)					
26						
27	North Dakota Electric	1,866,845	108,092			1,974,937
28	Retail Rate Case-Demand Study					
29	and Generation Restack					
30	(Docket PU-12-813)					
31						
32	Future South Dakota Electric	113,169				113,169
33	Retail Rate Case					
34	(Docket EL14-058)					
35						
36	Notes Receivable - 3rd Party	184,295		143	184,295	
37						
38	2018 Minnesota Gas Retail Rate	8,279				8,279
39	Case					
40						
41	2018 South Dakota Electric	3,826	89,881	928	93,707	
42	Retail Rate Case					
43						
44	Prepaids - Facility Fees	1,589,197	15,000	431	471,173	1,133,024
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	46,922,173				40,891,771

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	JOA & Rate Payer Share MTM		357,636			357,636
2						
3	2018 North Dakota Electric		306,398			306,398
4	Retail Rate Case					
5						
6	FIN 48 Long Term Interest		850,166	232	846,140	4,026
7	Receivable					
8						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	46,922,173				40,891,771

Schedule Page: 233 Line No.: 1 Column: d

Accounts charged:

232	$3,294
555	17,638
904	33
Total	$20,965

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric - Plant	183,100,260	195,829,217
3	Electric - Non-Plant	523,050,699	536,988,904
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	706,150,959	732,818,121
9	Gas		
10	Gas	26,114,354	20,204,873
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	26,114,354	20,204,873
17	Other (Specify)	50,833,875	40,011,300
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	783,099,188	793,034,294

Notes

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

Electric Plant Related Only:	Balance at Beginning of Year	Balance at End of Year
Electric Distribution Plant	$103,451,043	$117,591,782
Electric General Plant	655,637	548,166
Electric Intangible Plant	4,816,525	4,204,166
Electric Nuclear Fuel	25,783,915	26,652,048
Electric Nuclear Production Plant	69,335,295	65,274,613
Electric Production Plant	43,725,916	42,356,143
Electric Transmission Plant	40,269,071	40,450,403
Electric Transmission - Production Plant	549,419	537,870
Common (Allocation to Electric)	687,606	729,200
Regulatory Difference - Effect of Rate Changes	(115,176,052)	(110,946,257)
Regulatory Difference - Investment Tax Credit Gross-Up	9,001,885	8,431,083
Total Electric Plant Related Only	$183,100,260	$195,829,217

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

Electric:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$138,181,662	$134,316,526
Bad Debts	5,646,935	6,163,082
Customer Advances	278,876	3,977,711
Deferred Connection Fees	94,761,029	105,938,424
Deferred Rent	3,015,157	2,924,005
Deferred Revenue	639,619	550,288
Economic Development Securities - Write-Off	109,754	104,417
Electric Vehicle Credit	6,968	6,956
Employee Incentive Plans	4,105,569	4,036,902
Employee Stock Ownership Program Dividends	6,605,695	6,670,645
End of Life Nuclear Fuel Amortization	25,783,915	26,652,048
Environmental Remediation	49,186	49,235
Excess Nonplant Accumulated Deferred Income Taxes	14,975,075	13,741,549
Federal Net Operating Loss	120,032,866	0
Fuel Tax Credit - Income Addback	7,943	4,985
Inventory Reserve	1,092,553	764,793
Investment Tax Credit	452,260	452,260
Litigation Reserve	118,760	170,814
Medical Deductions - Self Insured	524,230	611,383
Monticello Extended Power Uprate Writedown	23,663,250	20,789,037
New Hire Retention Credit	51,697	51,546
North Dakota Investment Tax Credit	85,716,216	82,647,239
North Dakota Investment Tax Credit - Valuation Allowance	(81,049,114)	(76,737,862)
North Dakota Investment Tax Credit - Federal Gross-Up	1,240,622	1,592,313
Performance Recognition Awards	12,053	47,757
Post Employment Benefits - Retiree Medical	13,578,683	13,356,931
Post Employment Benefits - Long Term Disability	4,233,751	3,978,153
Purchased Power Capacity	56,915	56,972
Rate Refund	6,601,567	48,097,251
Regulatory Asset/Liability - Prairie Island Extended Power Uprate Cancellation	1,126,653	0
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	4,040,755	2,333,571

Regulatory Asset/Liability - Transmission Cost Recovery Rider	2,109,931	11,009,066
Regulatory Asset/Liability - Transmission Attach O	0	238,060
Regulatory Asset/Liability - Windsource	0	804,181
Regulatory Difference - Effect of Rate Changes	(115,176,052)	(110,946,257)
Regulatory Difference - Investment Tax Credit Gross-Up	9,001,885	8,431,083
Research and Experimentation Credit	52,073,882	56,204,033
Sale of Emission Allowances	22,531	31
Section 174 - Section 59(e) Adjustment	15,120,000	20,918,228
Severance Accrual	67,113	84,652
Solar Rewards Program	7,464,420	4,461,705
South Dakota Infrastructure Tracker	289,335	378,425
State Research Credit	5,877,139	6,351,862
State Research Credit - Valuation Allowance	(1,102,028)	(1,729,739)
State Tax Deduction Cash vs. Accrual	268,124	1,262,092
Vacation Accrual	5,010,118	4,860,479
VEBA	0	1,401,025
Wind Production Tax Credit	249,437,361	325,691,722
Workers Compensation	26,100	48,542
Total Electric	$706,150,959	$732,818,121

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

Amortization of Excess ADIT (Electric only) included in 410.1 is $3,489,324.

	2018 ARAM
Decommissioning	-
Electric Distribution Plant	1,281,180
Electric General Plant	8,250
Electric Intangible Plant	244,874
Electric Nuclear Fuel	-
Electric Production Plant	1,578,622
Electric Transmission Plant	364,453
Electric Transmission-Production Plant	3,137
Common (Allocation to Electric)	8,808
Total Electric	3,489,324

Common allocation for financial reporting may be different than for rate making.

Common (Unallocated)	9,593

The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

Excess (Electric only)	Dec. 31, 2018 Excess	Dec. 31, 2018 Gross up	Dec. 31, 2018 Total Regulatory
Flow Through	521,619	204,207	725,826
Other Basis Differences (Unprotected)	(80,253,812)	(31,418,271)	(111,672,083)
	(79,732,193)	(31,214,064)	(110,946,257)

Includes Non-Utility and Common Allocated. The common allocation for the financial reporting is different from the allocation used in rate making.

Non-utility			
Other Basis Differences (Unprotected)	(8)	(3)	(11)
	(8)	(3)	(11)
Common (allocated)			
Other Basis Differences (Unprotected)	(118,835)	(46,522)	(165,357)
	(118,835)	(46,522)	(165,357)
Common (unallocated)			
Other Basis Differences (Unprotected)	(311,081)	(121,784)	(432,865)
	(311,081)	(121,784)	(432,865)

Schedule Page: 234 Line No.: 16 Column: c

Gas:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$2,706,851	$2,811,017
Bad Debts	333,562	435,111
Deferred Connection Fees	10,300,853	10,516,629
Deferred Rent	230,091	228,561
Deferred Revenue	48,694	0
Economic Development Securities - Write-Off	6,483	7,372
Electric Vehicle Credit	532	544
Employee Incentive Plans	341,750	348,780
Employee Stock Ownership Program Dividends	2,228,951	2,371,287
Environmental Remediation	5,257,966	1,701,973
Excess Nonplant Accumulated Deferred Income Taxes	737,417	688,148
Federal Net Operating Loss	6,194,438	0
Fuel Tax Credit - Income Addback	606	390
Inventory Reserve	83,374	59,782
Litigation Reserve	7,015	12,059
Lower of Cost or Market on Gas Inventories	332,033	387,258
Medical Deduction - Self Insured	43,637	52,822
New Hire Retention Credit	4,303	4,454
Performance Recognition Awards	1,003	4,126
Post Employment Benefits - Retiree Medical	1,130,297	1,154,011
Post Employment Benefits - Long Term Disability	352,420	343,704
Public Utility Conservation Investment Programs	0	819,898
Rate Refund	0	1,582,989
Regulatory Difference - Effect of Rate Changes	(6,317,355)	(6,049,098)
Regulatory Difference - Investment Tax Credit	510,797	469,397
Gross-Up		
Section 174 - Section 59(e) Adjustment	1,153,831	1,635,118

Severance Accrual	5,587	7,314
State Tax Deduction Cash vs. Accrual	0	66,052
Vacation Accrual	417,045	419,935
VEBA	0	121,046
Workers' Compensation	2,173	4,194
Total Gas	$26,114,354	$20,204,873

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

Other:	Balance at Beginning of Year	Balance at End of Year
Avoided Tax Interest	$26	$1,141
Contributions Carryover	426,123	791,395
Deferred Compensation Plan Reserve	4,421,661	5,110,390
Federal Alternative Minimum Tax Credit	933,754	1,585,871
Federal Alternative Minimum Tax Credit - Valuation Allowance	0	(57,635)
Federal Net Operating Loss	7,787,843	0
Low Income Housing Credit	3,344,790	3,344,790
Minnesota Alternative Minimum Tax Credit	143,158	161,287
Minnesota Net Operating Loss	21,393,981	18,046,950
North Dakota Net Operating Loss	669,266	18,228
Nonqualified Pension Plans	594,277	592,440
Other Comprehensive Income	9,672,015	9,040,442
Partnership Passthrough	320,915	330,333
Performance Share Plan	979,135	900,276
Regulatory Difference - Effect of Rate Changes	(16)	(16)
State Tax Deduction Cash vs. Accrual	144,832	145,408
Wisconsin Net Operating Loss	2,115	0
Total Other	$50,833,875	$40,011,300

Schedule Page: 234 Line No.: 18 Column: c

Refer to FERC page 232 for NSPM's regulatory asset related to nonplant excess ADIT.

Schedule Page: 234 Line No.: 1 Column:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	-All NSP-Minnesota common stock is owned by			
3	parent, Xcel Energy Inc.	5,000,000	0.01	
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
1,000,000	10,000					3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid-in Capital	
2	Contribution of capital by parent company	3,144,966,526
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40	TOTAL	3,144,966,526

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
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21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2	FIRST MORTGAGE BONDS SERIES DUE:		
3			
4			
5	2.15% Aug. 15, 2022 First Mortgage Bonds	300,000,000	3,088,686
6			456,000 D
7			
8	7.125% July 1, 2025 First Mortgage Bonds	250,000,000	1,898,333
9			2,330,000 D
10			
11	6.50% March 1, 2028 First Mortgage Bonds	150,000,000	1,474,885
12			1,761,001 D
13			
14	5.25% July 15, 2035 First Mortgage Bonds	250,000,000	3,032,114
15			485,000 D
16			
17	6.25% June 1, 2036 First Mortgage Bonds	400,000,000	4,877,065
18			1,404,000 D
19			
20	6.20% July 1, 2037 First Mortgage Bonds	350,000,000	4,336,843
21			1,988,000 D
22			
23	5.35% Nov. 1, 2039 First Mortgage Bonds	300,000,000	4,153,918
24			570,000 D
25			
26	4.85% Aug. 15, 2040 First Mortgage Bonds	250,000,000	3,019,146
27			707,500 D
28			
29	3.40% Aug 15, 2042 First Mortgage Bonds	500,000,000	6,272,718
30			3,820,000 D
31			
32	2.60% May 15, 2023 First Mortgage Bonds	400,000,000	4,524,626
33	TOTAL	5,000,000,000	90,323,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			732,000 D
2			
3	4.125% May 15, 2044 First Mortgage Bonds	300,000,000	3,821,358
4			873,000 D
5			
6	3.60% Sep 15, 2047 First Mortgage Bond	600,000,000	8,795,587
7			5,982,000 D
8			
9	2.20% Aug. 15, 2020 First Mortgage Bonds	300,000,000	3,072,956
10			552,000 D
11			
12	4.00% Aug. 15, 2045 First Mortgage Bonds	300,000,000	3,897,956
13			4,899,000 D
14			
15	3.60% May 15, 2046 First Mortgage Bonds	350,000,000	5,404,423
16			2,093,000 D
17	SUBTOTAL - ACCOUNT 221	5,000,000,000	90,323,115
18			
19	ACCOUNT 224		
20	OTHER LONG TERM DEBT		
21			
22	Right of Way debt		
23			
24	SUBTOTAL - ACCOUNT 224		
25			
26	Interest on Debt to Associated Companies		
27			
28			
29			
30			
31			
32			
33	TOTAL	5,000,000,000	90,323,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
8/13/2012	8/15/2022	8/13/2012	8/15/2022	300,000,000	6,450,000	5
						6
						7
7/7/1995	7/1/2025	7/7/1995	7/1/2025	250,000,000	17,812,500	8
						9
						10
3/17/1998	3/1/2028	3/17/1998	3/1/2028	150,000,000	9,750,000	11
						12
						13
7/21/2005	7/15/2035	7/21/2005	7/15/2035	250,000,000	13,125,000	14
						15
						16
5/25/2006	6/1/2036	5/25/2006	6/1/2036	400,000,000	24,455,459	17
						18
						19
6/26/2007	7/1/2037	6/26/2007	7/1/2037	350,000,000	21,700,000	20
						21
						22
11/17/2009	11/1/2039	11/17/2009	11/1/2039	300,000,000	16,156,992	23
						24
						25
8/11/2010	8/15/2040	8/11/2010	8/15/2040	250,000,000	12,125,000	26
						27
						28
8/13/2012	8/15/2042	8/13/2012	8/15/2042	500,000,000	18,496,479	29
						30
						31
5/20/2013	5/15/2023	5/20/2013	5/15/2023	400,000,000	10,400,000	32
				5,000,009,208	217,398,334	33

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
5/13/2014	5/15/2044	5/13/2014	5/15/2044	300,000,000	12,375,000	3
						4
						5
09/13/2017	09/15/2047	09/13/2017	09/15/2047	600,000,000	21,600,000	6
						7
						8
8/11/2015	8/15/2020	8/11/2015	8/15/2020	300,000,000	6,600,000	9
						10
						11
8/11/2015	8/15/2045	8/11/2015	8/15/2045	300,000,000	12,000,000	12
						13
						14
5/31/2016	5/15/2046	5/31/2016	5/15/2046	350,000,000	12,600,000	15
						16
				5,000,000,000	215,646,430	17
						18
						19
						20
						21
				9,208		22
						23
				9,208		24
						25
					1,751,904	26
						27
						28
						29
						30
						31
						32
				5,000,009,208	217,398,334	33

Schedule Page: 256 Line No.: 17 Column: i

Interest at stated rate	$25,000,000
Interest at swap gain	($544,540)
	$24,455,460

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

Interest at stated rate	$16,050,000
Interest at swap loss	$106,992
	$16,156,992

Schedule Page: 256 Line No.: 29 Column: i

Interest at stated rate	$17,000,000
Interest at swap loss	$1,496,479
	$18,496,479

Schedule Page: 256.1 Line No.: 22 Column: h

	Balance Dec. 31, 2017	Additions	Reductions	Balance Dec. 31, 2018
Right of Way debt	$ 35,044		$ (25,836)	$ 9,208

Schedule Page: 256.1 Line No.: 26 Column: i

Xcel Energy Services Inc	$1,389,990
NSP Nuclear Corp	$29,656
Money Pool	$332,258
	$1,751,904

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	492,335,131
2		
3		
4	Taxable Income Not Reported on Books	
5		61,452,077
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		1,163,287,235
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-175,897,386
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-1,747,184,438
21		
22	Equity in Earnings of Subsidiary Companies	77,812
23		
24	Total Income Tax Expense	27,201,622
25		
26		
27	Federal Tax Net Income	-178,727,947
28	Show Computation of Tax:	
29	Federal Income Tax at 21 percent	-37,532,869
30	Other	21,971,935
31	Total Federal Income Tax Payable	-15,560,934
32		
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44		

Schedule Page: 261 Line No.: 5 Column: b

TAXABLE INCOME NOT REPORTED ON BOOKS:	
Contributions in Aid of Construction	$61,452,077
	$61,452,077

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

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:	
Avoided Cost Interest	$15,073,814
Bad Debts	2,174,115
Book Amortization - Computer Software	58,478,920
Book Amortization - Other	16,510,731
Book Depreciation	601,450,049
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction	73,000
Book Rent Expense - Capitalized for Tax - Railcars	492,617
Book Unamortized Cost of Reacquired Debt	2,206,720
Capitalization of Software Expense - Books	647,620
Clearing Account Book Expense	16,429,238
Contributions Carryover	2,812,908
Deferred Compensation Plan Reserve	2,432,172
Deferred Fuel Costs	8,635,973
Employee Retention	100,723
Employee Stock Ownership Plan Dividends	1,818,388
Fuel Hedging	1,823
Interest Income/Expense on Disputed Tax	950,050
Litigation Reserve	202,500
Lobbying Expenses	1,875,000
Low Income Discount Program	161,842
Mark to Market Adjustment	2,541,941
Meals & Entertainment	727,000
Medical Deduction - Self Insured	380,583
Nonqualified Pension Plan	17,184
Nuclear Decommissioning	20,371,744
Nuclear Fuel Expense	121,888,518
Partnership Passthrough	15,500
Pension and Benefit Capitalized	9,960,513
Performance Recognition Awards	137,959
Prairie Island Extended Power Uprate Writedown Amortization	3,306,846
Prepaid Insurance	6,740,493
Public Utility Conservation Investments Programs Adjustment	15,523,537
Rate Refund	153,093,815
Regulatory Asset - Nuclear Refueling Outage Costs	18,818,064
Regulatory Asset/Liability - Transmission Attach O	2,498,908
Regulatory Asset/Liability - Transmission Cost Recovery Rider	31,623,247
Regulatory Asset/Liability - Windsource	3,100,374
Regulatory Asset - Property Tax	8,291,418
Regulatory Reserve - Environmental	9,087,314
Renewable Energy Standard/Credit	28,206
Section 174 - Section 59(e) Adjustment	21,711,180
Severance Accrual	68,219
South Dakota Infrastructure Tracker	315,622
Suite and Entertainment Tickets	424,000
Workers' Compensation	86,847
	$1,163,287,235

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

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

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:	
Allowance for Funds During Construction (AFDC) - Equity (Non-Conservation Improvement Program)	($26,899,218)
Deferred Revenue - Investment Tax Credit (ITC) Grant	(173,548)
Gain/(Loss) on Dispositions (Book)	(34,562)
Penalties	(28,844)
Insurance Fund Income (Cash Value)	(3,153,377)
Rate Surcharge	(134,908,371)
Solar Rewards Program	(10,699,466)
	($175,897,386)

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

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:	
Allowance for Funds During Construction (AFDC) - Debt (Non-Conservation Improvement Program)	($14,445,049)
Deferred Rent	(341,038)
Deferred Revenue	(493,054)
Electric Vehicle Charging Tariff	(237,355)
Employee Incentive Plans	(1,349,751)
Environmental Remediation	(12,658,123)
External Qualified Nuclear Decommissioning Fund	(20,371,744)
Federal Net Operating Loss	(770,185,344)
Gain/(Loss) on Dispositions (Tax)	(1,538,864)
Internally Developed Software	(571,289)
Interest Expense - Capital Leases	(195,444)
Inventory Reserve	(1,253,044)
Pension Expense	(37,034,748)
Performance Share Plan	(283,799)
Post Employment Benefits - Retiree Medical	(756,539)
Post Employment Benefits - Long Term Disability	(955,881)
Rate Case/Restructuring Expense	(646,578)
Regulatory Asset/Liability Cancellation	(43,913,201)
Regulatory Asset/Liability - Renewable Energy Standard (RES) Rider	(6,082,420)
Regulatory Asset - Gas Safety Deferrals	(306,727)
Regulatory Asset - Prairie Island Extended Power Uprate Cancellation	(4,008,572)
Repair Expenditures	(67,055,349)
Sale of Emission Allowances	(80,054)
Section 174	(31,800,000)
State Tax Deduction	(12,218,321)
Tax Amortization - Monticello Rerate	(6,295,644)
Tax Amortization - Computer Software	(57,216,453)
Tax Amortization - Pollution Control Facilities	(517,420)
Tax Depreciation	(525,520,402)
Tax Expense - Spent Fuel Isolation Devices	(79,313,401)
Tax Removal Cost Over Book	(48,997,810)
Vacation Accrual	(541,020)
	($1,747,184,438)

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

Northern States Power Company (a Minnesota corporation) is a member of an affiliated group which will file a consolidated federal income tax return for the year 2018. The other members of the affiliated group and the federal income tax provision of each are:

Xcel Energy Inc.	($85,716,992)
NSP Nuclear Corporation	(7,318)
United Power and Land Company	(46,354)
Northern States Power Company (Wisconsin) and Subsidiaries	7,902,487
Public Service Company of Colorado and Subsidiaries	80,987,999
Southwestern Public Service Company	12,787,728
Nicollet Holdings Company, LLC and Subsidiaries	930,173
Nicollet Projects Holdings Company, LLC and Subsidiaries	(1,416,427)
Xcel Energy Communications Group Inc. and Subsidiaries	(164,433)
Xcel Energy Markets Holdings Inc. and Subsidiaries	56,217
Xcel Energy International Inc.	25,228
Xcel Energy Retail Holdings Inc. and Subsidiaries	(606,576)
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(578,355)
Xcel Energy Ventures Inc. and Subsidiaries	(129,396)
Xcel Energy Venture Holdings, Inc. and Subsidiaries	(484,103)
Xcel Energy Wholesale Group Inc. and Subsidiaries	(44,469,021)
Xcel Energy WYCO Inc.	5,385,236
WestGas Interstate, Inc.	28,633
Xcel Energy Services Inc.	13,671,640

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL TAXES					
2	Income		76,263,290	-16,735,437	-101,104,389	-2,117,987
3	Income Tax Adjustment			1,174,503		-1,174,503
4						
5	FICA 2017	2,271,095			2,271,095	
6	FICA 2018			33,705,895	31,322,528	
7						
8	Unemployment 2017	9,550			9,550	
9	Unemployment 2018			195,023	191,365	
10						
11	SUBTOTAL	2,280,645	76,263,290	18,339,984	-67,309,851	-3,292,490
12						
13	STATE TAXES					
14	MINNESOTA					
15	Income		2,768,529	5,181,578	12,470,506	12,742,288
16	Income Tax Adjustment			279,854		-279,854
17						
18	Unemployment 2017	205,227			205,227	
19	Unemployment 2018			4,882,038	4,766,265	
20						
21	Property Taxes 2017	210,100,000		-374,547	209,725,453	
22	Property Taxes 2018			202,437,000		963,000
23	Property Tax MN Stlmt			10,885,938		-10,885,938
24						
25	Use	1,655,513		7,628,664	8,396,306	
26						
27	SUBTOTAL	211,960,740	2,768,529	230,920,525	235,563,757	2,539,496
28						
29	STATE TAXES					
30	NORTH DAKOTA					
31	Income		57,523	29,455	-233,494	-56,175
32	Income Tax Adjustment			889		-889
33						
34	Unemployment 2017	672			672	
35	Unemployment 2018			13,960	13,938	
36						
37	Property Tax 2017	6,345,000		275,138	6,620,138	
38	Property Tax 2018			5,478,000	15,703	
39						
40	Use	161,061		2,962,317	2,023,050	
41	TOTAL	225,009,647	79,089,342	264,099,578	182,478,583	-816,245

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2	SUBTOTAL	6,506,733	57,523	8,759,759	8,440,007	-57,064
3						
4	STATE TAXES					
5	SOUTH DAKOTA					
6	Unemployment 2017	-7,206			-7,206	
7	Unemployment 2018			52,744	52,846	
8						
9	Personal Property 2017	4,100,000		-32,662	4,067,338	
10	Personal Property 2018			4,440,000		
11	Personal Property FCA			-79,379	-79,379	
12						
13	Use 2018	153,596		1,030,925	1,083,687	
14						
15	SUBTOTAL	4,246,390		5,411,628	5,117,286	
16						
17	STATE TAXES					
18	KANSAS					
19	Personal Property 2018			689,942	689,942	
20						
21	SUBTOTAL			689,942	689,942	
22						
23	STATE TAXES					
24	WISCONSIN					
25	Income			-15,181	-18,691	-6,187
26						
27	Unemployment	-1,142		2,934	1,792	
28						
29	SUBTOTAL	-1,142		-12,247	-16,899	-6,187
30						
31	OTHER					
32	Georgia Unemployment 2017	-73		8	8	
33	Denver Occ'l Privilege	-12		12		
34	Prop Tax on Rail Car 2017	16,366		-14,968	1,398	
35	Prop Tax on Rail Car 2018			12,000		
36	Other			-7,065	-7,065	
37						
38						
39						
40						
41	TOTAL	225,009,647	79,089,342	264,099,578	182,478,583	-816,245

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
5,987,675		-15,380,893			-1,354,544	2
		1,174,503				3
						4
						5
2,383,367		28,119,024			5,586,871	6
						7
						8
3,658		173,251			21,772	9
						10
8,374,700		14,085,885			4,254,099	11
						12
						13
						14
2,684,831		7,102,703			-1,921,125	15
		277,997			1,857	16
						17
						18
115,773		3,118,305			1,763,733	19
						20
		-1,364,561			990,014	21
203,400,000		187,131,000			15,306,000	22
		10,885,938				23
						24
887,871		-350,339			7,979,003	25
						26
207,088,475		206,801,043			24,119,482	27
						28
						29
						30
149,251		752,618			-723,163	31
					889	32
						33
						34
22		8,544			5,416	35
						36
		558,122			-282,984	37
5,462,297		4,530,000			948,000	38
						39
1,100,328					2,962,317	40
226,727,805	2,750	231,091,014			33,008,564	41

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
6,711,898		5,849,284			2,910,475	2
						3
						4
						5
						6
-102		32,281			20,463	7
						8
		-32,662				9
4,440,000		4,440,000				10
		-79,379				11
						12
100,834					1,030,925	13
						14
4,540,732		4,360,240			1,051,388	15
						16
						17
						18
					689,942	19
						20
					689,942	21
						22
						23
						24
	2,677	-12,504			-2,677	25
						26
		1,796			1,138	27
						28
	2,677	-10,708			-1,539	29
						30
						31
	73	5			3	32
		14,829			-14,817	33
					-14,968	34
12,000					12,000	35
		-9,564			2,499	36
						37
						38
						39
						40
226,727,805	2,750	231,091,014			33,008,564	41

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

Federal income tax expense (Account No. 409.1 and 409.2) accrued for long term income tax receivable (Account No. 186)	$	771,659
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid-in-capital (Account No. 207)		(2,889,647)
Rounding		1
	$	(2,117,987)

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

Gas (Account No. 409.1)	$	3,963,225
Other income and deductions (Account No. 409.2)		(5,317,769)
	$	(1,354,544)

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

Federal income tax expense (Account No. 409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 242)	$	(2,613,335)
Federal income tax expense (Account No. 409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 253)		1,438,832
	$	(1,174,503)

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

Gas (Account No. 408.1)	$	2,481,309
Other income and deductions (Account No. 408.2)		98,328
Other		3,007,234
	$	5,586,871

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

Gas (Account No. 408.1)	$	15,391
Other income and deductions (Account No. 408.2)		594
Other		5,787
	$	21,772

Schedule Page: 262 Line No.: 15 Column: f

State income tax expense (Account No. 409.1 and 409.2) accrued for long term income tax receivable (Account No. 186)	$	(1,074,784)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid-in-capital (Account No. 207)		13,817,072
	$	12,742,288

Schedule Page: 262 Line No.: 15 Column: l

Gas (Account No. 409.1)	$	2,309,494
Other income and deductions (Account No. 409.2)		(4,230,619)
	$	(1,921,125)

Schedule Page: 262 Line No.: 16 Column: f

State income tax expense (Account No. 409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 242)	$	(406,413)
State income tax expense (Account No. 409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 253)		126,559
	$	(279,854)

Schedule Page: 262 Line No.: 16 Column: l

Other income and deductions (Account No. 409.2)	$	1,857

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

Gas (Account No. 408.1)	$ 265,847
Other income and deductions (Account No. 408.2)	11,989
Other	1,485,897
	$ 1,763,733

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

Gas (Account No. 408.1)	$ 990,014

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

Minnesota property tax on CWIP reclassified to a capital asset	$ 963,000

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

Gas (Account No. 408.1)	$ 15,240,000
Other income and deductions (Account No. 408.2)	66,000
	$ 15,306,000

Schedule Page: 262 Line No.: 23 Column: f

As part of the Minnesota 2016 Multi-Year Electric Rate Case (Docket E-002/GR-15-826) the MPUC approved a symmetrical true-up of actual property taxes for the years 2017-2019 to a baseline amount. Adjustment represents deferral of amount above/below baseline.

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

Gas (Account No. 408.1)	$ (28,702)
Other	8,007,705
	$ 7,979,003

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

State income tax expense (Account No. 409.1 and 409.2) accrued for long term income tax receivable (Account No. 186)	$ (5,511)
Annual allocation of unitary benefit/detriment for state income taxes accrued as additional paid-in-capital (Account No. 207)	(50,663)
Rounding	(1)
	$ (56,175)

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

Gas (Account No. 409.1)	$ 99,001
Other income and deductions (Account No. 409.2)	(822,164)
	$ (723,163)

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

State income tax expense (Account No. 409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 242)	$ (890)
State income tax expense (Account No. 409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 253)	1
	$ (889)

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

Other income and deductions (Account No. 409.2)	$ 889

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

Gas (Account No. 408.1)	$ 723
Other income and deductions (Account No. 408.2)	34
Other	4,659
	$ 5,416

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

Gas (Account No. 408.1)	$	(282,984)

Schedule Page: 262 Line No.: 38 Column: l

Gas (Account No. 408.1)	$	948,000

Schedule Page: 262.1 Line No.: 7 Column: l

Gas (Account No. 408.1)	$	2,734
Other income and deductions (Account No. 408.2)		126
Other		17,603
	$	20,463

Schedule Page: 262.1 Line No.: 11 Column: a

South Dakota Personal Property Tax collected through the Fuel Clause Adjustment. See page 232.

Schedule Page: 262.1 Line No.: 19 Column: l

Gas (Account No. 408.1)	$	689,942

Schedule Page: 262.1 Line No.: 25 Column: f

Annual allocation of unitary benefit/detriment for Wisconsin income tax accrued as additional paid-in-capital (Account No. 207)	$	(6,187)

Schedule Page: 262.1 Line No.: 25 Column: l

Other income and deductions (Account No. 409.2)	$	(2,677)

Schedule Page: 262.1 Line No.: 27 Column: l

Gas (Account No. 408.1)	$	152
Other income and deductions (Account No. 408.2)		7
Other		979
	$	1,138

Schedule Page: 262.1 Line No.: 33 Column: l

Gas (Account No. 408.1)	$	1,453
Other income and deductions (Account No. 408.2)		35
Other		(16,305)
	$	(14,817)

Schedule Page: 262.1 Line No.: 34 Column: a

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

Schedule Page: 262.1 Line No.: 35 Column: a

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

Schedule Page: 262.1 Line No.: 36 Column: l

Gas (Account No. 408.1)	$	2,499

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%	57,094			411.4	4,718	1
4	7%						
5	10%	19,490,667			411.4	1,208,091	
6	30%	1,576,455			411.4	97,312	-1
7							
8	TOTAL	21,124,216				1,310,121	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	1,614			411.4	63	
13	10%	1,296,839			411.4	106,762	
14	Total	1,298,453				106,825	
15	Common Utility						
16	4%	5,268			411.4	776	-1
17	10%	99,667			411.4	6,565	1
18	Total	104,935				7,341	
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48	Utility & Non-Utili	22,527,604				1,424,287	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
52,377	56 Years		3
			4
18,282,576	52 Years		5
1,479,142	21 Years		6
			7
19,814,095			8
			9
			10
			11
1,551	68 Years		12
1,190,077	49 Years		13
1,191,628			14
			15
4,491	50 Years		16
93,103	50 Years		17
97,594			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
21,103,317			48

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

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

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

(a) Common Allocation

Electric - 92.43%	$ 90,208
Gas - 7.57%	7,386
	$ 97,594

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OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Unfunded Nonqualified Pension	5,395,111	232	1,148,000	503,304	4,750,415
2	Benefit Costs					
3						
4	Deferred Compensation					
5	Employees	10,364,839	Various	676,698	3,481,832	13,169,973
6	Employees (Wealth Op)	5,367,194	232	533,328	160,364	4,994,230
7						
8	Postemployment Benefit-Injury	16,317,350	Various	2,122,198	1,166,317	15,361,469
9	Compensation					
10						
11	Environmental & Regulatory	3,463,064	242	1,233,674		2,229,390
12	Reserves					
13						
14	Nuclear Waste Strategy Coalition	84,902	232	62,834	86,422	108,490
15						
16	Renewable Development Fund	45,788,597	232	38,429,417	31,800,000	39,159,180
17	Obligations					
18						
19	Long-Term Income Tax & Interest	7,069,553	Various	2,896,124	25,973	4,199,402
20	Payable					
21						
22	Deposits-Landfill Power	296,311	131	296,576	265	
23						
24	Customer Prepayments	548,626	107	5,057,327	6,894,351	2,385,650
25						
26	Deferred Revenue	2,448,981	Various	510,750	17,696	1,955,927
27						
28	Wholesale Merger Settlement	82,703				82,703
29						
30	Pre-Funded AFUDC					
31	Metro Emissions Reduction Rider	56,818,893	405	2,236,179		54,582,714
32	Mercury Emission Reduction Rider	487,882	405	55,577		432,305
33	Minnesota Transmission Cost	30,892,869	Various	567,665		30,325,204
34	Recovery Rider					
35	FERC Transmission	39,801,478	Various	758,334		39,043,144
36	Renewable Energy Standards Rider	26,718,170	405	1,421,051	3,728,080	29,025,199
37	South Dakota Transmission	1,844,172	Various	29,845	78,101	1,892,428
38	Cost Recovery Rider					
39	North Dakota Transmission	1,213,762	Various	84,497	261,922	1,391,187
40	Cost Recovery Rider					
41						
42	Executive PSP - Long Term	2,056,398	Various	1,397,814	928,644	1,587,228
43						
44	Deferred Revenue-ITC Grant	1,804,767	405	173,548		1,631,219
45						
46	Mark-to-Market Adjustment	10,511,356	456	1,734,636	550,564	9,327,284
47	TOTAL	325,443,020		85,241,376	145,634,272	385,835,916

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OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Mankato/Cannon Falls Lease	39,342,558				39,342,558
2	Normalization					
3						
4	Long-Term Payroll Tax Liability	1,640,320				1,640,320
5						
6	Coal Car Residual Value Deficit	2,226,172			660,323	2,886,495
7						
8	Sherco Unit 3 Insurance Settlement	825,659	107	825,659		
9						
10	401 Nicollet Lease Credit	12,031,333	Various	4,682,210	4,348,447	11,697,570
11						
12	Laurentian Biomass PPA		182.3	18,083,333	90,416,667	72,333,334
13	Termination					
14						
15	Pine Bend Biomass PPA		182.3	224,102	525,000	300,898
16	Termination					
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	** Footnote from page 106b					
43						
44						
45						
46						
47	TOTAL	325,443,020		85,241,376	145,634,272	385,835,916

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

Accounts charged:

131	$516,823
921	159,875
Total	$676,698

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

Accounts charged:

131	$1,291,593
232	688,828
234	141,777
Total	$2,122,198

Schedule Page: 269 Line No.: 19 Column: c

Accounts charged:

143	$100,742
232	442,082
242	1,565,392
419	138,559
421	649,349
Total	$2,896,124

Schedule Page: 269 Line No.: 26 Column: c

Accounts charged:

447	$37,500
456	300,000
495	173,250
Total	$510,750

Schedule Page: 269 Line No.: 33 Column: c

405	$564,032
419.1	$2,755
432	$878
Total	$567,665

Schedule Page: 269 Line No.: 35 Column: c

405	$706,822
419.1	39,063
432	12,449
Total	$758,334

Schedule Page: 269 Line No.: 35 Column: d

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized amortization expense (405) amount is $56,576

Schedule Page: 269 Line No.: 35 Column: e

The amount reported for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midcontinent ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company unjurisdictionalized Pre-funded AFUDC (Total Accounts Other Expenses - 432, Other Revenue - 419.1) amount is $1,992,137

Schedule Page: 269 Line No.: 37 Column: c

405	$29,551
419.1	$227
432	$67
Total	$29,845

Schedule Page: 269 Line No.: 39 Column: c

405	$19,969
419.1	43,652
432	20,876
Total	$84,497

Schedule Page: 269 Line No.: 42 Column: c

Accounts charged:

232	$935,580
253	462,234
Total	$1,397,814

Schedule Page: 269.1 Line No.: 10 Column: c

Accounts charged:

165	$477,642
233	4,204,568
Total	$4,682,210

Schedule Page: 269.1 Line No.: 42 Column: a

The Form 1 reports the other deferred credits balances at the beginning of year and at the end of the year. Included in this account is the credit for pre-funded AFUDC on CWIP related to the specific transmission projects that are included in the formula. These are jurisdictional amounts. The net pre-funded AFUDC amount used in the Attachment O formula is a total NSP system number (unjurisdictionalized). The formula requires the Company to use a 13 month average balance in the determination of the adjustment to rate base related to this account.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	30,841,977	-1,946,676	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	30,841,977	-1,946,676	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	30,841,977	-1,946,676	
18	Classification of TOTAL			
19	Federal Income Tax	23,998,338	-1,522,453	
20	State Income Tax	6,843,639	-424,223	
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						28,895,301	4
							5
							6
							7
						28,895,301	8
							9
							10
							11
							12
							13
							14
							15
							16
						28,895,301	17
							18
						22,475,885	19
						6,419,416	20
							21

NOTES (Continued)

Schedule Page: 272 Line No.: 8 Column: k

All amounts in columns b - k are related to Electric Steam Production Plant.

Accumulated Deferred Income Taxes (Account No. 281). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income tax balances in the formula.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,991,153,450	18,077,861	
3	Gas	121,598,227	2,541,966	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,112,751,677	20,619,827	
6	Non-Operating	-27,454		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,112,724,223	20,619,827	
10	Classification of TOTAL			
11	Federal Income Tax	1,491,609,657	-19,885,579	
12	State Income Tax	621,114,566	40,505,406	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
			-48,914,724		-42,613,352	2,015,532,683	2
			-2,280,994			126,421,187	3
							4
			-51,195,718		-42,613,352	2,141,953,870	5
808,812						781,358	6
							7
							8
808,812			-51,195,718		-42,613,352	2,142,735,228	9
							10
544,534			-44,403,965		-27,748,475	1,488,924,102	11
264,278			-6,791,753		-14,864,877	653,811,126	12
							13

NOTES (Continued)

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

The amortization of Excess ADIT included above in 410.1 is $48,449,164.

	2018 Average Rate Assumption Method
Decommissioning	-
Electric Distribution Plant	8,482,257
Electric General Plant	2,707,179
Electric Intangible Plant	825,913
Electric Nuclear Fuel	7,332,320
Electric Production Plant	22,423,727
Electric Transmission Plant	4,079,590
Electric Transmission-Production Plant	36,194
Common (Allocation to Electric)	2,571,359
	48,458,539
Non Utility	(9,375)
Total Electric	$ 48,449,164

Common allocation for financial reporting may be different than for rate making.

Common (Unallocated)	2,800,435

The Flowback of permanent items included above in 410.1 is $7,879,985 for Electric only.

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

182.3, 254 & 281

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

182.3, 254 & 282

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

Electric - Plant Related:	**Dec. 31, 2017**	**410.1 & Adjustments**	**Dec. 31, 2018**
Electric Distribution Plant	814,508,776	6,804,282	821,313,058
Electric General Plant	85,117,304	(1,270,182)	83,847,122
Electric Intangible Plant	8,536,957	(777,593)	7,759,364
Electric Nuclear Fuel	58,868,724	(16,666,389)	42,202,335
Electric Nuclear Production Plant	607,477,325	15,365,305	622,842,630
Electric Production Plant	777,377,459	(14,168,472)	763,208,987
Electric Transmission Plant	807,154,549	29,152,843	836,307,392
Electric Transmission-Production Plant	15,500,930	184,383	15,685,313
Common (Allocation to Electric)	25,749,598	(546,315)	25,203,283
Regulatory Differences - Prior Flow Thru / Rate Change	(1,477,893,845)	48,878,608	(1,429,015,237)
Regulatory Differences - AFUDC Equity	114,952,847	(1,600,512)	113,352,335
Decommissioninig Qualified	153,802,826	(40,976,725)	112,826,101
Total Electric Plant Related Only	**1,991,153,450**	**24,379,233**	**2,015,532,683**

Accumulated Deferred Income Taxes (Account No. 282). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to regulatory differences related to income taxes.

The Excess ADIT above in column c include the ungrossed amounts presented below. These amounts will be amortized over the book lives of the underlying assets.

Excess (Electric only)	12/31/2018 Excess	12/31/2018 Gross up	12/31/2018 Total Regulatory
Flow Through	(3,025,265)	(1,184,350)	(4,209,615)
Method Life (Protected)	(826,002,526)	(323,368,698)	(1,149,371,224)
Other Basis Differences (Unprotected)	(197,942,583)	(77,491,815)	(275,434,398)
	(1,026,970,374)	(402,044,863)	(1,429,015,237)

Includes Non-Utility and Common Allocated. The common allocation for the financial reporting is different from the allocation used in rate making.

Non-utility			
Flow Through	(99,900)	(39,109)	(139,009)
Method Life (Protected)	11,928	4,670	16,598
Other Basis Differences (Unprotected)	3,456	1,353	4,809
Non Utility Total:	(84,516)	(33,086)	(117,602)
Common (allocated)			
Flow Through	(25,800)	(10,100)	(35,900)
Method Life (Protected)	19,333,861	7,568,942	26,902,803
Other Basis Differences (Unprotected)	1,843,724	721,793	2,565,517
Common (allocated) Total:	21,151,785	8,280,635	29,432,420
Common (unallocated)			
Flow Through	(30,814)	(12,063)	(42,877)
Method Life (Protected)	23,091,480	9,039,999	32,131,479
Other Basis Differences (Unprotected)	2,202,060	862,076	3,064,136
Common (unallocated) Total:	25,262,726	9,890,012	35,152,738

Schedule Page: 274 Line No.: 3 Column: g

182.3, 254 & 282

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric - Plant	50,837,182	4,678,724	
4	Electric - Non-Plant	161,950,329	89,343,687	60,288,411
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	212,787,511	94,022,411	60,288,411
10	Gas			
11	Gas	35,050,513	7,834,470	12,419,768
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	35,050,513	7,834,470	12,419,768
18	Non Operating	-731,006		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	247,107,018	101,856,881	72,708,179
20	Classification of TOTAL			
21	Federal Income Tax	179,250,923	68,023,830	56,866,338
22	State Income Tax	67,856,095	33,833,051	15,841,841
23	Local Income Tax			

NOTES

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		182.3	33,299		19,161	55,501,768	3
		254	9,556,605	254	28,917,280	210,366,280	4
							5
							6
							7
							8
			9,589,904		28,936,441	265,868,048	9
							10
		254	1,731,365	254	2,645,176	31,379,026	11
							12
							13
							14
							15
							16
			1,731,365		2,645,176	31,379,026	17
-79	513	219.1	80,668			-812,266	18
-79	513		11,401,937		31,581,617	296,434,808	19
							20
-80	348		10,346,249		28,676,477	208,738,215	21
1	165		1,055,688		2,905,140	87,696,593	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: i

182.3 & 283

Schedule Page: 276 Line No.: 3 Column: k

Electric - Plant-Related:	Dec. 31, 2017	410.1 & Adjustments	Dec. 31, 2018
Electric Distribution Plant	$177,012	($15,099)	$161,913
Electric General Plant	742,470	26,577	769,047
Electric Intangible Plant	5,733,237	(805,579)	4,927,658
Electric Nuclear Production Plant	4,195,902	(682,155)	3,513,747
Electric Production Plant	34,252	(39,083)	(4,831)
Electric Transmission Plant	55,616	(1,436)	54,180
Common (Allocation to Electric)	38,533,047	6,195,499	44,728,546
Regulatory Differences - AFUDC Equity	1,365,646	(14,138)	1,351,508
Total Electric - Plant-Related	$50,837,182	$4,664,586	$55,501,768

Accumulated Deferred Income Taxes (Account No. 283). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to regulatory differences related to income taxes. An adjustment is made to include the regulatory liability balance related to nonplant accumulated deferred income tax rate change.

Schedule Page: 276 Line No.: 19 Column: k

Refer to FERC page 278 for NSPM's regulatory liability related to nonplant excess ADIT.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	ITC Gross-up to Pre-Tax Rate Levels	9,512,682	190	612,202		8,900,480
2						
3	Deferred Tax Collected in Rates in Excess	1,460,200,283	282	46,412,172		1,413,788,111
4	of Current Tax Accrual Levels					
5						
6	Unrealized Gains on Decommissioning Trust	398,649,859	Various	106,209,783		292,440,076
7						
8	Gain from Sales of Emission Allowances	59	411.8	8	59	110
9						
10	Electric Low Income Discount Program		Various	14,716,864	18,379,321	3,662,457
11	and PowerON Program					
12	- MN Electric E-002/GR-15-826					
13	- MN Electric E-002/M-04-1956					
14	- MN Electric E-002/M-17-629					
15						
16	Gas Low Income Discount Program	658,482	Various	2,327,710	3,003,348	1,334,120
17	- MN Gas G-002/GR-06-1429					
18						
19	Pre-ARO Decommissioning	1,564,395,011	282	33,619,950	92,232,966	1,623,008,027
20						
21	Derivatives & Hedging - Retail Electric & Gas	17,156,648	175	6,780,463		10,376,185
22						
23	Minnesota Deferred Electric Commodity Costs		Various	800,995,825	805,943,938	4,948,113
24	- MN Docket E-002/M-14-364					
25						
26	South Dakota Deferred Electric Commodity Costs	1,128,938	557	47,140,036	51,842,509	5,831,411
27	- SD Docket EL14-058					
28						
29	North Dakota Deferred Electric Commodity Costs	2,473,291	557	52,915,050	52,856,218	2,414,459
30	- ND Docket PU-12-813					
31						
32	Power Purchase Agreement	847,863	Various	65,521	53,373	835,715
33						
34	South Dakota Transmission Cost Recovery Rider	1,052,065	407.3	6,571,902	6,886,166	1,366,329
35	- SD Docket EL17-036					
36						
37	South Dakota Property Tax				111,296	111,296
38						
39	North Dakota Transmission Cost Recovery				1,403,761	1,403,761
40	-ND Docket PU-17-365					
41	TOTAL	3,578,757,196		1,264,412,842	1,358,543,637	3,672,887,991

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Department of Energy Settlement Payment	11,205,059	142	11,843,318	12,005,781	11,367,522
2	- MN Docket E-002/M-15-1089					
3	- MN Docket E-002/M-17-828					
4						
5	Minnesota Retail Asset Margin Sharing	4,163,417	557	24,915,752	26,735,740	5,983,405
6	- MN Docket E-002/GR-12-961					
7						
8	North Dakota Retail Asset and Non-Asset	1,545,697	557	2,777,105	3,396,016	2,164,608
9	Margin Sharing					
10	- ND Docket PU-10-657					
11						
12	South Dakota Retail Asset and Non-Asset	1,020,446	557	2,466,091	2,139,375	693,730
13	Margin Sharing					
14	- SD Docket EL12-046					
15						
16	South Dakota Production Tax Credit Sharing	1,372,544	557	5,290,212	4,704,056	786,388
17	- SD Docket EL11-019					
18						
19	Minnesota Service Quality Program	663,225	142	487,300	437,075	613,000
20	- MN Docket E-002/M-16-281					
21	- MN Docket E-002/M-16-382					
22						
23	North Dakota Service Quality Program		142	31,550	131,550	100,000
24	- ND Docket PU-11-557					
25	- ND Docket PU-12-813					
26						
27	South Dakota Fuel Clause Adjustment Charge		431	7,607	10,455	2,848
28	- SD EL14-058					
29						
30	Transmission Formula Rates	11,330,112	Various	10,386,023	10,861,075	11,805,164
31						
32	North Dakota ITC	5,907,723			1,674,717	7,582,440
33						
34	South Dakota Infrastructure	1,029,439	407.3	11,048,581	11,364,202	1,345,060
35	- SD Docket EL17-039					
36						
37	Minnesota Revenue Decoupling 2018	868,342	407.3	868,342	13,016,954	13,016,954
38	- MN Docket E-002/GR-15-826					
39						
40						
41	TOTAL	3,578,757,196		1,264,412,842	1,358,543,637	3,672,887,991

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	North Dakota Renewable Energy Rider	881,879	407.4	1,511,950	641,845	11,774
2	- ND Docket PU-17-364					
3						
4	Minnesota Transmission Cost Recovery Rider				5,252,640	5,252,640
5	- MN Docket E-002/GR-17-797					
6						
7	Transco Administrative Services	160,213	407.4	80,107		80,106
8	Agreement					
9	- MN Docket E002/AI-14-759					
10	- MN Docket E002/AI-15-826					
11	- Amortized over four years (01/2016-12/2019)					
12						
13	Windsource	695,635	Various	5,477,096	6,686,781	1,905,320
14	- MN Docket E-002/M-01-1479					
15	- MN Docket E-002/GR-13-868					
16						
17	2017-2018 Minnesota Deferred Property Tax	5,561,793	142	7,370,863	11,442,254	9,633,184
18	- MN Docket E-002/GR-15-826					
19						
20	Conservation and Energy Management Program Costs	920,899	232	19,310,621	23,648,630	5,258,908
21	Minnesota Natural Gas					
22	- MN Docket G-002/M-18-240					
23	- Generally amortized over 12 month					
24	period following the expenditure					
25						
26	Minnesota Renewable Energy Standard	14,376,790	407.4	17,601,232	11,507,038	8,282,596
27	- MN Docket G-002/M-17-818					
28						
29	Nonplant Excess ADIT	55,904,209	190	4,615,761		51,288,448
30						
31	Renewable Development Fund Rider	5,074,593	407.3	4,535,889		538,704
32	- MN Docket E-002/M-17-712					
33						
34	2017 Tax Cuts and Jobs Act - MN Electric				132,964,558	132,964,558
35	- MN Docket E,G999/CI-17-895					
36						
37	2017 Tax Cuts and Jobs Act - MN Gas				5,626,525	5,626,525
38	- MN Docket E,G999/CI-17-895					
39						
40	2017 Tax Cuts and Jobs Act - ND Electric				9,816,697	9,816,697
41	TOTAL	3,578,757,196		1,264,412,842	1,358,543,637	3,672,887,991

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	- ND Docket PU-18-155					
2						
3	2017 Tax Cuts and Jobs Act - ND Gas		456	1,080,990	1,080,990	
4	- ND Docket PU-18-156					
5						
6	2017 Tax Cuts and Jobs Act - SD Electric		456	10,868,150	10,868,150	
7	- SD Docket GE17-003					
8						
9	Inver Hills Gain Sharing		456	2,182,053	2,310,053	128,000
10	- MN Docket E-002/M-17-529					
11	- ND Docket PU-18-200					
12						
13	Refund Liability				10,974,000	10,974,000
14						
15	Sherco Land Sale		456	1,288,763	1,275,903	-12,860
16	- MN Docket E-002/M-17-528					
17						
18	Minnesota Incentive Compensation Refund				5,257,622	5,257,622
19	- MN Docket E-002/M-18-121					
20						
21						
22						
23						
24						
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27						
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36						
37						
38						
39						
40						
41	TOTAL	3,578,757,196		1,264,412,842	1,358,543,637	3,672,887,991

Schedule Page: 278 Line No.: 6 Column: c

Accounts charged:

128	$68,233,058
282	40,976,725
Total	$109,209,783

Schedule Page: 278 Line No.: 10 Column: c

Accounts charged:

142	$13,627,520
182.3	161,842
232	498,064
431	429,438
Total	$14,716,864

Schedule Page: 278 Line No.: 16 Column: c

Accounts charged:

142	$2,224,152
232	103,558
Total	$2,327,710

Schedule Page: 278 Line No.: 23 Column: c

Accounts charged:

182.3	$4,559,386
557	796,436,439
Total	$800,995,825

Schedule Page: 278 Line No.: 32 Column: c

Accounts charged:

186	$17,540
555	47,981
Total	$65,521

Schedule Page: 278.1 Line No.: 30 Column: c

Accounts charged:

456.1	$10,150,778
565	235,245
Total	$10,386,023

Schedule Page: 278.2 Line No.: 13 Column: c

Accounts charged:

555	$5,441,373
921	35,723
Total	$5,477,096

Schedule Page: 278.2 Line No.: 29 Column: f

	Excess Nonplant ADIT – Regulatory Liability*	Gross-Up	Total
Electric	$ 35,100,967	$ 13,741,549	$ 48,842,516
Gas	1,757,784	688,148	2,445,932
Total	$ 36,858,751	$ 14,429,697	$ 51,288,448

*For purposes of calculating the the NSP Companies transmission formula rate, the excess non-plant balances (excluding tax gross-up) are as follows. The Company uses the average of the beginning of the year and the end of the year balances in the formula. These balances are being flowed back to customers over various periods consistent with the nature of the item.

	Excess Balance 12/31/2017	Amortization 2018	Excess Balance 12/31/2018
Book Unamortized Cost of Reaquired Debt	$ 2,380,686	$ (476,137)	$ 1,904,549
Deferred Fuel Costs	580,670	(116,134)	464,536
Electric Vehicle Charging Tariff	23,178	(4,636)	18,542
Employee Retention	13,153	(2,631)	10,522
Interest Income/Expense on Disputed Tax	233,586	(46,717)	186,869
Low Income Discount Program	20,612	(4,122)	16,490
Mark to Market Adjustment	1,313,598	(262,720)	1,050,878
Nuclear Refueling	8,785,734	(1,757,147)	7,028,587
Partnership Passthrough	158,948	(31,790)	127,158
Pension Expense	22,665,162	(1,511,011)	21,154,151
Prepaid Insurance	2,539,988	(507,998)	2,031,990
Property Tax - LT Total	2,083,592	(416,718)	1,666,874
Public Utility Conservation Investment Programs	8,117,822	(1,623,564)	6,494,258
Rate Case / Restructuring Expense	465,789	(93,158)	372,631
Rate Surcharge	6,428,005	(1,285,601)	5,142,404
Renewable Energy Standard/Credit	3,592	(718)	2,874
Transmission Attachment O	210,490	(42,098)	168,392
State Tax Deduction Cash vs Accrual	526,587	(105,317)	421,270
Windsource	30,823	(6,165)	24,658
Total Electric	$ 56,582,015	$ (8,294,382)	$ 48,287,633

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,432,937,548	1,311,929,131
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,575,574,856	1,524,374,438
5	Large (or Ind.) (See Instr. 4)	716,179,408	690,162,808
6	(444) Public Street and Highway Lighting	27,408,740	25,538,287
7	(445) Other Sales to Public Authorities	10,001,817	9,609,774
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	692,309	657,561
10	TOTAL Sales to Ultimate Consumers	3,762,794,678	3,562,271,999
11	(447) Sales for Resale	165,135,625	95,341,471
12	TOTAL Sales of Electricity	3,927,930,303	3,657,613,470
13	(Less) (449.1) Provision for Rate Refunds	-2,879,310	-22,224,485
14	TOTAL Revenues Net of Prov. for Refunds	3,930,809,613	3,679,837,955
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,029,827	6,200,682
17	(451) Miscellaneous Service Revenues	2,810,894	3,090,294
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,055,666	4,878,366
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	264,370,862	501,564,990
22	(456.1) Revenues from Transmission of Electricity of Others	285,383,048	234,505,456
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	564,650,297	750,239,788
27	TOTAL Electric Operating Revenues	4,495,459,910	4,430,077,743

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
10,476,336	9,899,976	1,313,099	1,302,327	2
				3
15,323,211	15,104,083	156,937	155,985	4
8,877,106	8,829,073	552	551	5
141,480	144,914	5,727	5,300	6
82,951	80,228	2,227	2,235	7
				8
6,987	7,393			9
34,908,071	34,065,667	1,478,542	1,466,398	10
7,656,805	6,654,822			11
42,564,876	40,720,489	1,478,542	1,466,398	12
				13
42,564,876	40,720,489	1,478,542	1,466,398	14

Line 12, column (b) includes $ -239,832 of unbilled revenues.
Line 12, column (d) includes -7,013,117 MWH relating to unbilled revenues

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

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

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

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

Schedule Page: 300 Line No.: 13 Column: b

Credit balance due to accrual reversal.

Schedule Page: 300 Line No.: 13 Column: c

Credit balance results from differences between final and interim rates in Minnesota electric rate case docket 15-826.

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

Connection charges	$ 2,465,210
NSF Check Fees	334,616
Other, less than $250,000 each	11,068
	$ 2,810,894

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

Connection charges	$ 2,694,380
NSF Check Fees	323,873
Other, less than $250,000 each	72,041
	$ 3,090,294

Schedule Page: 300 Line No.: 19 Column: b

Rent from Electric Property (Account No. 454). The rent revenue credit from electric property included in the formula is income directly related to transmission facilities, such as pole attachments, rentals and special use.

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

Includes reimbursement from NSP-Wisconsin for production costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

Fixed Production Expense	$220,810,971
Variable Production Expense	190,423,065
Total Interchange Agreement	$411,234,036

Also includes the following items:

Fees charged to burn Refuse Derived Fuel	$ 7,580,389
Renewable*Connect	5,753,180
Windsource Program	5,477,420
EEI Mutual Aid Revenue	4,895,394
Inver Hills Gain Sharing	3,415,636
Net distribution of commodity trading margins under Joint Operating Agreement	2,459,720
Purchased Power Reimbursement	742,332
Distribution Facility Fixed Charges	720,207
Work on Customers' Equipment	458,723
Facilities Agreement	439,379
Manitoba Hydro Energy Service Agreement	300,000
Solar Gardens-Subscribed	96,300
Timber Sales	73,234
Service Quality Plans	(684,913)
North Dakota Earnings Sharing	(2,983,461)

Change in net over-recovered electric commodity costs	(12,533,597)
Conservation Improvement Program incentive, net of accruals and recoveries	(19,297,301)
Customer refunds due to 2017 Tax Cuts and Jobs Act	(144,428,431)
Other, less than $250,000 each	652,615
	$264,370,862

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

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the FERC-approved Interchange Agreement between the companies restated Jan. 16, 2001.

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Fixed Production Expenses	$237,479,540
Variable Production Expenses	187,264,280
Transmission Expenses	65,477,314
Total Interchange Agreement	$490,221,134

Also includes the following items:

Change in net over-recovered electric commodity costs	$ 7,719,681
Fees charged to burn Refuse Derived Fuel	5,860,140
Windsource Program	5,841,446
Renewable*Connect	2,092,013
EEI Mutual Aid Revenue	1,292,525
Work on Customers' Equipment	1,099,113
Distribution Facility Fixed Charges	721,632
Fuel Refund	560,038
Purchased Power Reimbursement	478,071
Facilities Agreement	473,763
Manitoba Hydro Energy Service Agreement	300,000
Service Quality Plans	(530,740)
Net distribution of commodity trading margins under Joint Operating Agreement	(4,367,776)
Conservation Improvement Program incentive, net of accruals and recoveries	(10,563,326)
Other, less than $250,000 each	367,276
	$501,564,990

Schedule Page: 300 Line No.: 22 Column: b

Includes $62,491,776 reimbursement from NSP-Wisconsin for transmission costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL					
2	Minnesota					
3	A00 Water Heating	178	23,274	40	4,450	0.1308
4	A01 Residential	5,075,334	723,288,978	757,259	6,702	0.1425
5	A02 Residential Time of Day	3,987	495,580	323	12,344	0.1243
6	A03 Residential Underground	3,823,314	534,157,042	388,570	9,839	0.1397
7	A04 Residential TOD Undergnd	4,319	548,158	294	14,690	0.1269
8	A05 Energy Control	40,668	3,522,371	3,100	13,119	0.0866
9	A06 Limited Off Peak	2,992	271,078	371	8,065	0.0906
10	A07 Auto Protective Lighting	6,448	1,126,295			0.1747
11	A08 Residential Vehicle Tariff	1,088	106,608			0.0980
12	Unbilled	-52,736	-3,679,956			0.0698
13	North Dakota					
14	D01 Residential	625,220	66,008,200	68,199	9,168	0.1056
15	D02 Residential Time of Day	830	74,028	29	28,621	0.0892
16	D03 Residential Underground	171,019	16,961,117	12,362	13,834	0.0992
17	D04 Residential TOD Undergrnd	117	10,343	6	19,500	0.0884
18	D05 Energy Control	4,169	302,595	296	14,084	0.0726
19	D10 Limited Off Peak	837	52,170	106	7,896	0.0623
20	D11 Auto Protective Lighting	336	55,341			0.1647
21	Unbilled	-8,204	-859,412			0.1048
22	South Dakota					
23	E01 Residential	342,756	40,549,743	44,571	7,690	0.1183
24	E02 Residential Time of Day	42	3,947	4	10,500	0.0940
25	E03 Residential Underground	434,071	50,087,391	37,360	11,619	0.1154
26	E04 Residential Time of Day	49	5,217	3	16,333	0.1065
27	E06 Residential Heat Pump	1,863	153,736	102	18,265	0.0825
28	E10 Energy Control	1,326	94,295	103	12,874	0.0711
29	E11 Limited Off Peak	14	854	1	14,000	0.0610
30	E12 Auto Protective Lighting	342	61,826			0.1808
31	Unbilled	-4,043	-483,271			0.1195
32	Total Residential	10,476,336	1,432,937,548	1,313,099	7,978	0.1368
33						
34	COMMERCIAL AND INDUSTRIAL					
35	Minnesota					
36	A05 Energy Control	2,077	171,065	104	19,971	0.0824
37	A06 Limited Off Peak	1,986	202,837	87	22,828	0.1021
38	A07 Auto Protective Lighting	24,297	3,670,789			0.1511
39	A09 Small General Service	24	12,483	99	242	0.5201
40	A10 Small General Service	798,233	103,043,754	74,097	10,773	0.1291
41	TOTAL Billed	35,077,184	3,771,652,917	1,478,542	23,724	0.1075
42	Total Unbilled Rev.(See Instr. 6)	-169,113	-8,858,239	0	0	0.0524
43	TOTAL	34,908,071	3,762,794,678	1,478,542	23,610	0.1078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	A11 Water Heating	216	25,742	79	2,734	0.1192
2	A12 Small General TOD Service	40,947	4,766,935	2,869	14,272	0.1164
3	A13 Direct Current	2	9,706	3	667	4.8530
4	A14 General Service	8,199,846	880,769,833	41,167	199,185	0.1074
5	A15 General TOD Service	8,165,218	693,592,927	4,601	1,774,662	0.0849
6	A16 Small General kWh metered	15,342	2,028,805	3,004	5,107	0.1322
7	A18 Small General TOD Service	27,364	3,391,883	4,332	6,317	0.1240
8	A22 Small Gen TOD Low Watt	2,353	319,709	735	3,201	0.1359
9	A23 Peak Control Tiered	1,146,060	117,196,525	1,403	816,864	0.1023
10	A24 Peak Control Time of Day	2,536,597	203,866,033	347	7,310,078	0.0804
11	A27 Tier 1 Energy Control	442,240	29,310,020	14	31,588,571	0.0663
12	A29 Hiawatha Light Rail	25,841	2,427,153	16	1,615,063	0.0939
13	A62 Firm Real Time Pricing	11,026	1,001,987	2	5,513,000	0.0909
14	A63 Experimental Real Time	5,213	398,796	1	5,213,000	0.0765
15	Unbilled	-91,894	-3,133,174			0.0341
16	North Dakota					
17	D05 Energy Control	1,657	119,947	54	30,685	0.0724
18	D10 Limited Off Peak	628	51,707	33	19,030	0.0823
19	D11 Auto Protective Lighting	2,672	345,616			0.1293
20	D12 Small General Service	105,689	11,346,023	8,153	12,963	0.1074
21	D14 Small General TOD Service	2,336	239,332	214	10,916	0.1025
22	D16 General Service	720,208	68,253,812	3,682	195,602	0.0948
23	D17 General TOD Service	215,169	16,894,850	208	1,034,466	0.0785
24	D18 Small General TOD Service	558	63,998	101	5,525	0.1147
25	D19 Small General kWh metered	943	122,351	221	4,267	0.1297
26	D20 Peak Control	31,551	2,894,604	47	671,298	0.0917
27	D21 Peak Control Time of Day	133,251	9,441,396	14	9,517,929	0.0709
28	D22 Tier 1 Energy Control	235,413	16,122,241	66	3,566,864	0.0685
29	D34 Sm General TOD Low Watt	68	8,104	21	3,238	0.1192
30	Unbilled	-7,414	-916,645			0.1236
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	35,077,184	3,771,652,917	1,478,542	23,724	0.1075
42	Total Unbilled Rev.(See Instr. 6)	-169,113	-8,858,239	0	0	0.0524
43	TOTAL	34,908,071	3,762,794,678	1,478,542	23,610	0.1078

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	South Dakota					
4	E10 Energy Control	135	9,684	11	12,273	0.0717
5	E11 Limited Off Peak	305	22,757	8	38,125	0.0746
6	E12 Auto Protective Lighting	2,305	357,134			0.1549
7	E13 Small General Service	86,881	9,546,829	7,313	11,880	0.1099
8	E14 Small General TOD Service	2,208	250,894	354	6,237	0.1136
9	E15 General Service	676,717	64,533,719	3,628	186,526	0.0954
10	E16 General TOD Service	502,427	38,077,459	228	2,203,627	0.0758
11	E18 Small General TOD Service	59	7,748	66	894	0.1313
12	E20 Peak Control	61,513	5,930,284	77	798,870	0.0964
13	E21 Peak Control Time of Day	52,077	3,712,579	15	3,471,800	0.0713
14	E22 Energy Control	25,752	1,869,485	15	1,716,800	0.0726
15	Unbilled	-5,779	-625,452			0.1082
16	Total Commercial and Industrial	24,200,317	2,291,754,264	157,489	153,664	0.0947
17						
18	PUBLIC STREET AND HIGHWAY					
19	Minnesota					
20	A30 Street Light Co Owned	46,874	18,135,039	1,942	24,137	0.3869
21	A32 Street Light Cust Owned	29,206	2,191,292	424	68,882	0.0750
22	A34 Street Lighting Metered	35,578	2,700,919	2,678	13,285	0.0759
23	A37 Street Lighting St Paul	959	143,868	1	959,000	0.1500
24	Unbilled	1,357	859,251			0.6332
25	North Dakota					
26	D30 Street Light Co Owned	934	559,085	62	15,065	0.5986
27	D31 Street Light Cust Owned	11,762	928,484	33	356,424	0.0789
28	D32 Street Lighting Ornamental	37	3,596	2	18,500	0.0972
29	D33 Street Lighting Metered	2,165	140,842	117	18,504	0.0651
30	Unbilled	8	2,550			0.3188
31	South Dakota					
32	E30 Street Light Co Owned	837	775,546	113	7,407	0.9266
33	E31 Street Light Cust Owned	3,342	290,817	15	222,800	0.0870
34	E32 Street Lighting Metered	7,237	575,115	242	29,905	0.0795
35	E33 Street Lighting Ornamental	1,198	96,018	98	12,224	0.0801
36	Unbilled	-14	6,318			-0.4513
37	Total Public Street and Highway	141,480	27,408,740	5,727	24,704	0.1937
38						
39						
40						
41	TOTAL Billed	35,077,184	3,771,652,917	1,478,542	23,724	0.1075
42	Total Unbilled Rev.(See Instr. 6)	-169,113	-8,858,239	0	0	0.0524
43	TOTAL	34,908,071	3,762,794,678	1,478,542	23,610	0.1078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	OTHER SALES TO PUBLIC					
4	Minnesota					
5	A40 Small Municipal Pumping	7,176	969,048	944	7,602	0.1350
6	A41 Municipal Pumping	62,779	7,667,858	566	110,917	0.1221
7	A42 Fire Siren		36,093	530		
8	Unbilled	-124	550			-0.0044
9	North Dakota					
10	D40 Small Municipal Pumping	961	103,713	77	12,481	0.1079
11	D41 Municipal Pumping	12,429	1,249,599	86	144,523	0.1005
12	D42 Fire Siren		991	24		
13	Unbilled	-270	-28,998			0.1074
14	South Dakota					
15	E40 Fire Siren		2,963			
16	Total Other Sales to Public Autho	82,951	10,001,817	2,227	37,248	0.1206
17						
18	Interdepartmental Sales	6,987	692,309			0.0991
19	Total Interdepartmental	6,987	692,309			0.0991
20						
21	Footnote for Instruction 5:					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	35,077,184	3,771,652,917	1,478,542	23,724	0.1075
42	Total Unbilled Rev.(See Instr. 6)	-169,113	-8,858,239	0	0	0.0524
43	TOTAL	34,908,071	3,762,794,678	1,478,542	23,610	0.1078

Schedule Page: 304.3 Line No.: 21 Column: a

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:

A00	$ 4,833
A01	$135,032,971
A02	$ 97,806
A03	$102,501,134
A04	$ 109,025
A05	$ 1,148,622
A06	$ 134,644
A07	$ 653,626
A08	$ 27,833
A09	$ 676
A10	$ 21,689,942
A11	$ 5,945
A12	$ 1,124,094
A13	$ 56
A14	$217,833,039
A15	$212,207,742
A16	$ 421,618
A18	$ 751,886
A22	$ 64,640
A23	$ 30,329,181
A24	$ 65,220,704
A27	$ 11,476,107
A29	$ 684,330
A30	$ 995,276
A32	$ 619,749
A34	$ 754,089
A37	$ 20,345
A40	$ 197,034
A41	$ 1,658,461
A52	$ 5,168
A55	$ 7,463
A62	$ 285,655
A63	$ 134,346
Minnesota jurisdiction	$806,198,039

D01	$ 14,737,350
D02	$ 19,627
D03	$ 4,029,006
D04	$ 2,780
D05	$ 141,322
D10	$ 35,813
D11	$ 52,172
D12	$ 2,577,546
D14	$ 56,954
D16	$ 17,253,982
D17	$ 4,932,575
D18	$ 13,598
D19	$ 22,949
D20	$ 755,398
D21	$ 3,025,689
D22	$ 5,466,871
D30	$ 16,247
D31	$ 204,378

D32	$ 635
D33	$ 37,493
D34	$ 1,652
D40	$ 23,583
D41	$ 298,027
North Dakota jurisdiction	$ 53,705,648
E01	$ 8,330,338
E02	$ 951
E03	$ 10,483,481
E04	$ 1,184
E06	$ 47,095
E10	$ 37,324
E11	$ 8,597
E12	$ 49,452
E13	$ 2,134,066
E14	$ 55,018
E15	$ 16,215,228
E16	$ 11,621,768
E18	$ 1,434
E20	$ 1,466,181
E21	$ 1,214,225
E22	$ 608,825
E30	$ 15,713
E31	$ 62,280
E32	$ 136,673
E33	$ 22,328
South Dakota jurisdiction	$ 52,512,160
Total Company	$912,415,847

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NSP-Wisconsin	RQ		N/A	N/A	N/A
2	Basin Electric Power Cooperative	OS	V6	N/A	N/A	N/A
3	BP Energy Company	OS	V6	N/A	N/A	N/A
4	City of Ada, MN	OS	V6	N/A	N/A	N/A
5	City of Ada, MN	SF	V6	N/A	N/A	N /A
6	City of Ada, MN	AD	V6	N/A	N/A	N/A
7	City of Kasota, MN	OS	V6	N/A	N/A	N/A
8	City of Kasota, MN	SF	V6	N/A	N/A	N/A
9	City of Kasota, MN	AD	V6	N/A	N/A	N/A
10	Dahlberg Light and Power Co	OS	V6	N/A	N/A	N/A
11	Dahlberg Light and Power Co	SF	V6	N/A	N/A	N/A
12	Dahlberg Light and Power Co	AD	V6	N/A	N/A	N/A
13	Direct Energy Buisness Marketing, LLC	SF	V6	N/A	N/A	N/A
14	ETC Endure Energy, LLC	SF	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	ICE NGX Canada Inc	OS	V6	N/A	N/A	N/A
2	Luminant Energy Company LLC	OS	V6	N/A	N/A	N/A
3	Manitoba Hydro-Electric Board	OS	V6	N/A	N/A	N/A
4	Midcontinent Independent System Operato	OS	V6	N/A	N/A	N/A
5	Midcontinent Independent System Operato	AD	V6	N/A	N/A	N/A
6	NextEra Eenrgy Power Marketing, LLC	OS	V6	N/A	N/A	N/A
7	NextEra Eenrgy Power Marketing, LLC	SF	V6	N/A	N/A	N/A
8	North Central Power Company, Inc.	OS	V6	N/A	N/A	N/A
9	North Central Power Company, Inc.	SF	V6	N/A	N/A	N/A
10	North Central Power Company, Inc.	AD	V6	N/A	N/A	N/A
11	Northwestern Wisconsin Electric Company	OS	V6	N/A	N/A	N/A
12	Northwestern Wisconsin Electric Company	SF	V6	N/A	N/A	N/A
13	Northwestern Wisconsin Electric Company	AD	V6	N/A	N/A	N/A
14	Ohio Power Company	SF	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PJM Interconnection, LLC	SF	V6	N/A	N/A	N/A
2						
3						
4	Footnote for total $$ and mWh					
5	** Footnote from 106b					
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,367,949		350,141,408		350,141,408	1
	900,000			900,000	2
24,400			475,047	475,047	3
	34,399			34,399	4
6,547		502,551		502,551	5
36		19,394		19,394	6
	21,999			21,999	7
4,239		259,548		259,548	8
34		3,795		3,795	9
5,596	141,423	122,854		264,277	10
112,537		5,756,643		5,756,643	11
		70,049		70,049	12
41,600			1,162,690	1,162,690	13
1,600			34,400	34,400	14
6,367,949	0	350,141,408	0	350,141,408	
7,656,805	3,623,859	133,553,558	27,958,208	165,135,625	
14,024,754	**3,623,859**	**483,694,966**	**27,958,208**	**515,277,033**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
41,200			1,391,082	1,391,082	1
17,600			464,464	464,464	2
	37,500			37,500	3
6,729,664	146,371	120,087,888	3,431,352	123,665,611	4
13,097	949	262,945	-22,798	241,096	5
24,400	2,100,000		470,100	2,570,100	6
800		16,400		16,400	7
13,868	39,447	262,641		302,088	8
12,840		483,688		483,688	9
		-252		-252	10
54,876	201,771	1,078,635		1,280,406	11
125,520		4,627,616		4,627,616	12
-360		-837		-837	13
406,681			19,904,399	19,904,399	14
6,367,949	0	350,141,408	0	350,141,408	
7,656,805	3,623,859	133,553,558	27,958,208	165,135,625	
14,024,754	**3,623,859**	**483,694,966**	**27,958,208**	**515,277,033**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
20,030			647,472	647,472	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
6,367,949	0	350,141,408	0	350,141,408	
7,656,805	3,623,859	133,553,558	27,958,208	165,135,625	
14,024,754	**3,623,859**	**483,694,966**	**27,958,208**	**515,277,033**	

Schedule Page: 310 Line No.: 1 Column: a

Ownership interest or affiliation per Instruction 2:

Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc.

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

V6 - FERC Electric Tariff, First Revised Volume No. 6

Schedule Page: 310 Line No.: 3 Column: j

Financial Trading

Schedule Page: 310 Line No.: 6 Column: i

Prior Period Adjustment

Schedule Page: 310 Line No.: 9 Column: i

Prior Period Adjustment

Schedule Page: 310 Line No.: 12 Column: i

Prior Period Adjustment

Schedule Page: 310 Line No.: 13 Column: j

Financial Trading

Schedule Page: 310 Line No.: 14 Column: j

Financial Trading

Schedule Page: 310.1 Line No.: 1 Column: j

Financial Trading

Schedule Page: 310.1 Line No.: 2 Column: j

Financial Trading

Schedule Page: 310.1 Line No.: 4 Column: j

Demand - Resource Adequacy Auction, Other - Ancillary Services

Schedule Page: 310.1 Line No.: 5 Column: i

Prior Period Adjustment

Schedule Page: 310.1 Line No.: 10 Column: i

Prior Period Adjustment

Schedule Page: 310.1 Line No.: 13 Column: i

Prior Period Adjustment

Schedule Page: 310.1 Line No.: 14 Column: j

Financial Trading

Schedule Page: 310.2 Line No.: 1 Column: j

Financial Trading

Schedule Page: 310.2 Line No.: 4 Column: a

Total revenue and volumes sold will not match pages 300-1, line 11, due to differences in accounting classification associated with the Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) Interchange Agreement.

	Revenue	Mwh
page 300, line 11(b)	$165,135,625	7,656,805
page 311 total (k)	$515,277,033	14,024,754
less net interchange agreement	(350,141,408)	(6,367,949)
	$165,135,625	7,656,805

Schedule Page: 310.2 Line No.: 5 Column: a

Sales for Resale (Account No. 447). The revenue credit from sales for resale included in the formula are for bundled sales that are not included in the formula divisor.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	3,465,490	3,676,860
5	(501) Fuel	322,461,439	318,564,855
6	(502) Steam Expenses	25,430,816	24,340,610
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,698,247	4,040,486
10	(506) Miscellaneous Steam Power Expenses	15,383,472	13,924,056
11	(507) Rents	4,606,393	3,259,384
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	375,045,857	367,806,251
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,701,428	2,957,690
16	(511) Maintenance of Structures	5,715,120	5,369,444
17	(512) Maintenance of Boiler Plant	25,986,582	23,979,849
18	(513) Maintenance of Electric Plant	13,323,980	7,377,092
19	(514) Maintenance of Miscellaneous Steam Plant	11,506,279	11,965,103
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	60,233,389	51,649,178
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	435,279,246	419,455,429
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	58,197,932	65,468,746
25	(518) Fuel	121,888,518	114,361,824
26	(519) Coolants and Water	8,885,718	9,165,290
27	(520) Steam Expenses	49,629,249	50,048,519
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,824,271	2,521,413
31	(524) Miscellaneous Nuclear Power Expenses	128,488,608	131,053,296
32	(525) Rents	13,089,705	11,718,071
33	TOTAL Operation (Enter Total of lines 24 thru 32)	383,004,001	384,337,159
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	5,044,952	5,229,084
36	(529) Maintenance of Structures	142,945	419,818
37	(530) Maintenance of Reactor Plant Equipment	40,743,589	39,119,015
38	(531) Maintenance of Electric Plant	9,787,389	11,596,004
39	(532) Maintenance of Miscellaneous Nuclear Plant	32,043,555	31,371,710
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	87,762,430	87,735,631
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	470,766,431	472,072,790
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	31,859	18,122
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	369,350	425,694
48	(539) Miscellaneous Hydraulic Power Generation Expenses	449,236	121,102
49	(540) Rents	50,140	41,316
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	900,585	606,234
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	8,644	14,841
54	(542) Maintenance of Structures	37,215	81,785
55	(543) Maintenance of Reservoirs, Dams, and Waterways	207,434	30,160
56	(544) Maintenance of Electric Plant	107,266	308,887
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,397	418
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	361,956	436,091
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,262,541	1,042,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,462,689	1,456,943
63	(547) Fuel	176,923,193	134,988,213
64	(548) Generation Expenses	7,756,781	6,888,806
65	(549) Miscellaneous Other Power Generation Expenses	9,807,631	18,006,000
66	(550) Rents	6,181,665	2,655,703
67	TOTAL Operation (Enter Total of lines 62 thru 66)	202,131,959	163,995,665
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,783,205	1,141,460
70	(552) Maintenance of Structures	9,901,944	6,722,810
71	(553) Maintenance of Generating and Electric Plant	9,706,726	10,371,752
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,667,049	2,489,712
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	25,058,924	20,725,734
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	227,190,883	184,721,399
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	731,074,163	705,284,433
77	(556) System Control and Load Dispatching	1,686,912	1,348,426
78	(557) Other Expenses	91,735,443	63,768,822
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	824,496,518	770,401,681
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,958,995,619	1,847,693,624
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	12,044,941	12,049,937
84			
85	(561.1) Load Dispatch-Reliability		2,548
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,907,757	4,468,695
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	7,737,718	7,411,149
89	(561.5) Reliability, Planning and Standards Development	1,270	5,299
90	(561.6) Transmission Service Studies	4	-37
91	(561.7) Generation Interconnection Studies	-17,939	-3,190
92	(561.8) Reliability, Planning and Standards Development Services	2,871,119	2,830,128
93	(562) Station Expenses	2,835,783	1,242,591
94	(563) Overhead Lines Expenses	543,045	1,242,924
95	(564) Underground Lines Expenses	34,349	5,763
96	(565) Transmission of Electricity by Others	309,789,754	206,928,323
97	(566) Miscellaneous Transmission Expenses	6,474,236	116,450,515
98	(567) Rents	2,889,594	3,498,285
99	TOTAL Operation (Enter Total of lines 83 thru 98)	350,111,631	356,132,930
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	38,639	118,220
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,794,615	4,916,167
108	(571) Maintenance of Overhead Lines	6,667,823	8,110,161
109	(572) Maintenance of Underground Lines	24,862	22,321
110	(573) Maintenance of Miscellaneous Transmission Plant	21,151	39,528
111	TOTAL Maintenance (Total of lines 101 thru 110)	11,547,090	13,206,397
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	361,658,721	369,339,327

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	213,710	250,256
116	(575.2) Day-Ahead and Real-Time Market Facilitation	90,488	106,626
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	300	12,234
120	(575.6) Market Monitoring and Compliance	1,997	12,811
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,493,394	9,810,597
122	(575.8) Rents	11,027	
123	Total Operation (Lines 115 thru 122)	10,810,916	10,192,524
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	10,810,916	10,192,524
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	7,611,747	11,150,217
135	(581) Load Dispatching	1,624,788	256,427
136	(582) Station Expenses	4,463,218	4,528,926
137	(583) Overhead Line Expenses	1,757,946	2,522,941
138	(584) Underground Line Expenses	1,064,811	7,021,215
139	(585) Street Lighting and Signal System Expenses	187,718	1,208,765
140	(586) Meter Expenses	1,682,761	942,016
141	(587) Customer Installations Expenses	1,267,028	3,136,375
142	(588) Miscellaneous Expenses	27,877,917	14,047,616
143	(589) Rents	3,925,985	4,300,647
144	TOTAL Operation (Enter Total of lines 134 thru 143)	51,463,919	49,115,145
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	92,286	95,015
147	(591) Maintenance of Structures	41,783	2,519
148	(592) Maintenance of Station Equipment	8,195,160	8,227,071
149	(593) Maintenance of Overhead Lines	46,810,911	41,521,691
150	(594) Maintenance of Underground Lines	6,203,726	7,085,172
151	(595) Maintenance of Line Transformers	381,758	2,288,415
152	(596) Maintenance of Street Lighting and Signal Systems	2,461,662	1,439,756
153	(597) Maintenance of Meters	116,148	102,106
154	(598) Maintenance of Miscellaneous Distribution Plant	6,928,512	1,288,711
155	TOTAL Maintenance (Total of lines 146 thru 154)	71,231,946	62,050,456
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	122,695,865	111,165,601
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	77,304	108,716
160	(902) Meter Reading Expenses	21,230,378	19,773,721
161	(903) Customer Records and Collection Expenses	20,760,549	22,506,351
162	(904) Uncollectible Accounts	13,718,359	13,011,947
163	(905) Miscellaneous Customer Accounts Expenses	250	-81
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,786,840	55,400,654

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	101,566,235	104,765,143
169	(909) Informational and Instructional Expenses	1,385,792	1,778,286
170	(910) Miscellaneous Customer Service and Informational Expenses	314,922	133,259
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	103,266,949	106,676,688
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	66	4,808
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	66	4,808
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	83,040,317	85,857,392
182	(921) Office Supplies and Expenses	59,319,663	60,480,276
183	(Less) (922) Administrative Expenses Transferred-Credit	39,870,986	47,462,273
184	(923) Outside Services Employed	33,023,798	30,014,840
185	(924) Property Insurance	731,717	2,706,000
186	(925) Injuries and Damages	15,155,347	11,399,976
187	(926) Employee Pensions and Benefits	84,162,025	83,620,476
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	6,447,393	6,940,705
190	(929) (Less) Duplicate Charges-Cr.	5,602,402	5,576,918
191	(930.1) General Advertising Expenses	4,073,171	3,085,801
192	(930.2) Miscellaneous General Expenses	3,614,161	3,451,951
193	(931) Rents	34,485,243	34,251,854
194	TOTAL Operation (Enter Total of lines 181 thru 193)	278,579,447	268,770,080
195	Maintenance		
196	(935) Maintenance of General Plant	687,260	1,219,769
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	279,266,707	269,989,849
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,892,481,683	2,770,463,075

Schedule Page: 320 Line No.: 64 Column: b

Account No. 548 Generation Expenses	$	7,756,781
Account No. 548.1 Operation of Energy Storage Equipment		0
	$	7,756,781

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 64 Column: c

Account No. 548 Generation Expenses	$	6,888,806
Account No. 548.1 Operation of Energy Storage Equipment		0
	$	6,888,806

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: b

Account No. 553 Maintenance of Generating and Electric Plant	$	9,706,726
Account No. 553.1 Maintenance of Energy Storage Equipment		0
	$	9,706,726

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 71 Column: c

Account No. 553 Maintenance of Generating and Electric Plant	$	10,371,752
Account No. 553.1 Maintenance of Energy Storage Equipment		0
	$	10,371,752

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: b

Account No. 555 Purchased Power	$	731,194,515
Account No. 555.1 Power Purchased for Storage Operations		(120,352)
	$	731,074,163

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 76 Column: c

Account No. 555 Purchased Power	$	705,308,410
Account No. 555.1 Power Purchased for Storage Operations		(23,977)
	$	705,284,433

See Note 13 to the Financial Statements

Schedule Page: 320 Line No.: 78 Column: b

Includes $44,821,290 of fixed costs and $16,271,338 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 320 Line No.: 78 Column: c

Includes $48,769,506 of fixed costs and $18,006,880 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through a FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 90 Column: c

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing transmission service studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.6.

Schedule Page: 320 Line No.: 91 Column: b

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 91 Column: c

Credit balance results from Pension, Insurance and Taxes on Company labor billed for performing generation interconnection studies being recorded to Account Nos. 408.1, 925 and 926 while the receivable related to performing the studies is recorded to Account No. 561.7.

Schedule Page: 320 Line No.: 96 Column: b

Includes $96,779,594 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 320 Line No.: 97 Column: c

Includes $110,457,340 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the FERC-approved Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through the FERC-approved Interchange Agreement.

Schedule Page: 320 Line No.: 112 Column: b

Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the FERC-approved Interchange Agreement.

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Adams Wind Generations, LLC	LU		N/A	N/A	N/A
2	Agassiz Beach LLC	LU		N/A	N/A	N/A
3	American Electric Power	OS		N/A	N/A	N/A
4	Aurora Distributed Solar, LLC	AD		N/A	N/A	N/A
5	Aurora Distributed Solar, LLC	LU		N/A	N/A	N/A
6	Benson Power, LLC	LU		N/A	N/A	N/A
7	Best Power International LLC	LU		N/A	N/A	N/A
8	Big Blue	LU		N/A	N/A	N/A
9	Bisson Windfarm, L.L.C.	LU		N/A	N/A	N/A
10	Boeve Windfarm, L.L.C.	LU		N/A	N/A	N/A
11	Byllesby	LU		2	N/A	N/A
12	Cannon Falls Energy Center	LU		346	N/A	N/A
13	Carleton College	LU		N/A	N/A	N/A
14	CG Windfarm, L.L.C.	LU		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Chanarambie Power Partners, L.L.C.	LU		N/A	N/A	N/A
2	Cisco Wind Energy, L.L.C.	LU		N/A	N/A	N/A
3	Citigroup Energy, Inc.	OS		N/A	N/A	N/A
4	Covanta Hennepin Energy Resource Co LP	LU		34	N/A	N/A
5	Dairyland Electric Cooperative Incorpd	LU		N/A	N/A	N/A
6	Danielson Wind Farms, LLC	LU		N/A	N/A	N/A
7	Diamond K Dairy	LU		N/A	N/A	N/A
8	Dragonfly Solar, LLC	LU		N/A	N/A	N/A
9	East Ridge	LU		N/A	N/A	N/A
10	EnXco, Inc.	AD		N/A	N/A	N/A
11	EnXco, Inc.	OS		N/A	N/A	N/A
12	ERCOT	OS		N/A	N/A	N/A
13	Ewington Energy Systems, LLC	LU		N/A	N/A	N/A
14	Fenton Power Partners I, L.L.C.	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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1	Fey Windfarm, L.L.C.	LU		N/A	N/A	N/A
2	FPL Energy Mower County, L.L.C.	LU		N/A	N/A	N/A
3	Garwin McNeilus	LU		N/A	N/A	N/A
4	Grant County Wind, LLC	LU		N/A	N/A	N/A
5	Hastings Lock & Dam	LU		2	N/A	N/A
6	Hilltop Power, L.L.C.	LU		N/A	N/A	N/A
7	Jeffers Wind Energy Center	LU		N/A	N/A	N/A
8	JJN Windfarm, LLC	LU		N/A	N/A	N/A
9	Kas Brothers Windfarm, L.L.C.	LU		N/A	N/A	N/A
10	K-Brink Windfarm, L.L.C.	LU		N/A	N/A	N/A
11	KODA Energy, LLC	LU		N/A	N/A	N/A
12	Lake Benton Power Partners, L.L.C.	LU		N/A	N/A	N/A
13	Laurentian Energy Authority, L.L.C.	AD		N/A	N/A	N/A
14	Laurentian Energy Authority, L.L.C.	LU		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
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1	LCO Hydro	LU		N/A	N/A	N/A
2	Lincoln Heights Wind Holdings	LU		N/A	N/A	N/A
3	Lower Colorado River Authority	OS		N/A	N/A	N/A
4	LSP Cottage Grove Incorporated	AD		N/A	N/A	N/A
5	LSP Cottage Grove Incorporated	LU		245	N/A	N/A
6	Manitoba Hydro	LU		350	N/A	N/A
7	Mankato Energy Center, L.L.C.	AD		N/A	N/A	N/A
8	Mankato Energy Center, L.L.C.	LU		375	N/A	N/A
9	Marshall Solar	LU		N/A	N/A	N/A
10	Metro Wind LLC	LU		N/A	N/A	N/A
11	Midcontinental ISO	AD		N/A	N/A	N/A
12	Midcontinental ISO	SF		N/A	N/A	N/A
13	MinnDakota	LU		N/A	N/A	N/A
14	Miscellaneous	OS		N/A	N/A	N/A
	Total					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER (Account 555)
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1	Moraine Wind, L.L.C.	LU		N/A	N/A	N/A
2	NAE Lakota Ridge, LLC	AD		N/A	N/A	N/A
3	NAE Lakota Ridge, LLC	LU		N/A	N/A	N/A
4	NAE Shaokatan, LLC	LU		N/A	N/A	N/A
5	NAE Shaokatan Hills, LLC	AD		N/A	N/A	N/A
6	NAE Shaokatan Hills, LLC	LU		N/A	N/A	N/A
7	Natural Gas Exchange Inc.	OS		N/A	N/A	N/A
8	Neshkoro (Neshonoc)	LU		0	N/A	N/A
9	New England ISO	OS		N/A	N/A	N/A
10	New Ulm	OS	NAEMA	N/A	N/A	N/A
11	New York ISO	OS		N/A	N/A	N/A
12	North Community Turbines LLC	LU		N/A	N/A	N/A
13	North Star Solar	LU		N/A	N/A	N/A
14	North Wind Turbines LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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1	NSP-M Solar Gardens	LU		N/A	N/A	N/A
2	Odell Wind Farm, LLC	LU		N/A	N/A	N/A
3	Olsen Windfarms	LU		N/A	N/A	N/A
4	Otter Tail Power Company	AD		N/A	N/A	N/A
5	Pine Bend	LU		N/A	N/A	N/A
6	Pipestone	LU		N/A	N/A	N/A
7	PJM Interconnection LLC	AD		N/A	N/A	N/A
8	PJM Interconnection LLC	OS		N/A	N/A	N/A
9	Prairie Rose Wind LLC	LU		N/A	N/A	N/A
10	Rapidan Hydroelectric Facility	LU		3	N/A	N/A
11	Ridgewind Power Partners, LLC	LU		N/A	N/A	N/A
12	Rock County Energy	LU		N/A	N/A	N/A
13	Rock Ridge Power Partners LLC	LU		N/A	N/A	N/A
14	Ruthton Ridge LLC	LU		N/A	N/A	N/A
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(Including power exchanges)

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1	SAF Hydroelectric, L.L.C.	LU		N/A	N/A	N/A
2	Shane's Wind Machine LLC	LU		N/A	N/A	N/A
3	Slayton Solar, LLC	LU		N/A	N/A	N/A
4	South Ridge	LU		N/A	N/A	N/A
5	Southern Minnesota Municipal Power Agy	OS		N/A	N/A	N/A
6	Southwest Power Pool Electric Energy	AD		N/A	N/A	N/A
7	Southwest Power Pool Electric Energy	OS		N/A	N/A	N/A
8	St Cloud	LU		7	N/A	N/A
9	St. Olaf College	AD		N/A	N/A	N/A
10	St. Olaf College	LU		N/A	N/A	N/A
11	St. Paul Cogeneration	LU		N/A	N/A	N/A
12	TG Windfarm, L.L.C.	LU		N/A	N/A	N/A
13	Tholen	LU		N/A	N/A	N/A
14	Tofteland Windfarm, L.L.C.	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Uilk Wind Farm, LLC	LU		N/A	N/A	N/A
2	University of Minnesota	LU		N/A	N/A	N/A
3	Valley View Transmission	LU		N/A	N/A	N/A
4	Velva Windfarm, LLC	LU		N/A	N/A	N/A
5	Viking Wind Partners	LU		N/A	N/A	N/A
6	Western Area Power Administration	LU	NAEMA, WSPP	N/A	N/A	N/A
7	Westridge Windfarm, L.L.C.	LU		N/A	N/A	N/A
8	Windcurrent Farms, L.L.C.	LU		N/A	N/A	N/A
9	Windvest	LU		N/A	N/A	N/A
10	Winona County Wind LLC	AD		N/A	N/A	N/A
11	Winona County Wind LLC	LU		N/A	N/A	N/A
12	WM Renewable Energy, LLC	LU		N/A	N/A	N/A
13	Woodstock Hills, L.L.C.	LU		N/A	N/A	N/A
14	Woodstock Municipal Wind, LLC	LU		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Zephyr Wind	LU		N/A	N/A	N/A
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
52,099				3,594,818		3,594,818	1
4,357				98,413		98,413	2
3,339					163,814	163,814	3
-34				-3,232		-3,232	4
188,886				18,028,239		18,028,239	5
150,262				27,129,882		27,129,882	6
1,759				158,430		158,430	7
118,512				5,995,914		5,995,914	8
4,119				140,072		140,072	9
5,346				179,074		179,074	10
13,153			423,077	283,729		706,806	11
114,046			27,218,048	8,114,384		35,332,432	12
3,897				128,592		128,592	13
2,298				78,120		78,120	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
211,136				5,594,654		5,594,654	1
23,205				952,824		952,824	2
8,400					789,600	789,600	3
203,431				5,276,232		5,276,232	4
17,200				164,551		164,551	5
46,149				3,156,622		3,156,622	6
-43				-2,691		-2,691	7
197				16,472		16,472	8
23,978				791,205		791,205	9
					-80	-80	10
					-66,938	-66,938	11
-23,200					192,599	192,599	12
58,779				2,311,803		2,311,803	13
645,208				30,579,033		30,579,033	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,229				183,020		183,020	1
262,300				11,328,795		11,328,795	2
74,762				2,456,153		2,456,153	3
54,123				3,739,897		3,739,897	4
13,592			436,243	261,060		697,303	5
3,004				156,201		156,201	6
159,825				5,808,727		5,808,727	7
4,082				136,747		136,747	8
3,178				121,249		121,249	9
5,629				188,582		188,582	10
100,021				8,424,575		8,424,575	11
455,115				12,059,843		12,059,843	12
				244,494		244,494	13
138,398				17,345,479		17,345,479	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
12,302				176,822		176,822	1
15,170				500,620		500,620	2
33,600					887,478	887,478	3
				-8,024		-8,024	4
258,522			14,628,066	8,584,434		23,212,500	5
1,637,153			35,317,115	104,722,722		140,039,837	6
			-511	-133,258		-133,769	7
486,324			35,234,980	15,442,683		50,677,663	8
107,319				6,430,631		6,430,631	9
759				17,174		17,174	10
-9,181				76,591		76,591	11
2,769,281				56,872,878		56,872,878	12
494,144				19,271,610		19,271,610	13
114,676					860,841	860,841	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
307,348				13,636,383		13,636,383	1
6,257				296,786		296,786	2
22,306				1,013,526		1,013,526	3
24,951				564,787		564,787	4
7,214				341,901		341,901	5
30,345				1,380,534		1,380,534	6
31,200					1,380,414	1,380,414	7
1,767			37,567	35,791		73,358	8
					16,162	16,162	9
			405,000			405,000	10
					-732	-732	11
45,340				2,992,426		2,992,426	12
195,387				12,456,856		12,456,856	13
43,551				2,874,371		2,874,371	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
595,562				72,799,030		72,799,030	1
759,749				17,531,072		17,531,072	2
1,975				74,911		74,911	3
				-65,001		-65,001	4
9,496				457,618		457,618	5
22,156				731,182		731,182	6
					-926	-926	7
381,814				14,362,413	7,220,570	21,582,983	8
623,329				24,051,970		24,051,970	9
18,820			362,776	363,186		725,962	10
80,230				5,212,761		5,212,761	11
22,889				755,309		755,309	12
5,105				168,445		168,445	13
40,234				915,073		915,073	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
51,374				2,603,091		2,603,091	1
6,236				205,792		205,792	2
2,622				298,954		298,954	3
3,798				125,345		125,345	4
9,671				92,382		92,382	5
-58				-786		-786	6
4,500				281,909		281,909	7
51,166			1,495,094	1,242,240		2,737,334	8
3				103		103	9
24				805		805	10
161,318				23,861,117		23,861,117	11
4,637				157,644		157,644	12
41,484				1,368,957		1,368,957	13
4,253				144,615		144,615	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
12,074				836,487		836,487	1
2,736				64,229		64,229	2
27,443				1,750,873		1,750,873	3
25,878				853,980		853,980	4
33,267				1,097,781		1,097,781	5
11,785				282,892		282,892	6
2,497				84,895		84,895	7
5,759				179,303		179,303	8
1,824				60,177		60,177	9
-1				7		7	10
-31				-2,062		-2,062	11
35,536				1,599,113		1,599,113	12
6,401				276,082		276,082	13
957				64,905		64,905	14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
112,522				6,414,901		6,414,901	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
12,972,506			115,557,455	604,073,906	11,442,802	731,074,163	

Schedule Page: 326 Line No.: 3 Column: l
Financial Trading
Schedule Page: 326 Line No.: 4 Column: k
Prior Period Adjustment
Schedule Page: 326 Line No.: 6 Column: a
On June 29, 2018 NSP-Minnesota acquired the Benson Power Facility. For additional information see page 108 item 3.
Schedule Page: 326.1 Line No.: 3 Column: l
Financial Trading
Schedule Page: 326.1 Line No.: 10 Column: l
Prior Period Adjustment
Schedule Page: 326.1 Line No.: 11 Column: l
Comp. for Non-Renewable Energy Rebate
Schedule Page: 326.1 Line No.: 12 Column: l
Financial Trading
Schedule Page: 326.2 Line No.: 13 Column: k
Prior Period Adjustment
Schedule Page: 326.3 Line No.: 3 Column: l
Financial Trading
Schedule Page: 326.3 Line No.: 4 Column: k
Prior Period Adjustment
Schedule Page: 326.3 Line No.: 7 Column: k
Prior Period Adjustment
Schedule Page: 326.3 Line No.: 11 Column: k
Prior Period Adjustment
Schedule Page: 326.3 Line No.: 14 Column: l
Miscellaneous
Schedule Page: 326.4 Line No.: 2 Column: k
Prior Period Adjustment
Schedule Page: 326.4 Line No.: 5 Column: k
Prior Period Adjustment
Schedule Page: 326.4 Line No.: 7 Column: l
Financial Trading
Schedule Page: 326.4 Line No.: 9 Column: l
Financial Trading
Schedule Page: 326.4 Line No.: 10 Column: j
Capacity Credits
Schedule Page: 326.4 Line No.: 11 Column: l
Financial Trading
Schedule Page: 326.5 Line No.: 4 Column: k
Prior Period Adjustment
Schedule Page: 326.5 Line No.: 7 Column: l
Prior Period Adjustment
Schedule Page: 326.5 Line No.: 8 Column: l
Financial Trading
Schedule Page: 326.6 Line No.: 5 Column: k
Financial Trading
Schedule Page: 326.6 Line No.: 6 Column: k
Prior Period Adjustment
Schedule Page: 326.6 Line No.: 7 Column: k
Financial Trading
Schedule Page: 326.6 Line No.: 9 Column: k
Prior Period Adjustment
Schedule Page: 326.7 Line No.: 10 Column: k
Prior Period Adjustment

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	East Grand Forks, City of	WAPA	East Grand Forks, City of	OS
2	Granite Falls, City of	WAPA	Granite Falls, City of	OS
3	Great River Energy	Various	Various	FNO
4	Midcontinent ISO (MISO)	Various	Various	
5	Missouri River Energy Services (MRES)	Various	Various	FNO
6	Sioux Falls, City of	WAPA	Sioux Falls, City of	OS
7	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS
8	Southern MN Municipal Power Agency	Various	Various	FNO
9	University of North Dakota	WAPA	University of North Dakota	OS
10	Wisconsin Public Power, Inc. (WPPI)	MP	WPPI	OS
11	Northern States Power-Wisconsin	Various	Various	OS
12				
13				
14				
15				
16				
17				
18				
19	**Footnote from page 106b			
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
483	WAPA	East Grand Forks				1
436	WAPA	Granite Falls, City				2
Various	Various	Various				3
MISO OATT	Various	Various				4
304	Various	Various				5
484	WAPA	Sioux Falls, City of				6
385	WAPA	SDSP				7
304	Various	Various				8
440	WAPA	UND				9
466						10
437	Various	Various				11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**0**	**0**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		51,717	51,717	1
		16,477	16,477	2
37,544,857		126,983	37,671,840	3
115,090,129	58,420,357		173,510,486	4
5,171,974			5,171,974	5
		173,653	173,653	6
		13,812	13,812	7
6,177,115			6,177,115	8
		63,879	63,879	9
		40,320	40,320	10
62,491,775			62,491,775	11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
226,475,850	**58,420,357**	**486,841**	**285,383,048**	

Schedule Page: 328 Line No.: 1 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 2 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 3 Column: e

28, 304, OA97-25-000 et al.

Schedule Page: 328 Line No.: 3 Column: m

Schedule 2 Revenue

Schedule Page: 328 Line No.: 4 Column: d

FNO, LFP, SFP, NF

Schedule Page: 328 Line No.: 4 Column: l

MISO Schedule 26-A revenue

Schedule Page: 328 Line No.: 6 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 7 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 9 Column: m

Facilities Charge

Schedule Page: 328 Line No.: 10 Column: m

Meter Charge

Schedule Page: 328 Line No.: 11 Column: a

Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc.

Schedule Page: 328 Line No.: 11 Column: b

Reimbursement from NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Schedule Page: 328 Line No.: 19 Column: a

Revenues from Transmission of Electricity from Others (account 456.1). The revenue credit from transmission of electricity of others included in the formula are from loads that are not included in the formula divisor, and for transmission charges associated with Schedule 26, 26A, 37 and 38 of the MISO OATT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Basin Electric Power	OS					2,400	2,400
2	Central MN Municipal Pw	FNS			890,725			890,725
3	Dairyland Power	OS					18,099	18,099
4	Great River Energy	FNS			36,416,651			36,416,651
5	McLeod Coop Power	OLF			25,885			25,885
6	Midcontinent Ipt (MISO)				95,651,937	56,860,076	1,000	152,513,013
7	MN Muncipal Pwr Agy	FNS			1,206,990			1,206,990
8	Minnkota Power Coop	OLF				21,437	780,000	801,437
9	Missouri Riv Engy Serv	FNS			2,005,586			2,005,586
10	Northwestern Wis Elect	FNS			606,598			606,598
11	Otter Tail Pwr Co	OS					928,471	928,471
12	Southern MN Muncipl Pwr	FNS			15,675,235			15,675,235
13	Southwest Power Pool	FNS			80,880	369		81,249
14	Stearns Coop Electric					542	2,796	3,338
15	Rochester Public Util	FNS			1,834,483			1,834,483
16	Northern States Pwr-WI	OLF			96,779,594			96,779,594
	TOTAL				251,174,564	56,882,424	1,732,766	309,789,754

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

Meter Agent Service Charges

Schedule Page: 332 Line No.: 3 Column: g

Facility Charges

Schedule Page: 332 Line No.: 5 Column: b

Two year notification required for termination

Schedule Page: 332 Line No.: 6 Column: b

LFP, FNS, FNO

Schedule Page: 332 Line No.: 6 Column: f

MISO Schedule 26-A expense & MISO Admin FERC fee

Schedule Page: 332 Line No.: 6 Column: g

2018 MISO Annual Membership Fee

Schedule Page: 332 Line No.: 8 Column: b

Four year notification required for termination

Schedule Page: 332 Line No.: 8 Column: g

Fixed Transmission Service Charge

Schedule Page: 332 Line No.: 11 Column: g

Interconnection Upgrade fixed charge

Schedule Page: 332 Line No.: 14 Column: b

OS, LFP- Two year notification required for termination

Schedule Page: 332 Line No.: 14 Column: g

Fixed facility charge

Schedule Page: 332 Line No.: 16 Column: a

Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc.

Schedule Page: 332 Line No.: 16 Column: b

Reimbursement for NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,882,933
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	435,688
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Director Fees and Expenses	1,253,852
7	SEC Filing Expenses	41,688
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46	TOTAL	3,614,161

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			29,477,794		29,477,794
2	Steam Production Plant	94,171,586	-13,759,035		-1,070,100	79,342,451
3	Nuclear Production Plant	144,691,298	-10,439,461			134,251,837
4	Hydraulic Production Plant-Conventional	1,389,817			-67,063	1,322,754
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	110,654,817	3,158,748	638,553	-2,507,150	111,944,968
7	Transmission Plant	69,204,755	5,255		-1,263,061	67,946,949
8	Distribution Plant	112,501,727	64,211			112,565,938
9	Regional Transmission and Market Operation					
10	General Plant	22,251,009			-1,473	22,249,536
11	Common Plant-Electric	23,431,868	11,300	36,947,689	107,216	60,498,073
12	TOTAL	578,296,877	-20,958,982	67,064,036	-4,801,631	619,600,300

B. Basis for Amortization Charges

ACCOUNT 404
Column (d) Computer software is amortized over its expected useful life of 3, 5, 7, 10 and 15 years

ACCOUNT 405
Column (e) Prefunded AFUDC recorded as Other Deferred Credits (Account 253) is amortized over the life of the property, and thus appears as a credit to expense

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production						
13	310	8,562					
14	311	290,376					
15	312	1,451,999					
16	314	315,655					
17	315	186,265					
18	316	53,966					
19	317	3,894					
20	Subtotal Steam	2,310,717					
21							
22	Nuclear Production						
23	320	1,762					
24	321	564,215					
25	322	1,780,427					
26	323	533,445					
27	324	502,556					
28	325	206,663					
29	326	-6,803					
30	Subtotal Nuclear	3,582,265					
31							
32	Hydro Production						
33	330	1,693					
34	331	1,388					
35	332	10,948					
36	333	10,107					
37	334	3,257					
38	335	61					
39	337						
40	Subtotal Hydro	27,454					
41							
42	Other Production						
43	340	26,240					
44	341	264,148					
45	342	55,960					
46	343	69,901					
47	344	2,183,092					
48	345	279,112					
49	346	32,161					
50	347	81,039					

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	348	4,129					
13	Subtotal Other	2,995,782					
14							
15	Transmission						
16	350	158,782					
17	352	111,985	70.00	-5.00	1.51	R5	58.75
18	353	1,233,595	56.00	-15.00	2.07	R2	44.63
19	354	118,289	75.00	-35.00	1.85	R4	42.73
20	355	1,390,835	62.00	-50.00	2.43	R2	55.94
21	356	567,435	67.00	-35.00	2.03	R1	58.38
22	357	28,959	73.00		1.38	R4	62.13
23	358	37,271	50.00	-5.00	2.12	R3	39.20
24	359.1	173					
25	Subtotal Transmission	3,647,324					
26							
27	Distribution						
28	360	17,487					
29	361	52,212	63.00	-30.00	2.07	R2.5	47.26
30	362	648,893	53.00	-25.00	2.37	R2	37.99
31	364	427,564	47.00	-120.00	4.69	R1	34.83
32	365	480,965	39.00	-25.00	3.21	L0	30.40
33	366	305,940	56.00	-20.00	2.15	R3	42.12
34	367	1,164,798	49.00	-10.00	2.25	R1.5	36.62
35	368	435,958	32.00	-5.00	3.23		18.27
36	368	23,116	25.00	-7.00	4.20		12.71
37	369	84,399	42.00	-85.00	4.43	R1.5	24.76
38	369	228,978	44.00	-5.00	2.40	R4	25.07
39	370	108,139	15.00	-5.00	6.90		8.64
40	371	9,895					
41	371	817					
42	371	640					
43	373	71,196	29.00	-40.00	4.84	L0	22.19
44	374	8,001					
45	Subtotal Distribution	4,068,998					
46							
47	General						
48	389	4,484					
49	390	69,397	55.00	-20.00	2.27	R1.5	36.29
50	390	552				SQ	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	391	29,143	20.00		4.48		10.22
13	391	35,999	6.00		15.78		4.00
14	392	4,958	10.00	5.00	8.98		6.65
15	392	31,863	10.00	10.00	8.07		5.03
16	392	19,953	12.00	20.00	6.29		7.71
17	392	112,354	12.00	15.00	6.63		7.50
18	393	1,632	20.00		4.60		11.33
19	394	94,244	15.00		6.25		9.38
20	395	3,071	10.00		9.17		5.36
21	396	48,432	12.00	15.00	6.64		7.52
22	397	17,117	10.00		8.68		3.73
23	397	36,599	10.00		9.89		9.08
24	397	7,096	15.00		6.53		12.66
25	397	49,380	15.00		5.92		7.39
26	398	3,349	15.00		4.74		4.06
27	Subtotal General	569,623					
28							
29	TOTAL	17,202,163					
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Schedule Page: 336 Line No.: 1 Column: d

The Amortization of Limited Term Electric Plant within Account 404 includes the following:

Intangible Plant	$ 16,777,996
Nuclear Production Plant	12,592,970
Hydraulic Production Plant-Conventional	106,828
Total	$ 29,477,794

Schedule Page: 336 Line No.: 7 Column: b

Transmission Serving Production $ 1,796,225

Schedule Page: 336 Line No.: 8 Column: b

Distribution Serving Production $ 81,132

Schedule Page: 336 Line No.: 11 Column: b

NSP-Minnesota received approval from the Minnesota Public Utilities Commission and FERC to amortize the regulatory asset related to the theoretical excess depreciation reserve (MPUC Docket No. E,G002/D-17-147 and FERC Docket No. ER18-913-001, respectively). The unwinding of the regulatory asset is recorded as an increase to regulatory debits for FERC presentation with an offsetting entry to depreciation expense and accumulated depreciation, resulting in no net impact to the balance sheet or income statement. The amounts below were included in FERC Account 403 Depreciation Expense in the current year by functional class:

Distribution Plant	$ (5,615,890)
Transmssion Plant	(4,801,830)
General Plant	(255,304)
Total	$ (10,673,024)

Schedule Page: 336.1 Line No.: 35 Column: a

368 Line Transformers

Schedule Page: 336.1 Line No.: 36 Column: a

368 Line Capacitors

Schedule Page: 336.1 Line No.: 37 Column: a

369 Overhead Services

Schedule Page: 336.1 Line No.: 38 Column: a

369 Underground Services

Schedule Page: 336.1 Line No.: 40 Column: a

371 Installation on Customer Premises (Minnesota)

Schedule Page: 336.1 Line No.: 41 Column: a

371 Installation on Customer Premises (South Dakota)

Schedule Page: 336.1 Line No.: 42 Column: a

371 Installation on Customer Premises (North Dakota)

Schedule Page: 336.1 Line No.: 49 Column: a

390 Structures and Improvements

Schedule Page: 336.1 Line No.: 50 Column: a

390 Structures and Improvements - Leasehold Improvements

Schedule Page: 336.1 Line No.: 50 Column: c

Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.

Schedule Page: 336.1 Line No.: 50 Column: e

Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.

Schedule Page: 336.1 Line No.: 50 Column: g

Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.

Schedule Page: 336.2 Line No.: 12 Column: a

391 Office Furniture and Equipment

Schedule Page: 336.2 Line No.: 13 Column: a

391 Network Equipment

Schedule Page: 336.2 Line No.: 14 Column: a

392 Transportation Equipment - Automobiles

Schedule Page: 336.2 Line No.: 15 Column: a

392 Transportation Equipment - Light Trucks

Schedule Page: 336.2 Line No.: 16 Column: a

392 Transportation Equipment - Trailers

Schedule Page: 336.2 Line No.: 17 Column: a

392 Transportation Equipment - Heavy Trucks

Schedule Page: 336.2 Line No.: 21 Column: a

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

	Charged to Clearing Accts	Depreciable Plant Base
392 Transportation Equipment	$ 10,269,290	$ 169,128,000
396 Power Operated Equipment	3,297,811	48,432,000
Total	$ 13,567,101	$ 217,560,000

Schedule Page: 336.2 Line No.: 22 Column: a

397 Communication Equipment

Schedule Page: 336.2 Line No.: 23 Column: a

397 Communication Equipment - Two Way

Schedule Page: 336.2 Line No.: 24 Column: a

397 Communication Equipment - AMR

Schedule Page: 336.2 Line No.: 25 Column: a

397 Communication Equipment - EMS

Schedule Page: 336.2 Line No.: 29 Column: b

Footnotes: Section C

(1) Column (b) Computation:
Depreciable Plant Balances are an average of the beginning and ending plant balance for the year.

(2) Column (c) through (g):
Subaccounts 311-348: A remaining life technique is applied to each generating facility. Black Dog Unit 6 was added in 2018, subaccounts 341-346. The approved life for Black Dog Unit 6 as of March 2018 is 40 years with a -5% net salvage (Docket No. EG002-D-18-162). No other changes to the underlying factors presented in columns (c) through (g) have occurred since filing the 2016 FERC Form 1.

(3) P337 Line 23 - 29 (d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning costs are recovered using an external sinking fund calculation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	MINNESOTA PUBLIC UTILITIES COMMISSION				
2	Assessments	4,956,956		4,956,956	
3	Assessments	916,756		916,756	
4	GR15-826 2016 Retail Rate Case		830,324	830,324	
5					
6	NORTH DAKOTA PUBLIC SERVICE COMMISSION				
7	Assessments	138,389		138,389	
8	Assessments	268		268	
9	PU-12-813 Resource Treatment Framework		13,313	13,313	
10					
11	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION				
12	Assessments	331,844		331,844	
13	Retail Rate Case Settlement		93,706	93,706	
14					
15	Other				
16	Mandated Notices		1,289	1,289	
17	Mandated Notices		113	113	
18	Miscellaneous		81,572	81,572	
19					
20					
21					
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23					
24					
25					
26					
27					
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45					
46	TOTAL	6,344,213	1,020,317	7,364,530	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	4,956,956					2
Gas	928	916,756					3
Electric	928	830,324		186	835,000		4
							5
							6
Electric	928	138,389					7
Gas	928	268					8
Electric	928	13,313					9
							10
							11
Electric	928	331,844					12
Electric	928	93,706					13
							14
							15
Electric	928	1,289					16
Gas	928	113					17
Electric	928	81,572					18
							19
							20
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		7,364,530			835,000		46

Schedule Page: 350 Line No.: 4 Column: k

GR15-826 - 48 month amortization period ending Dec. 31, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	B(1)	Electric Power Research Institute
2		
3	B(2)	Edison Electric Institute
4		
5	B(4)	Renewable Development Fund
6		
7	B(5)	Total
8		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
	3,016,663	Various	3,016,663		1
					2
	1,060,154	Various	1,060,154		3
					4
	5,174,230	Various	5,174,230		5
					6
	9,251,047	253	9,251,047		7
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Schedule Page: 352 Line No.: 1 Column: e

Accounts charged:

107	$119,163
506	300
517	199,750
524	2,237,246
921	69,026
923	7,880
930.2	383,298
	$3,016,663

Schedule Page: 352 Line No.: 3 Column: e

Accounts charged:

426.1	$23,668
426.4	130,749
560	21,701
921	28,987
930.2	855,049
	$1,060,154

Schedule Page: 352 Line No.: 5 Column: e

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C.779. Funding through this statutue supports energy production and research and development of alternative sources of electricity. The projects listed below support the research and development of renewable sources of electricity. Also see page 269, Other Deferred Credits (Account 253).

Research Projects	
University of St. Thomas	$719,072
University of Minnesota-Dairy	249,117
University of Minnesota-VWS	380,991
University of Minnesota-Noise	175,080
University of Minnesota-NRRI Torrefact	926,452
Interphases Solar	279,321
University of Minnesota-Gasification	328,287
Minnesota West Community & Technical College	2,050,000
Barr Engineering	65,910
	$5,174,230

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	188,740,355		
4	Transmission	15,407,929		
5	Regional Market	272,848		
6	Distribution	34,431,795		
7	Customer Accounts	12,950,181		
8	Customer Service and Informational	1,224,078		
9	Sales	23		
10	Administrative and General	81,995,983		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	335,023,192		
12	Maintenance			
13	Production	69,046,459		
14	Transmission	3,171,000		
15	Regional Market			
16	Distribution	25,068,285		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	97,285,744		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	257,786,814		
21	Transmission (Enter Total of lines 4 and 14)	18,578,929		
22	Regional Market (Enter Total of Lines 5 and 15)	272,848		
23	Distribution (Enter Total of lines 6 and 16)	59,500,080		
24	Customer Accounts (Transcribe from line 7)	12,950,181		
25	Customer Service and Informational (Transcribe from line 8)	1,224,078		
26	Sales (Transcribe from line 9)	23		
27	Administrative and General (Enter Total of lines 10 and 17)	81,995,983		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	432,308,936	10,867,920	443,176,856
29	Gas			
30	Operation			
31	Production-Manufactured Gas	261,456		
32	Production-Nat. Gas (Including Expl. and Dev.)	115,984		
33	Other Gas Supply	171,440		
34	Storage, LNG Terminaling and Processing	1,646,664		
35	Transmission	608,419		
36	Distribution	16,948,508		
37	Customer Accounts	3,137,364		
38	Customer Service and Informational	510,249		
39	Sales	6		
40	Administrative and General	7,162,390		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	30,562,480		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	367,484		
47	Transmission	17,882		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	5,951,829		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	6,337,195		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	261,456		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	115,984		
54	Other Gas Supply (Enter Total of lines 33 and 45)	171,440		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	2,014,148		
56	Transmission (Lines 35 and 47)	626,301		
57	Distribution (Lines 36 and 48)	22,900,337		
58	Customer Accounts (Line 37)	3,137,364		
59	Customer Service and Informational (Line 38)	510,249		
60	Sales (Line 39)	6		
61	Administrative and General (Lines 40 and 49)	7,162,390		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	36,899,675	1,324,685	38,224,360
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	469,208,611	12,192,605	481,401,216
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	105,462,282	39,451,921	144,914,203
69	Gas Plant	9,337,129	8,019,169	17,356,298
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	114,799,411	47,471,090	162,270,501
72	Plant Removal (By Utility Departments)			
73	Electric Plant	7,128,692	2,543,971	9,672,663
74	Gas Plant	273,898	517,099	790,997
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	7,402,590	3,061,070	10,463,660
77	Other Accounts (Specify, provide details in footnote):			
78	Regulatory Assets (Account No. 182.3)	7,964,226	447,039	8,411,265
79	Preliminary Survey and Investigation (Account No. 183)	359,519	125	359,644
80	Miscellaneous Deferred Debits (Account No. 186)	153	3,368	3,521
81	Miscellaneous Deferred Credits (Account No. 253)	1,187	948	2,135
82	Regulatory Liabilities (Account No. 254)	154,179	3,728	157,907
83	Nonutility (Account Nos. 416-417.1)	1,005,093	19,699	1,024,792
84	Misc Income and Deductions (Account Nos. 426.1-426.5)	141,104	5,477	146,581
85	Nonutility CWP and RWP	13,440		13,440
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	9,638,901	480,384	10,119,285
96	TOTAL SALARIES AND WAGES	601,049,513	63,205,149	664,254,662

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.

Instruction 1:

Account		Allocated to Utility Departments Electric	Gas	Cost at Dec. 31, 2018
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)				
301	Organization	$89,843	$10,765	$100,608
303	Computer Software	386,305,940	46,287,498	432,593,438
	Total intangible plant	$386,395,783	$46,298,263	$432,694,046
389	Land and land rights	$5,698,354	$498,554	$6,196,908
390	Structures and improvements	183,886,920	16,088,416	199,975,336
391	Office furniture and equipment	124,473,304	10,890,270	135,363,574
392	Transportation equipment	9,627,944	1,844,784	11,472,728
393	Stores equipment	226,358	19,804	246,162
394	Tools/shop/garage equipment	4,534,277	396,707	4,930,984
395	Laboratory equipment	-	-	-
396	Power operated equipment	552,870	106,117	658,987
397	Communications equipment	207,560	18,159	225,719
398	Miscellaneous equipment	216,653	18,955	235,608
399.1	Asset retirement costs for general plant	598,106	52,329	650,435
	TOTAL	$716,418,129	$76,232,358	$792,650,487
COMMON UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)				
389	Land and Land Rights	$ -	$ -	$ -
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS (ACCOUNT 107)				
	General Plant	$ 50,372,651	$5,192,183	$ 55,564,834

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.

Instruction 2:

COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNTS 108 AND 111)

General Plant	$282,096,320	$31,241,531	$313,337,851

Common utility plant and accumulated provision for depreciation has been allocated to the various utilities on the basis of customers, employee labor, or direct assignment based on actual use.

	"Non-Legal" ARO Balances
Common General	$(6,809,407)
Common Intangible	-
Total Common	$(6,809,407)

Instruction 3:

COMMON UTILITY PLANT EXPENSES

		Electric	Gas	Total
403	Depreciation Expense	$23,431,868	$1,934,819	$25,366,687
403.1	Depreciation Expense - ARC	11,300	973	12,273
404	Amortization of limited term plant	36,947,689	4,011,792	40,959,481
405	Amortization of other plant	107,216	8,784	116,000
407.4	Amortization of regulatory credits	(37,461)	(3,226)	(40,687)
411.1	Accretion expense	26,161	2,253	28,414
	TOTAL	$60,486,773	$5,955,395	$66,442,168

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.

Basis of allocation of Common Utility Plant expenses:

From	Through	Allocation Methods
403	403	Depreciation allocator (excluding integrated software)
404	404	Software amortization allocator
405	405	Depreciation allocator (excluding integrated software)
407.4	407.4	3-factor (operating revenue, plant in service, supervised O&M)
411.1	411.1	3-factor (operating revenue, plant in service, supervised O&M)

Common Utility Plant and Accumulated Provision for Depreciation and Amortization. The Form 1 reports common utility plant and accumulated provision for depreciation and amortization allocated to the electric department at the end of the year. The Company uses a 13-month average calculation for the electric department common utility plant and accumulated provision for depreciation and amortization in the formula.

Common plant operation and maintenance charges and rents are not separately accounted for and, therefore, are not available.

Instruction 4: The use of common utility plant classification was recommended by Federal Power Commission letter dated Aug. 14, 1969.

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	MISO				
8	Net Purchases (Account 555)	13,389,445	30,757,991	50,253,570	66,875,179
9	Net Sales (Account 447)	(30,706,475)	(55,902,178)	(103,294,318)	(123,906,707)
10	Transmission Rights	(1,851,117)	(5,717,678)	(10,571,411)	(12,158,888)
11	Ancillary Services	218,942	443,531	600,526	820,219
12	Other Items (list separately)				
13	Admin Fees	2,277,533	4,909,072	7,277,077	10,152,538
14	Net Purchases for Storage Operations	23,506	23,506	70,605	120,352
15	ERCOT				
16	Net Purchases (Account 555)	(49,020)	140,040	227,150	192,313
17	Net Sales (Account 447)				
18	Transmission Rights				
19	Ancillary Services				
20	Other Items				
21	Uplift Charges	142	179	183	286
22	NEISO				
23	Net Purchases (Account 555)				
24	Net Sales (Account 447)				
25	Ancillary Services				
26	Other Items				
27	Admin Fees	2,216	5,780	10,797	16,162
28	Uplift Charges				
29	NYISO				
30	Net Purchases (Account 555)				
31	Transmission Rights				
32	Admin Fees	(732)	(732)	(732)	(732)
33	PJM				
34	Net Purchases (Account 555)	64,201	2,050,379	8,998,410	15,600,299
35	Net Sales (Account 447)				
36	Transmission Rights	(35,440)	(87,212)	(282,794)	(431,439)
37	Ancillary Services				
38	Other Items				
39	Admin Fees	3,825	5,695	238,900	183,030
40	Uplift Charges	21,977	949,932	3,516,727	6,378,518
41	SPP				
42	Net Purchases (Account 555)	39,194	118,308	145,367	239,509
43	Transmission Rights		(2,971)	(2,971)	(2,971)
44	Uplift Charges	877	3,513	28,806	43,093
45	Ancillary Services	415	647	959	1,462
46	TOTAL	(16,600,511)	(22,302,198)	(42,783,149)	(35,877,777)

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			7,945,015			920,093
2	Reactive Supply and Voltage			9,942,074			9,253,302
3	Regulation and Frequency Response			1,653,656			3,360,927
4	Energy Imbalance						
5	Operating Reserve - Spinning			1,814,932			2,620,330
6	Operating Reserve - Supplement			439,048			392,577
7	Other						122,137
8	Total (Lines 1 thru 7)			21,794,725			16,669,366

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

Lines 1-7: Number of units not available

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

Lines 1-7: Volume of units not available

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

NSPM MISO NSPP RT_RC_AMT	18,479
NSPM MISO NSPP DA_RC_AMT	103,658
	122,137

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Northern States Power Co. Integrated System

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	7,684	2	18	6,351	1,671				
2	February	7,332	5	19	6,058	1,601				
3	March	6,768	5	12	5,630	1,408				
4	Total for Quarter 1				18,039	4,680				
5	April	6,572	6	11	5,476	1,376				
6	May	9,664	29	14	8,010	1,976				
7	June	10,411	29	17	8,711	1,992				
8	Total for Quarter 2				22,197	5,344				
9	July	10,347	12	17	8,624	2,075				
10	August	9,960	13	18	8,319	1,983				
11	September	8,925	15	17	7,366	1,848				
12	Total for Quarter 3				24,309	5,906				
13	October	6,647	3	14	5,542	1,347				
14	November	7,032	26	18	5,837	1,482				
15	December	7,171	10	18	5,944	1,544				
16	Total for Quarter 4				17,323	4,373				
17	Total Year to Date/Year				81,868	20,303				

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

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin, (collectively, the "NSP Companies"). The construction, operation and maintenance of the two companies' systems is coordinated.

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

"Firm Network Service - For Self" includes load in the Otter Tail Power Balancing Authority (OTP BA). The NSP Companies' load in the OTP BA at the OTP coincident peak is:

(a)	(e)
January	353
February	342
March	284
April	294
May	338
June	310
July	373
August	358
September	304
October	257
November	302
December	332
Total	3,847

"Firm Network Service - For Self" does not include the NSP Companies' load on transmission assets in the Great River Energy Balancing Authority (GRE BA). The NSP Companies' load in the GRE BA at the Great River Energy coincident peak is:

(a)	(e)
January	70
February	64
March	49
April	50
May	66
June	56
July	69
August	55
September	42
October	50
November	60
December	58
Total	689

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	34,908,071
3	Steam	13,245,384			
4	Nuclear	14,601,329	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,367,949
5	Hydro-Conventional	61,187			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,656,805
7	Other	9,192,727			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	380
9	Net Generation (Enter Total of lines 3 through 8)	37,100,627	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	52,248
10	Purchases	12,972,506	27	Total Energy Losses	1,087,680
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	50,073,133
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	50,073,133			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Northern States Power Co. Integrated System

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	4,599,895	819,961	5,393	2	1800
30	February	3,792,321	536,094	5,208	5	1900
31	March	4,027,971	643,148	4,713	5	1900
32	April	3,678,629	488,941	4,695	6	1100
33	May	3,780,198	456,467	6,981	29	1400
34	June	4,331,901	720,693	7,609	29	1700
35	July	5,455,922	789,476	7,534	12	1700
36	August	3,937,455	490,468	7,244	13	1800
37	September	4,176,404	712,734	6,385	15	1700
38	October	4,019,421	482,088	4,801	3	1400
39	November	4,077,597	787,701	5,013	26	1800
40	December	4,195,419	729,034	5,022	10	1800
41	TOTAL	50,073,133	7,656,805			

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

MWH stored in Wind2Battery project on Dec. 31, 2018 0.802

Schedule Page: 401 Line No.: 29 Column: Sys

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin. The construction, operation and maintenance of the two companies' systems is coordinated. This table shows the integrated system peak and the demand of each jurisdiction at the time of the integrated system peak. The monthly peaks reported in column d of page 401b are the sums of the monthly peaks for the states of Minnesota, North Dakota and South Dakota shown below.

			Northern States Power Co. (a Minnesota corporation)			Northern States Power Co. (a Wisconsin corporation)	
Day	Hour	Integrated System	Minnesota	North Dakota	South Dakota	Wisconsin	Michigan
2-Jan	1800	6,536	4,682	382	329	1,117	26
5-Feb	1900	6,267	4,500	383	325	1,033	26
5-Mar	1900	5,717	4,109	306	298	984	20
6-Apr	1100	5,675	4,065	336	294	958	22
29-May	1400	8,246	6,229	365	387	1,241	24
29-Jun	1700	8,944	6,796	335	478	1,312	23
12-Jul	1700	8,835	6,644	373	517	1,279	22
13-Aug	1800	8,527	6,401	381	462	1,260	23
15-Sep	1700	7,500	5,679	275	431	1,095	20
3-Oct	1400	5,738	4,214	277	310	918	19
26-Nov	1800	6,058	4,349	354	310	1,023	22
10-Dec	1800	6,104	4,387	329	306	1,058	24

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

Line No.	Item (a)	Plant Name: *Riverside* (b)	Plant Name: *Wilmarth* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1911	1948
4	Year Last Unit was Installed	2009	1951
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	585.90	25.00
6	Net Peak Demand on Plant - MW (60 minutes)	512	19
7	Plant Hours Connected to Load	6329	7967
8	Net Continuous Plant Capability (Megawatts)	500	18
9	When Not Limited by Condenser Water	500	18
10	When Limited by Condenser Water	454	18
11	Average Number of Employees	19	27
12	Net Generation, Exclusive of Plant Use - KWh	2633272160	100305883
13	Cost of Plant: Land and Land Rights	450133	499773
14	Structures and Improvements	52424815	11107836
15	Equipment Costs	256355881	50341397
16	Asset Retirement Costs	860791	785153
17	Total Cost	310091620	62734159
18	Cost per KW of Installed Capacity (line 17/5) Including	529.2569	2509.3664
19	Production Expenses: Oper, Supv, & Engr	612820	411796
20	Fuel	75130301	571435
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	152001	2113369
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1960679	29212
26	Misc Steam (or Nuclear) Power Expenses	983460	666145
27	Rents	683106	332668
28	Allowances	0	0
29	Maintenance Supervision and Engineering	573428	57629
30	Maintenance of Structures	1144402	249968
31	Maintenance of Boiler (or reactor) Plant	0	1681468
32	Maintenance of Electric Plant	3218028	202599
33	Maintenance of Misc Steam (or Nuclear) Plant	285983	616733
34	Total Production Expenses	84744208	6933022
35	Expenses per Net KWh	0.0322	0.0691

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas	Oil	RDF	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF	Barrels	Tons	MCF	
38	Quantity (Units) of Fuel Burned	0	17473748	8	168042	48645	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1081	137757	5689	1068	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	4.301	2141.437	2.138	4.092	0.000
41	Average Cost of Fuel per Unit Burned	0.000	4.301	2141.437	13.664	4.092	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	3.979	379.567	1.201	3.831	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.029	0.000	0.000	0.010	0.000
44	Average BTU per KWh Net Generation	0.000	7172.020	0.000	0.000	10637.480	0.000

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

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

Line No.	Item (a)	Plant Name: *Sherburne County* (b)	Plant Name: *Granite City* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Ind Enclosures
3	Year Originally Constructed	1976	1969
4	Year Last Unit was Installed	1987	1969
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2469.32	72.00
6	Net Peak Demand on Plant - MW (60 minutes)	1890	12
7	Plant Hours Connected to Load	8760	8
8	Net Continuous Plant Capability (Megawatts)	1879	64
9	When Not Limited by Condenser Water	1879	64
10	When Limited by Condenser Water	1879	52
11	Average Number of Employees	215	0
12	Net Generation, Exclusive of Plant Use - KWh	10325500371	-536000
13	Cost of Plant: Land and Land Rights	5951721	40240
14	Structures and Improvements	228475576	1241718
15	Equipment Costs	1244000049	7528833
16	Asset Retirement Costs	-3949845	63539
17	Total Cost	1474477501	8874330
18	Cost per KW of Installed Capacity (line 17/5) Including	597.1188	123.2546
19	Production Expenses: Oper, Supv, & Engr	2085521	-65
20	Fuel	257369385	25557
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	13904113	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	3513955	625
26	Misc Steam (or Nuclear) Power Expenses	11228430	678881
27	Rents	2259665	2490
28	Allowances	0	0
29	Maintenance Supervision and Engineering	1612649	-13
30	Maintenance of Structures	2285508	40202
31	Maintenance of Boiler (or reactor) Plant	15976825	0
32	Maintenance of Electric Plant	4074048	22783
33	Maintenance of Misc Steam (or Nuclear) Plant	7582575	-1
34	Total Production Expenses	321892674	770459
35	Expenses per Net KWh	0.0312	-1.4374

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Oil	Gas		Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons		Barrels	MCF		Barrels
38	Quantity (Units) of Fuel Burned	6159611	0	19745	4573	0	71
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8824	0	138243	1087	0	138982
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.534	0.000	91.882	4.554	0.000	66.555
41	Average Cost of Fuel per Unit Burned	41.045	0.000	91.882	4.554	0.000	66.555
42	Average Cost of Fuel Burned per Million BTU	2.326	0.000	15.825	4.190	0.000	11.402
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.020	0.000	0.000	-0.050	0.000
44	Average BTU per KWh Net Generation	0.000	10546.110	0.000	0.000	-9935.060	0.000

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

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

Line No.	Item (a)	Plant Name: *Angus Anson* (b)	Plant Name: *Black Dog 2, 5, & 6* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbines	CC / Gas Turb
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Conventional
3	Year Originally Constructed	1994	1987
4	Year Last Unit was Installed	2005	2018
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	405.66	554.29
6	Net Peak Demand on Plant - MW (60 minutes)	340	509
7	Plant Hours Connected to Load	1402	3803
8	Net Continuous Plant Capability (Megawatts)	386	526
9	When Not Limited by Condenser Water	386	526
10	When Limited by Condenser Water	327	494
11	Average Number of Employees	8	26
12	Net Generation, Exclusive of Plant Use - KWh	120297405	984969144
13	Cost of Plant: Land and Land Rights	1155577	952692
14	Structures and Improvements	7721804	55181473
15	Equipment Costs	115407464	291033543
16	Asset Retirement Costs	652565	48341
17	Total Cost	124937410	347216049
18	Cost per KW of Installed Capacity (line 17/5) Including	307.9855	626.4159
19	Production Expenses: Oper, Supv, & Engr	81597	366260
20	Fuel	4786448	27083450
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	217810
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	6442	1947997
26	Misc Steam (or Nuclear) Power Expenses	545849	444462
27	Rents	33535	495440
28	Allowances	0	0
29	Maintenance Supervision and Engineering	2972	413584
30	Maintenance of Structures	148364	1938448
31	Maintenance of Boiler (or reactor) Plant	0	154325
32	Maintenance of Electric Plant	472808	876501
33	Maintenance of Misc Steam (or Nuclear) Plant	296	604478
34	Total Production Expenses	6078311	34542755
35	Expenses per Net KWh	0.0505	0.0351

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas		Oil		Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF		Barrels		MCF	
38	Quantity (Units) of Fuel Burned	1325454	0	2553	0	7192690	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1071	0	137809	0	1073	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.476	0.000	70.358	0.000	3.765	0.000
41	Average Cost of Fuel per Unit Burned	3.476	0.000	70.358	0.000	3.765	0.000
42	Average Cost of Fuel Burned per Million BTU	3.244	0.000	12.156	0.000	3.509	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.040	0.000	0.000	0.030	0.000
44	Average BTU per KWh Net Generation	0.000	11928.090	0.000	0.000	7870.320	0.000

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

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *A S King* (d)			Plant Name: *Prairie Island* (e)			Plant Name: *Blue Lake* (f)			Line No.
Steam			Nuclear			Gas Turbine			1
Conventional			Conventional			Ind Enclosures			2
1968			1973			1974			3
1968			1974			2005			4
598.40			1186.20			559.32			5
531			1122			361			6
6188			8760			588			7
511			1092			545			8
511			1092			545			9
511			1040			453			10
82			559			5			11
2698695700			8983305000			105029000			12
1335100			969281			141878			13
39916358			324061645			1712629			14
672545674			1889444784			94949685			15
3706538			-139278542			87368			16
717503670			2075197168			96891560			17
1199.0369			1749.4496			173.2310			18
647797			34709322			103485			19
64032271			75699013			5298805			20
0			5066176			0			21
7272664			27829577			0			22
0			0			0			23
0			0			0			24
117992			2748220			172519			25
3098424			71520409			186791			26
1360874			7715923			80039			27
0			0			0			28
1772783			2845177			25779			29
1824737			142945			148655			30
7186352			22656613			0			31
5269129			6282469			551071			32
2046356			20593532			24736			33
94629379			277809376			6591880			34
0.0351			0.0309			0.0628			35
Coal	Gas	Oil		Nuclear		Gas		Oil	36
Tons	MCF	Barrels		Grams U-235		MCF		Barrels	37
1504831	53400	44	0	849683	0	1049313	0	2709	38
8959	1077	138378	0	111007	0	1077	0	138927	39
39.046	4.165	134.279	0.000	0.000	0.000	4.830	0.000	84.965	40
42.456	4.165	134.279	0.000	0.000	0.000	4.830	0.000	84.965	41
2.369	3.869	23.104	0.000	0.808	0.000	4.484	0.000	14.561	42
0.000	0.020	0.000	0.000	0.010	0.000	0.000	0.050	0.000	43
0.000	10012.750	0.000	0.000	10487.310	0.000	0.000	10912.760	0.000	44

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Inver Hills* (d)	Plant Name: *High Bridge 7, 8, 9* (e)	Plant Name: *Monticello* (f)	Line No.
Gas Turbine	Combined Cycle	Nuclear	1
Ind Enclosures	Conventional	Conventional	2
1972	1924	1971	3
1972	2008	1971	4
280.50	644.06	684.97	5
272	624	687	6
321	5236	8691	7
371	606	646	8
371	606	646	9
282	530	617	10
7	23	433	11
14143295	2333082000	5618024000	12
351801	528150	783302	13
1616403	70958498	245679843	14
55915679	324970870	1255130236	15
23827	17870	132475222	16
57907710	396475388	1634068603	17
206.4446	615.5877	2385.6061	18
54845	459975	23488610	19
1485498	63113134	46189505	20
0	0	3819542	21
0	0	21799672	22
0	0	0	23
0	0	0	24
276963	2149314	76051	25
59707	807458	56968199	26
73287	581045	5373782	27
0	0	0	28
349	767107	2199775	29
328895	1576532	0	30
0	0	18086976	31
620086	6864169	3504920	32
4950	131988	11450023	33
2904580	76450722	192957055	34
0.2054	0.0328	0.0343	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	Gas	Oil		Gas			Nuclear		36
	MCF	Barrels		MCF			Grams U-235		37
0	247424	3809	0	16834839	0	0	474307	0	38
0	1082	139995	0	951	0	0	124409	0	39
0.000	4.134	121.488	0.000	3.749	0.000	0.000	0.000	0.000	40
0.000	4.134	121.488	0.000	3.749	0.000	0.000	0.000	0.000	41
0.000	3.822	20.662	0.000	3.944	0.000	0.000	0.787	0.000	42
0.000	0.110	0.000	0.000	0.030	0.000	0.000	0.010	0.000	43
0.000	20504.090	0.000	0.000	6863.280	0.000	0.000	10504.580	0.000	44

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Black Dog 3 & 4* (d)	Plant Name: *Key City* (e)	Plant Name: *Benson* (f)	Line No.
Steam	Gas Turbine	Steam	1
Conventional	Ind Enclosures	Conventional	2
1952	1970	2007	3
1960	1970	2007	4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	67495	0	13
0	1002265	0	14
0	7597648	0	15
0	0	0	16
0	8667408	0	17
0	0	0	18
0	0	0	19
293	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
4148	25	0	25
0	0	0	26
1773	768	0	27
0	0	0	28
736	0	0	29
0	1845	0	30
707	0	0	31
5960	7185	0	32
4076	0	0	33
17693	9823	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
						RDF		Wood	36
						Tons		Tons	37
0	0	0	0	0	0	6471	0	13799	38
0	0	0	0	0	0	5633	0	6009	39
0.000	0.000	0.000	0.000	0.000	0.000	51.784	0.000	66.145	40
0.000	0.000	0.000	0.000	0.000	0.000	103.568	0.000	132.291	41
0.000	0.000	0.000	0.000	0.000	0.000	4.596	0.000	5.504	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.080	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	16122.240	0.000	44

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

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

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: -1 Column: e

Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403)

(a) Operating and maintenance costs of the Prairie Island Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 47 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.

Schedule Page: 402.1 Line No.: -1 Column: b

Sherburne County Generating Plant Unit 3 is jointly owned by NSP-Minnesota (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). See Note 4 of the Financial Statements on Page 123 for disclosures regarding Sherco Unit 3.

Schedule Page: 403.1 Line No.: -1 Column: f

Instruction 12 - Monticello Nuclear Generating Plant (p. 403.1)

(a) Operating and maintenance costs of the Monticello Plant are expensed as incurred. NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric cases.

(b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.

(c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 84 metric tons of uranium metal with a nominal U-235 enrichment of 3.8 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.

Schedule Page: 403.2 Line No.: -1 Column: f

On June 29, 2018 NSP-Minnesota acquired the Benson Power Facility. For additional information, see page 108 item 3.

Schedule Page: 402.2 Line No.: 1 Column: c

Black Dog Unit 2 & 5 are combined cycle plants. Black Dog Unit 6 is a gas turbine.

Schedule Page: 402 Line No.: 39 Column: e2

Average heat content of fuel burned is MBTU/kg U235.

Schedule Page: 402.1 Line No.: 39 Column: b1

The "Average Heat Content of Fuel Burned" is calculated as:

Coal: Btu/pound
Oil: Btu/ gallons
Gas: Btu/cubic ft

Schedule Page: 402.1 Line No.: 39 Column: f2

Average heat content of fuel burned is in MBTU/kg U235.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Henn Is & Upper Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	run of river	
2	Plant Construction type (Conventional or Outdoor)	conventional	
3	Year Originally Constructed	1908	
4	Year Last Unit was Installed	1955	
5	Total installed cap (Gen name plate Rating in MW)	13.89	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	13	0
7	Plant Hours Connect to Load	8,323	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	7	0
10	(b) Under the Most Adverse Oper Conditions	6	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - Kwh	61,187,191	0
13	Cost of Plant		
14	Land and Land Rights	1,548,707	0
15	Structures and Improvements	1,350,556	0
16	Reservoirs, Dams, and Waterways	8,889,667	0
17	Equipment Costs	13,473,537	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	25,262,467	0
21	Cost per KW of Installed Capacity (line 20 / 5)	1,818.7521	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	31,859	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	369,350	0
27	Misc Hydraulic Power Generation Expenses	449,236	0
28	Rents	50,140	0
29	Maintenance Supervision and Engineering	8,644	0
30	Maintenance of Structures	37,215	0
31	Maintenance of Reservoirs, Dams, and Waterways	207,434	0
32	Maintenance of Electric Plant	107,266	0
33	Maintenance of Misc Hydraulic Plant	1,397	0
34	Total Production Expenses (total 23 thru 33)	1,262,541	0
35	Expenses per net KWh	0.0206	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	STEAM PLANT					
2						
3	Red Wing	1949	20.00	24.0	120,881,765	69,479,686
4	Minnesota Valley	1932				20,404
5	High Bridge 5 & 6	1924				
6						
7						
8	GAS PLANT					
9						
10	West Faribault	1965				
11						
12						
13	INTERNAL COMBUSTION					
14						
15	Dispersed Generation					2,031,625
16						
17						
18	WIND TURBINE					
19						
20	Lake Benton	1997				10,190,362
21	Grand Meadow Wind Farm	2008	100.50	104.0	270,861,410	220,200,845
22	Nobles Wind	2010	201.00	201.0	651,204,150	538,573,449
23	Borders Wind	2015	150.00	147.1	609,517,146	278,144,523
24	Pleasant Valley Wind	2015	200.00	195.0	756,650,319	353,508,516
25	Courtenay Wind	2016	200.00	192.4	714,237,317	299,674,848
26						
27	SOLAR					
28						
29	Photovoltaic Units	1995				
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
3,473,984	2,401,164	488,055	3,093,835	RDF, Gas	111	3
	440		16,492			4
	25,099		196,143			5
						6
						7
						8
						9
						10
						11
						12
						13
						14
				Oil		15
						16
						17
						18
						19
				Wind		20
2,191,053	1,207,110		2,017,273	Wind		21
2,679,470	2,662,091		1,466,159	Wind		22
1,854,297	2,083,238		1,316,907	Wind		23
1,767,543	3,158,191		1,792,155	Wind		24
1,498,374	2,987,694		1,992,576	Wind		25
						26
						27
						28
				Solar		29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Schedule Page: 410 Line No.: 1 Column: g

The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	(5703;01) CHISAGO CO.	FORBES	500.00	500.00	TOWER	61.45		1
2	(5702;01) FORBES	RIEL (MH)	500.00	500.00	TOWER	203.77		1
3	(0998;01) SIOUX CITY	SPLIT ROCK	345.00	345.00	SINGLE POLE		4.43	1
4			345.00	345.00	SINGLE POLE		0.63	1
5	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.00	345.00	SINGLE POLE	4.91	0.24	1
6	(0996;01) DICKINSON SW	PARKERS LAKE	345.00	345.00	TOWER	0.15	9.60	1
7	(0994;01) ALLEN S KING	CHISAGO CO.	345.00	345.00	SINGLE POLE		31.56	1
8			345.00	345.00	TOWER		6.62	1
9	(0992;02) COON CREEK	SHERBURNE CO.	345.00	345.00	K-FRAME	16.92	0.37	1
10			345.00	345.00	SINGLE POLE		14.66	1
11			345.00	345.00	TOWER		11.43	1
12	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.00	345.00	TOWER		5.81	1
13	(0989;01) BLUE LAKE	INVER HILLS	345.00	345.00	K-FRAME	0.78		1
14			345.00	345.00	SINGLE POLE		1.03	1
15			345.00	345.00	TOWER	3.52	16.95	1
16	(0989;01) INVER HILLS	RED ROCK	345.00	345.00	H-FRAME	0.52		1
17			345.00	345.00	K-FRAME	2.00		1
18			345.00	345.00	TOWER	5.98		1
19	(0988;01) BLUE LAKE	PARKERS LAKE	345.00	345.00	SINGLE POLE		2.18	1
20			345.00	345.00	TOWER		12.61	1
21	(0987;01) PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	20.82	0.20	1
22			345.00	345.00	SINGLE POLE		6.28	1
23			345.00	345.00	TOWER		2.15	1
24			345.00	345.00	TOWER		2.51	1
25	(0986;02) PRAIRIE ISLAND	RED ROCK	345.00	345.00	K-FRAME	20.99		1
26			345.00	345.00	SINGLE POLE	6.28		1
27			345.00	345.00	TOWER	2.15		1
28			345.00	345.00	TOWER		2.52	1
29	(0985;01) COON CREEK	SHERBURNE CO.	345.00	345.00	H-FRAME	16.13	1.25	1
30			345.00	345.00	K-FRAME	3.37		1
31			345.00	345.00	SINGLE POLE	0.29	0.63	1
32			345.00	345.00	TOWER	5.79	5.67	1
33	(0984;03) COON CREEK	SHERBURNE CO.	345.00	345.00	K-FRAME	18.75		1
34			345.00	345.00	SINGLE POLE	15.13		1
35			345.00	345.00	TOWER	9.57		1
36					TOTAL	5,126.15	605.87	152

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(0984;01) COON CREEK	TERMINAL	345.00	345.00	SINGLE POLE		4.49	1
2			345.00	345.00	TOWER		9.14	1
3	(0982;01) BLUE LAKE	SCOTT CO.	345.00	345.00	TOWER	8.15		1
4	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.00	345.00	K-FRAME	1.86		1
5			345.00	345.00	SINGLE POLE	0.34		1
6	(0982;01) CRANDALL	WILMARTH	345.00	345.00	K-FRAME	51.13		1
7			345.00	345.00	TOWER	1.24		1
8	(0982;01) HELENA	SCOTT CO.	345.00	345.00	K-FRAME	15.01		1
9			345.00	345.00	TOWER	2.16		1
10	(0982;01) HELENA	SHEAS LAKE	345.00	345.00	K-FRAME	7.45		1
11	(0982;01) LAKEFIELD JCT	LAKEFIELD GENERATING	345.00	345.00	K-FRAME	18.37		1
12			345.00	345.00	SINGLE POLE	0.34		1
13	(0982;01) SHEAS LAKE	WILMARTH	345.00	345.00	K-FRAME	23.37		1
14			345.00	345.00	TOWER	1.36		1
15	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.00	345.00	K-FRAME	3.69		1
16			345.00	345.00	TOWER	0.72	15.19	1
17	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.00	345.00	SINGLE POLE	31.38	0.55	1
18			345.00	345.00	TOWER		5.68	1
19	(0980;01) COON CREEK	KOHLMAN LAKE	345.00	345.00	SINGLE POLE	4.49	2.94	1
20			345.00	345.00	TOWER	6.99	5.50	1
21	(0979;01) ADAMS	PLEASANT VALLEY (GRE)	345.00	345.00	K-FRAME	16.83		1
22	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.00	345.00	K-FRAME	13.54		1
23	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.00	345.00	H-FRAME	1.14		1
24			345.00	345.00	K-FRAME	15.15		1
25	(0979;01) NORTH	PRAIRIE ISLAND	345.00	345.00	H-FRAME	1.08		1
26			345.00	345.00	K-FRAME	26.15		1
27			345.00	345.00	TOWER	2.40		1
28	(0978;01) ELM CREEK	MONTICELLO SUB	345.00	345.00	H-FRAME	17.22		1
29			345.00	345.00	K-FRAME	3.37		1
30			345.00	345.00	TOWER	5.51		1
31	(0978;01) ELM CREEK	PARKERS LAKE	345.00	345.00	SINGLE POLE	0.59		1
32			345.00	345.00	TOWER	10.46		1
33	(0977;01) ALLEN S KING	KOHLMAN LAKE	345.00	345.00	TOWER	12.67		1
34	(0977;01) KOHLMAN LAKE	TERMINAL	345.00	345.00	SINGLE POLE	2.94		1
35			345.00	345.00	TOWER	7.20		1
36					TOTAL	5,126.15	605.87	152

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.00	345.00	SINGLE POLE	3.68		1
2			345.00	345.00	TOWER	1.86		1
3	(0976;01) BLUE LAKE	HAMPTON	345.00	345.00	K-FRAME	2.38		1
4			345.00	345.00	K-FRAME	6.01		1
5			345.00	345.00	SINGLE POLE	1.03		1
6			345.00	345.00	TOWER	23.61		1
7	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.00	345.00	TOWER	9.47		1
8	(0976;01) HAMPTON	PRAIRIE ISLAND	345.00	345.00	K-FRAME	16.00		1
9			345.00	345.00	TOWER	3.55		1
10	(0975;01) ALLEN S KING	RED ROCK	345.00	345.00	K-FRAME	5.47		1
11			345.00	345.00	TOWER	19.90		1
12	(0974;01) MANKATO	WILMARTH	345.00	345.00	SINGLE POLE	0.22		1
13	(0973;01) MONTICELLO SUB	QUARRY	345.00	345.00	SINGLE POLE	30.04		1
14	(0972-MN;01) BROOKINGS	HAWKS NEST LAKE	345.00	345.00	SINGLE POLE	18.58		1
15	(0972-SD;01) BROOKINGS	HAWKS NEST LAKE	345.00	345.00	SINGLE POLE	10.31		1
16	(0972;01) HAWKS NEST	LYON CO.	345.00	345.00	SINGLE POLE	30.55		1
17	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.00	345.00	SINGLE POLE	0.42		1
18	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.00	345.00	SINGLE POLE	0.38		1
19	(0966;01) BROOKINGS CO.	BIG STONE SOUTH	345.00	345.00	SINGLE POLE	71.58		1
20	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.00	345.00	2 POLE	3.12		1
21			345.00	345.00	SINGLE POLE	40.07		1
22	(0964;01) HAMPTON	NORTH ROCHESTER	345.00	345.00	SINGLE POLE	37.85		1
23	(0962;01) HAZEL CREEK	LYON CO.	345.00	345.00	SINGLE POLE	24.54		1
24	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.00	345.00	SINGLE POLE	18.10		1
25	(0960;01) CHUB LAKE (GRE)	HELENA	345.00	345.00	SINGLE POLE	20.87		1
26	(0959;02) CEDAR MTN.	HELENA	345.00	345.00	SINGLE POLE		73.06	1
27	(0958;01) CEDAR MTN.	HELENA	345.00	345.00	SINGLE POLE	73.10		1
28	(0957;02) CEDAR MTN.	LYON CO.	345.00	345.00	SINGLE POLE		49.49	1
29	(0956;01) CEDAR MTN.	LYON CO.	345.00	345.00	SINGLE POLE	49.49		1
30	(0955-MN;01) ALEXANDRIA	BISON	345.00	345.00	2 POLE	3.35		1
31			345.00	345.00	SINGLE POLE	100.95		1
32	(0955-ND;01) ALEXANDRIA	BISON	345.00	345.00	SINGLE POLE	34.47		1
33	(0954;01) ALEXANDRIA SW.	QUARRY	345.00	345.00	SINGLE POLE	81.22		1
34	(0953;01) LAKEFIELD JCT	NOBLES CO.	345.00	345.00	SINGLE POLE	22.67		1
35			345.00	345.00	SINGLE POLE	13.27		1
36					TOTAL	5,126.15	605.87	152

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.00	345.00	SINGLE POLE	10.69		1
2			345.00	345.00	SINGLE POLE	31.88		1
3	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.00	345.00	SINGLE POLE	4.43		1
4			345.00	345.00	SINGLE POLE	5.24		1
5	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.00	345.00	SINGLE POLE	4.97		1
6	(0924;01) MCHENRY (GRE)	MAGIC CITY	230.00	230.00	SINGLE POLE	20.57		1
7	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.00	230.00	SINGLE POLE	19.32		1
8	(0922;01) BOSWELL	CASS LAKE (OTP)	230.00	230.00	SINGLE POLE	51.46		1
9	(0920;01) GLENBOROUGH	PEACE GARDEN	230.00	230.00	H-FRAME	1.98		1
10	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.00	230.00	H-FRAME	54.67		1
11	(0919;01) PAYNESVILLE	WILLMAR (GRE)	230.00	230.00	H-FRAME	2.57		1
12			230.00	230.00	SINGLE POLE	27.17		1
13	(0918;01) SIOUX FALLS	SPLIT ROCK	230.00	230.00	SINGLE POLE	0.96		1
14	(0916;01) GRAND FORKS	PRAIRIE	230.00	230.00	H-FRAME	6.35		1
15			230.00	230.00	SINGLE POLE	0.48		1
16	(0915;01) FARGO (WAPA)	SHEYENNE	230.00	230.00	H-FRAME	4.20	0.05	1
17	(0912;01) DRAYTON	LETELLIER (MANITOBA	230.00	230.00	H-FRAME	28.66		1
18			230.00	230.00	SINGLE POLE	0.07		1
19	(0911;01) AUDUBON (OTP)	SHEYENNE	230.00	230.00	H-FRAME	1.41		1
20	(0911;01) MAPLE RIVER	SHEYENNE	230.00	230.00	H-FRAME	2.82		1
21			230.00	230.00	TOWER	0.16	3.59	1
22	(0910;01) MAPLE RIVER	WAHPETON (MINNKOTA)	230.00	230.00	TOWER	3.59		1
23	(0909;01) AUDUBON (OTP)	HUBBARD (GRE)	230.00	230.00	H-FRAME	37.69		1
24			230.00	230.00	SINGLE POLE	0.87		1
25	(0902,0921;01) ROCK	RUSH CITY (GRE)	230.00	230.00	SINGLE POLE	11.16		1
26			230.00	230.00	SINGLE POLE	53.91		1
27			230.00	230.00	TOWER	2.61		1
28	(0902;01) BEAR CREEK	ROCK CREEK	230.00	230.00	SINGLE POLE	12.55		1
29	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.00	230.00	H-FRAME	1.35		1
30			230.00	230.00	SINGLE POLE	0.96		1
31			230.00	230.00	TOWER	44.15		1
32	(0900;02) GRANITE FALLS	PANTHER (GRE)	230.00	230.00	K-FRAME	0.18		1
33			230.00	230.00	TOWER	32.66		1
34	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.00	230.00	TOWER	28.45		1
35	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	15.51		1
36					TOTAL	5,126.15	605.87	152

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Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.00	161.00	SINGLE POLE	11.41		1
2			161.00	161.00	SINGLE POLE	0.44	15.82	1
3	(5306;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	161.00	161.00	SINGLE POLE	16.60		1
4	(5305-MN;01) LAWRENCE	ST CROIX FALLS	161.00	161.00	SINGLE POLE	1.57		1
5			161.00	161.00	UNDERGROU	0.58		1
6	(5301;01) ELK (ALLIANT)	ROCK CO.	161.00	161.00	H-FRAME	5.39		1
7	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.00	161.00	H-FRAME	3.44		1
8			161.00	161.00	SINGLE POLE	0.08		1
9	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.00	161.00	H-FRAME	10.35		1
10			161.00	161.00	SINGLE POLE	0.80		1
11	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.00	161.00	H-FRAME	30.11		1
12			161.00	161.00	SINGLE POLE		1.41	1
13								
14	SUMMARY OF 115 KV		115.00	115.00	Overhead	1,447.81	151.58	
15			115.00	115.00	Underground	13.22		
16	SUMMARY OF 69 KV		69.00	69.00	Overhead	1,483.92	96.54	
17			69.00	69.00	Underground	1.53		
18	SUMMARY OF 34.5 KV		34.50	34.50	Overhead	60.93	31.51	
19			34.50	34.50	Underground	0.59		
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,126.15	605.87	152

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
9-1192 ACSR	2,237,403	15,845,813	18,083,217					1
9-1192 ACSR	1,723,645	66,437,687	68,161,333					2
6-954 ACSS		670,200	670,200					3
6-954 ACSS/TW								4
6-954 ACSS/TW	139,860	8,455,822	8,595,682					5
6-954 ACSR		564,837	564,837					6
6-954 ACSR		1,648,291	1,648,291					7
6-795 ACSR								8
6-954 ACSR	472,775	3,834,705	4,307,479					9
6-954 ACSR								10
6-954 ACSR								11
6-954 ACSR		196,978	196,978					12
6-795 ACSR	80,238	1,436,429	1,516,667					13
6-795 ACSR								14
6-795 ACSR								15
6-795 ACSR	272,767	1,672,480	1,945,247					16
6-795 ACSR								17
6-795 ACSR								18
6-795 ACSR		478,209	478,209					19
6-795 ACSR								20
6-795 ACSR		3,014,532	3,014,532					21
6-795 ACSR								22
6-795 ACSR								23
6-954 ACSR								24
6-795 ACSR	661,692	6,976,971	7,638,662					25
6-795 ACSR								26
6-795 ACSR								27
6-954 ACSR								28
6-954 ACSR	17,816	14,647,905	14,665,722					29
6-954 ACSR								30
6-954 ACSR								31
6-954 ACSR								32
6-954 ACSR	506,296	7,477,760	7,984,056					33
6-954 ACSR								34
6-954 ACSR								35
	120,770,039	2,016,652,033	2,137,422,066	577,394	6,692,685	2,889,594	10,159,673	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
6-795 ACSR	160,760	2,309,570	2,470,331					1
6-795 ACSR								2
6-795 ACSR	155,241	3,366,973	3,522,214					3
6-795 ACSR	612,272	9,015,795	9,628,066					4
6-795 ACSR								5
6-795 ACSR		454,390	454,390					6
6-795 ACSR								7
6-795 ACSR		402,416	402,416					8
6-795 ACSR								9
6-795 ACSR	95,480	1,602,336	1,697,816					10
6-795 ACSR	214,005	7,176,301	7,390,306					11
6-795 ACSR								12
6-795 ACSR	271,747	4,692,783	4,964,530					13
6-795 ACSR								14
6-795 ACSR	24,099	872,818	896,916					15
6-795 ACSR								16
6-954 ACSR	4,408,021	10,488,610	14,896,631					17
6-795 ACSR								18
6-795 ACSR	986,693	2,657,526	3,644,219					19
6-795 ACSR								20
6-795 ACSR	41,979	5,206,476	5,248,455					21
6-795 ACSR	35,037	4,307,001	4,342,038					22
6-795 ACSR	43,098	5,272,671	5,315,769					23
6-795 ACSR								24
6-795 ACSR	67,126	8,521,013	8,588,139					25
6-795 ACSR								26
6-954 ACSR								27
6-954 ACSR	868,700	13,866,066	14,734,765					28
6-954 ACSR								29
6-954 ACSR								30
6-954 ACSR	13,498	914,131	927,629					31
6-954 ACSR								32
6-795 ACSR	1,136,939	2,280,784	3,417,723					33
6-795 ACSR	1,136,938	2,189,075	3,326,013					34
6-795 ACSR								35
	120,770,039	2,016,652,033	2,137,422,066	577,394	6,692,685	2,889,594	10,159,673	36

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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.
6-795 ACSR	104,148	593,836	697,984					1
6-795 ACSR								2
6-795 ACSR	873,092	4,578,124	5,451,217					3
6-954 ACSR								4
6-795 ACSR								5
6-795 ACSR								6
6-795 ACSR	45,639	512,475	558,113					7
6-795 ACSR	1,296,677	6,960,661	8,257,338					8
6-795 ACSR								9
6-795 ACSR	401,128	2,691,773	3,092,901					10
6-795 ACSR								11
6-795 ACSR		888,655	888,655					12
6-954 ACSS/TW	4,493,575	10,969,295	15,462,870					13
6-954 ACSS/TW		56,444,432	56,444,432					14
6-954 ACSS/TW	509,810	20,993,906	21,503,715					15
6-954 ACSS/TW								16
6-795 ACSS	13,748	933,240	946,988					17
6-795 ACSS		1,215,849	1,215,849					18
6-556.5 ACSR/T2	3,526,999	57,750,432	61,277,431					19
6-954 ACSS/TW	3,540,809	61,239,201	64,780,010					20
6-954 ACSS/TW								21
6-397.5 TACSRVR2	7,382,749		7,382,749					22
6-954 ACSS/TW	340,384	27,165,962	27,506,346					23
6-954 ACSS/TW	6,152,890	37,681,201	43,834,091					24
6-954 ACSS/TW	5,384,345	36,282,633	41,666,978					25
6-954 ACSS/TW								26
6-954 ACSS/TW	9,144,838	112,135,762	121,280,600					27
6-954 ACSS/TW								28
6-954 ACSS/TW	5,590,789	65,839,990	71,430,778					29
6-954 ACSS/TW	5,771,419	84,705,342	90,476,761					30
6-954 ACSS/TW								31
6-954 ACSS/TW	1,513,232	22,705,097	24,218,329					32
6-954 ACSS/TW	4,188,286	66,051,104	70,239,390					33
6-397.5 ACSR/T2								34
6-954 ACSS/TW								35
	120,770,039	2,016,652,033	2,137,422,066	577,394	6,692,685	2,889,594	10,159,673	36

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
6-397.5 ZTACSR	6,748,721	115,866,909	122,615,630					1
6-954 ACSS/TW								2
6-954 ACSR	944,435	7,561,031	8,505,466					3
6-954 ACSS/TW								4
6-954 ACSS/TW	355,907	9,176,023	9,531,930					5
6-477 ACSR/VR2	709,577	25,902,796	26,612,373					6
3-795 ACSS	884,508	9,194,724	10,079,232					7
3-795 ACSS	1,023,124	23,387,110	24,410,234					8
3-954 ACSR								9
3-954 ACSR	1,288,507	12,521,625	13,810,132					10
3-795 ACSR	302,577	7,615,686	7,918,263					11
3-795 ACSR								12
3-795 ACSS	531,676	605,867	1,137,542					13
3-954 ACSR	24,662	1,532,861	1,557,523					14
3-954 ACSR								15
3-795 ACSR	21,223	806,965	828,188					16
3-954 ACSR	57,281	3,015,006	3,072,287					17
3-954 ACSR								18
3-795 ACSR	10,733	237,425	248,158					19
3-795 ACSR	21,002	597,200	618,203					20
3-795 ACSR								21
3-795 ACSR	55,625	283,964	339,589					22
3-795 ACSR	57,863	7,756,978	7,814,841					23
3-795 ACSR								24
3-1272 ACSR	407,857	6,435,375	6,843,232					25
3-795 ACSR								26
3-1272 ACSR								27
3-795 ACSR	29,881	1,234,702	1,264,583					28
3-795 ACSR	371,590	5,213,842	5,585,432					29
3-795 ACSR								30
3-795 ACSR								31
3-795 ACSR	5,902	1,351,603	1,357,504					32
3-795 ACSR								33
3-795 ACSR	59,673	1,635,478	1,695,151					34
3-795 ACSS	663,115	9,559,156	10,222,271					35
	120,770,039	2,016,652,033	2,137,422,066	577,394	6,692,685	2,889,594	10,159,673	36

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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.
6-397.5 TACSR/TW								1
6-954 ACSS/TW								2
3-795 ACSS	477,246	6,134,098	6,611,344					3
3-795 ACSS	52,746	9,823,670	9,876,416					4
3000 CU								5
3-477 ACSR	16,110	545,815	561,925					6
3-477 ACSR	17,390	648,701	666,091					7
3-477 ACSR								8
3-477 ACSR	25,772	1,120,945	1,146,716					9
3-2312 ACSR								10
3-477 ACSR	143,079	1,706,835	1,849,914					11
3-565.3 ACSS/TW								12
								13
	23,107,966	593,342,523	616,450,488					14
								15
	5,679,689	225,628,295	231,307,984					16
								17
	15,920	28,914,501	28,930,421					18
								19
				577,394	6,692,685	2,889,594	10,159,673	20
								21
								22
								23
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								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	120,770,039	2,016,652,033	2,137,422,066	577,394	6,692,685	2,889,594	10,159,673	36

Schedule Page: 422.2 Line No.: 13 Column: a

NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1000%(10.84 miles) of 30.04 miles of this line; remaining 63.9000%(19.20 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 14 Column: a

NSM ((0972-MN;01) BROOKINGS CO.-HAWKS NEST LAKE) : Xcel Energy owns 67.8174%(12.53 miles) of 18.48 miles of this line; remaining 32.1826%(05.95 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 15 Column: a

NSM ((0972-SD;01) BROOKINGS CO.-HAWKS NEST LAKE) : Xcel Energy owns 67.8174%(07.07 miles) of 10.42 miles of this line; remaining 32.1826%(03.35 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 16 Column: a

NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.8174%(20.72 miles) of 30.55 miles of this line; remaining 32.1826%(09.83 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 19 Column: a

NSM ((0966;01) BROOKINGS CO.-BIG STONE SOUTH) : Xcel Energy owns 50.0000%(35.79 miles) of 71.58 miles of this line; remaining 50.0000%(35.79 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 20 Column: a

NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(27.75 miles) of 43.36 miles of this line; remaining 36.0000%(15.61 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 22 Column: a

NSM ((0964;01) HAMPTON-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(24.22 miles) of 37.85 miles of this line; remaining 36.0000%(13.63 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 23 Column: a

NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8174%(16.64 miles) of 24.54 miles of this line; remaining 32.1826%(07.90 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 24 Column: a

NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8174%(12.27 miles) of 18.1 miles of this line; remaining 32.1826%(05.83 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 25 Column: a

NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8174%(14.15 miles) of 20.87 miles of this line; remaining 32.1826%(06.72 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 26 Column: a

NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8174%(49.55 miles) of 73.06 miles of this line; remaining 32.1826%(23.51 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 27 Column: a

NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8174%(49.57 miles) of 73.1 miles of this line; remaining 32.1826%(23.53 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 28 Column: a

NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8174%(33.56 miles) of 49.49 miles of this line; remaining 32.1826%(15.93 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 29 Column: a

NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8174%(33.56 miles) of 49.49 miles of this line; remaining 32.1826%(15.93 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 30 Column: a

NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1000%(37.65 miles) of 104.29 miles of this line; remaining 63.9000%(66.64 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 32 Column: a

NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1000%(12.45 miles) of 34.49 miles of this line; remaining 63.9000%(22.04 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.2 Line No.: 33 Column: a

NSM ((0954;01) ALEXANDRIA SW. ST.-QUARRY) : Xcel Energy owns 36.1000%(29.32 miles) of 81.22 miles of this line; remaining 63.9000%(51.90 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 5 Column: a

NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8174%(03.37 miles) of 4.97 miles of this line; remaining 32.1826%(01.60 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 7 Column: a

NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 29.8962%(05.78 miles) of 19.32 miles of this line; remaining 70.1038%(13.54 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 8 Column: a

NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2000%(13.48 miles) of 51.46 miles of this line; remaining 73.8000%(37.98 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.3 Line No.: 35 Column: a

NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(09.93 miles) of 15.51 miles of this line; remaining 36.0000%(05.58 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.4 Line No.: 1 Column: a

NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0000%(17.70 miles) of 27.66 miles of this line; remaining 36.0000%(09.96 miles) is owned by other members of the CapX2020 joint venture

Schedule Page: 422.4 Line No.: 14 Column: a

NSM ((5558;01) CEDAR MTN. (GRE)-FRANKLIN) : Xcel Energy owns 67.8174%(02.92 miles) of 4.3 miles of this line; remaining 32.1826%(01.38 miles) is owned by other members of the CapX2020 joint venture.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	(0924;01) MCHENRY (GRE)	MAGIC CITY	20.57	SINGLE POLE	9.00	2	2
2	(5570;01) BLUFF CREEK	SCOTT CO.	2.78	SINGLE POLE	33.00	2	2
3	(5572;01) MCHENRY (GRE)	MAGIC CITY	20.50	SINGLE POLE	27.00	2	2
4	(0850;01) MAGIC CITY	SOURIS	0.79	SINGLE POLE	8.00	1	1
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44	TOTAL		44.64		77.00	7	7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
6-477	ACSRVR2	26/7	230		15,691,260	10,211,537		25,902,797	1
3-795	ACSS	26/7	115		3,988,005	1,329,335		5,317,340	2
6-477	ACSRVR2	26/7	115	83,653	1,594,920	1,472,234		3,150,807	3
6-477	ACSRVR2	26/7	115		1,627,777	805,660		2,433,437	4
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				83,653	22,901,962	13,818,766		36,804,381	44

Schedule Page: 424 Line No.: 1 Column: a

Construction which impacted less than 0.5 miles of an Operating Circuit are not included in this report

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ADAMS-TR09	UNATTENDED TRANSM	345.00	161.00	13.80
2	ADA-TR01	UNATTENDED DISTRIB	69.00	23.00	4.16
3	AFTON-TR01	UNATTENDED DISTRIB	115.00	34.50	
4	AFTON-TR02	UNATTENDED DISTRIB	115.00	34.50	
5	AIR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
6	AIR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
7	AIRPORT-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	AIRPORT-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	ALBANY-TR02	UNATTENDED DISTRIB	69.00	12.50	
10	ALBANY-TR03	UNATTENDED DISTRIB	12.50	4.16	
11	ALDRICH-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	ALDRICH-TR03	UNATTENDED DISTRIB	115.00	13.80	
13	ALDRICH-TR04	UNATTENDED DISTRIB	115.00	13.80	
14	ALEXANDRIA-TR01ABC	UNATTENDED DISTRIB	34.50	4.16	
15	ALTURA-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	ANNANDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	APACHE-TR01	UNATTENDED DISTRIB	115.00	13.80	
18	APACHE-TR02	UNATTENDED DISTRIB	115.00	13.80	
19	ARDEN HILLS-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
20	ARDEN HILLS-TR02	UNATTENDED TRANSM	115.00	69.00	13.80
21	ARLINGTON-TR01	UNATTENDED DISTRIB	69.00	4.16	
22	AS KING-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
23	AS KING-TR91	UNATTENDED DISTRIB	115.00	34.50	
24	ATWATER-TR01	UNATTENDED DISTRIB	69.00	13.80	
25	AVERILL-TR01	UNATTENDED DISTRIB	69.00	23.00	4.00
26	AVON-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	BASSETT CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
28	BASSETT CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
29	BATTLE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	BATTLE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	BAYTOWN-TR01	UNATTENDED DISTRIB	118.00	13.80	
32	BECKER-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	BECKER-TR02	UNATTENDED DISTRIB	69.00	34.50	
34	BELGRADE-TR01	UNATTENDED DISTRIB	69.00	4.16	
35	BELLE PLAINE-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	BIRCH-TR01	UNATTENDED DISTRIB	69.00	34.50	
37	BIRD ISLAND-TR02	UNATTENDED DISTRIB	69.00	4.16	
38	BLUE HERON-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	BLUE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	BLUE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BLUE LAKE-TR07	UNATTENDED TRANSM	230.00	115.00	13.80
2	BLUE LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
3	BLUFF CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	BLUFF CREEK-TR05	UNATTENDED TRANSM	115.00	69.00	13.80
5	BROOKINGS COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	34.50
6	BROOKINGS COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
7	BROOKLYN PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
8	BROOKLYN PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
9	BROOK-TR01ABC	UNATTENDED DISTRIB	34.50	4.16	
10	BROOTEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	BROWNTON-TR01	UNATTENDED DISTRIB	69.00	2.40	
12	BUFFALO LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
13	BUFFALO RIDGE-TR01	UNATTENDED DISTRIB	115.00	34.50	13.80
14	BUFFALO RIDGE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
15	BURNSIDE-TR01	UNATTENDED DISTRIB	69.00	12.50	
16	BURNSIDE-TR02	UNATTENDED DISTRIB	69.00	12.50	
17	BUTTERFIELD-TR01	UNATTENDED DISTRIB	69.00	4.16	
18	CANISTOTA JCT-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	CANISTOTA-TR01ABC	UNATTENDED DISTRIB	69.00	4.16	
20	CANNON FALLS XMSN-TR06	UNATTENDED TRANSM	115.00	69.00	13.80
21	CANNON FALLS XMSN-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
22	CANNON FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	CANTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	CANTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
25	CARVER COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	35.00
26	CARVER COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	35.00
27	CASS COUNTY-TR01XY	UNATTENDED DISTRIB	115.00	23.00	3.00
28	CASS COUNTY-TR02	UNATTENDED DISTRIB	115.00	23.00	
29	CASS COUNTY-TR03	UNATTENDED DISTRIB	115.00	23.00	14.00
30	CASTLE ROCK-TR01	UNATTENDED DISTRIB	69.00	4.00	
31	CEDAR LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	CEDAR LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	CEDARVALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	CEDARVALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	CENTERVILLE-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	CHANARAMBIE-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
37	CHANARAMBIE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
38	CHANARAMBIE-TR04	UNATTENDED DISTRIB	115.00	34.50	14.00
39	CHEMOLITE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	CHEMOLITE-TR02	UNATTENDED DISTRIB	115.00	13.80	

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	CHERRY CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	CHERRY CREEK-TR03	UNATTENDED DISTRIB	115.00	34.50	
3	CHISAGO COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	
4	CHISAGO COUNTY-TR05	UNATTENDED TRANSM	345.00	115.00	35.00
5	CHISAGO COUNTY-TR06	UNATTENDED TRANSM	345.00	115.00	35.00
6	CHISAGO COUNTY-TR09ABC	UNATTENDED TRANSM	500.00	345.00	35.00
7	CHISAGO COUNTY-TR10ABC	UNATTENDED TRANSM	500.00	345.00	35.00
8	CLARA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	CLARA CITY-TR02	UNATTENDED DISTRIB	69.00	23.00	
10	CLARKS GROVE-TR01	UNATTENDED DISTRIB	69.00	7.20	
11	CLIFF AVENUE-TR01	UNATTENDED DISTRIB	69.00	4.16	
12	CLIFF AVENUE-TR02	UNATTENDED DISTRIB	69.00	13.80	
13	COKATO-TR01	UNATTENDED DISTRIB	69.00	13.80	
14	COLVILL-TR04	UNATTENDED TRANSM	115.00	69.00	14.00
15	COLVILL-TR05	UNATTENDED TRANSM	161.00	115.00	14.00
16	COON CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	COON CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	COON CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
19	COON CREEK-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
20	COTTAGE GROVE-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	COTTAGE GROVE-TR02	UNATTENDED DISTRIB	115.00	13.80	
22	CREDIT RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
23	CREDIT RIVER-TR02	UNATTENDED DISTRIB	69.00	12.50	
24	CROOKED LAKE-TR01	UNATTENDED DISTRIB	119.00	13.80	
25	CROOKED LAKE-TR02	UNATTENDED DISTRIB	119.00	13.80	
26	CROOKED LAKE-TR03	UNATTENDED DISTRIB	115.00	12.50	
27	CROOKED LAKE-TR65ABC	UNATTENDED DISTRIB	13.80	12.50	
28	CROSSROADS-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	CROSSROADS-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	CROSSROADS-TR03	UNATTENDED DISTRIB	115.00	13.80	
31	CRYSTAL FOODS-TR01	UNATTENDED DISTRIB	69.00	13.80	
32	DAHLGREN-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	DANUBE-TR01	UNATTENDED DISTRIB	69.00	12.50	
34	DASSEL-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	DAYTONS BLUFF-TR01	UNATTENDED DISTRIB	115.00	13.80	
36	DAYTONS BLUFF-TR02	UNATTENDED DISTRIB	115.00	13.80	
37	DAYTONS BLUFF-TR03	UNATTENDED DISTRIB	115.00	13.80	
38	DEEPHAVEN-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	DEEPHAVEN-TR02	UNATTENDED DISTRIB	69.00	13.80	
40	DELANO-TR01XY	UNATTENDED DISTRIB	69.00	7.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	DELL RAPIDS-TR02	UNATTENDED DISTRIB	34.50	12.50	
2	DODGE CENTER-TR01	UNATTENDED DISTRIB	69.00	23.00	
3	DODGE CENTER-TR02	UNATTENDED DISTRIB	69.00	12.50	
4	DODGE CENTER-TR03	UNATTENDED DISTRIB	69.00	12.50	
5	DOME PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
6	DOUGLAS COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	35.00
7	DOUGLAS COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
8	DOUGLAS COUNTY-TR03	UNATTENDED DISTRIB	69.00	13.80	
9	DUNDAS-TR01	UNATTENDED DISTRIB	69.00	13.80	
10	DUNDAS-TR02	UNATTENDED DISTRIB	69.00	13.80	
11	EAGLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	EAST BLOOMINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	EAST BLOOMINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	EAST BLOOMINGTON-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	EAST WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
16	EASTWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
17	EASTWOOD-TR02	UNATTENDED DISTRIB	69.00	13.80	
18	EASTWOOD-TR03	UNATTENDED DISTRIB	115.00	13.80	
19	ECHO-TR01	UNATTENDED DISTRIB	23.00	4.16	
20	EDEN PRAIRIE-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	EDEN PRAIRIE-TR03	UNATTENDED DISTRIB	115.00	13.80	
22	EDEN PRAIRIE-TR04	UNATTENDED DISTRIB	115.00	13.80	
23	EDEN PRAIRIE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
24	EDEN PRAIRIE-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
25	EDGERTON-TR01	UNATTENDED DISTRIB	23.00	4.16	
26	EDINA-TR01	UNATTENDED DISTRIB	115.00	13.80	
27	EDINA-TR02	UNATTENDED DISTRIB	115.00	13.80	
28	EDINA-TR03	UNATTENDED DISTRIB	115.00	13.80	
29	ELLIOT PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
30	ELLIOT PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
31	ELLIOT PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
32	ELM CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	ELM CREEK-TR02	UNATTENDED DISTRIB	115.00	34.50	
34	ELM CREEK-TR03	UNATTENDED DISTRIB	115.00	13.80	
35	ELM CREEK-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
36	EMERY-TR01ABC	UNATTENDED DISTRIB	34.50	4.16	
37	ESSIG-TR01ABC	UNATTENDED DISTRIB	69.00	2.40	
38	EXCELSIOR-TR01	UNATTENDED DISTRIB	69.00	13.80	
39	FAIR PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
40	FAIR PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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1	FALLS-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	FALLS-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	FARIBAULT-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	FARIBAULT-TR02	UNATTENDED DISTRIB	69.00	13.80	
5	FARMINGTON-TR01	UNATTENDED DISTRIB	69.00	13.80	
6	FARMINGTON-TR02	UNATTENDED DISTRIB	69.00	13.80	
7	FENTON-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
8	FENTON-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
9	FENTON-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
10	FIESTA CITY-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	FIESTA CITY-TR02	UNATTENDED DISTRIB	69.00	12.50	
12	FIFTH STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
13	FIFTH STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
14	FIFTH STREET-TR03	UNATTENDED DISTRIB	115.00	13.80	
15	FIFTH STREET-TR04	UNATTENDED DISTRIB	115.00	13.80	
16	FIRST LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
17	FOLEY-TR01	UNATTENDED DISTRIB	34.50	4.16	
18	FORBES-TR09	UNATTENDED DISTRIB	500.00	20.00	
19	FORT RIDGELY-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
20	FRANKLIN-TR04	UNATTENDED DISTRIB	69.00	23.00	
21	FRANKLIN-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
22	FRANKLIN-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
23	FRANKLIN-TR07	UNATTENDED DISTRIB	69.00	4.16	
24	FRONTENAC-TR01	UNATTENDED DISTRIB	69.00	12.50	
25	GATEWAY-TR01	UNATTENDED DISTRIB	69.00	12.50	
26	GATEWAY-TR02	UNATTENDED DISTRIB	69.00	12.50	
27	GAYLORD-TR01	UNATTENDED DISTRIB	69.00	4.00	
28	GIBBON-TR01	UNATTENDED DISTRIB	69.00	12.50	
29	GLEASON LAKE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
30	GLEASON LAKE-TR03	UNATTENDED DISTRIB	34.50	13.80	
31	GLEASON LAKE-TR04	UNATTENDED DISTRIB	115.00	34.50	
32	GLEASON LAKE-TR07	UNATTENDED DISTRIB	115.00	13.80	
33	GLEASON LAKE-TR08	UNATTENDED DISTRIB	115.00	13.80	
34	GLEN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	GLEN LAKE-TR02	UNATTENDED DISTRIB	69.00	13.80	
36	GLENWOOD-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	GLENWOOD-TR02	UNATTENDED DISTRIB	69.00	12.50	
38	GOODVIEW-TR01	UNATTENDED DISTRIB	69.00	12.50	
39	GOODVIEW-TR02	UNATTENDED DISTRIB	69.00	12.50	
40	GOOSE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

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	GOOSE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	GOPHER-TR01	UNATTENDED DISTRIB	115.00	13.80	
3	GOPHER-TR02	UNATTENDED DISTRIB	115.00	13.80	
4	GRANITE CITY-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	GRANITE CITY-TR02	UNATTENDED DISTRIB	115.00	13.80	
6	GRANITE CITY-TR03	UNATTENDED DISTRIB	115.00	34.50	
7	GRANT-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
8	GRANT-TR03	UNATTENDED DISTRIB	115.00	34.50	
9	GREEN ISLE-TR01	UNATTENDED DISTRIB	69.00	4.16	
10	GREENFIELD-TR01	UNATTENDED DISTRIB	69.00	12.50	
11	HADLEY-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	HASSAN-TR01	UNATTENDED DISTRIB	115.00	34.50	
13	HASSAN-TR02	UNATTENDED DISTRIB	115.00	34.50	
14	HASTINGS-TR01	UNATTENDED DISTRIB	69.00	12.50	
15	HASTINGS-TR02	UNATTENDED DISTRIB	69.00	12.50	
16	HATFIELD-TR01ABC	UNATTENDED DISTRIB	23.00	12.50	
17	HATTON-TR01	UNATTENDED DISTRIB	69.00	4.16	
18	HAZEL CREEK-TR09	UNATTENDED TRANSM	345.00	230.00	14.00
19	HECTOR-TR01	UNATTENDED DISTRIB	69.00	4.16	
20	HENDERSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
21	HIAWATHA WEST-TR01	UNATTENDED DISTRIB	115.00	13.80	
22	HIGH BRIDGE-TR04	UNATTENDED DISTRIB	115.00	13.80	
23	HOLLYDALE-TR01	UNATTENDED DISTRIB	69.00	13.80	
24	HOLLYDALE-TR02	UNATTENDED DISTRIB	34.50	13.80	
25	HOWARD LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
26	HUGO-TR01	UNATTENDED DISTRIB	115.00	34.50	
27	HUGO-TR02	UNATTENDED DISTRIB	115.00	34.50	
28	HYLAND LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	HYLAND LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	INDIANA-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	INDIANA-TR02	UNATTENDED DISTRIB	115.00	13.80	
32	INDUSTRIAL-TR01	UNATTENDED DISTRIB	34.50	4.16	
33	INDUSTRIAL-TR02	UNATTENDED DISTRIB	34.50	4.16	
34	INVER GROVE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
35	INVER GROVE-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
36	INVER HILLS-PLTSDU	UNATTENDED DISTRIB	34.50	13.80	
37	INVER HILLS-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
38	JORDAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
39	KASSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
40	KASSON-TR02	UNATTENDED DISTRIB	69.00	12.50	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KEGAN LAKE-TR01	UNATTENDED DISTRIB	69.00	13.80	
2	KENYON-TR01	UNATTENDED DISTRIB	69.00	12.50	
3	KIMBALL-TR01	UNATTENDED DISTRIB	69.00	12.50	
4	KOCH REFINERY-TR11	UNATTENDED DISTRIB	115.00	13.80	
5	KOCH REFINERY-TR12	UNATTENDED DISTRIB	115.00	13.80	
6	KOCH REFINERY-TR13	UNATTENDED DISTRIB	115.00	13.80	
7	KOCH REFINERY-TR14	UNATTENDED DISTRIB	115.00	13.80	
8	KOCH REFINERY-TR15	UNATTENDED DISTRIB	115.00	13.80	
9	KOCH REFINERY-TR16	UNATTENDED DISTRIB	115.00	13.80	
10	KOHLMAN LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	KOHLMAN LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
12	KOHLMAN LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
13	KOHLMAN LAKE-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
14	LA CRESCENT-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	LAFAYETTE-TR01	UNATTENDED DISTRIB	69.00	4.16	
16	LAKE BAVARIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
17	LAKE EMILY-TR01	UNATTENDED DISTRIB	69.00	13.80	
18	LAKE LILLIAN-TR01	UNATTENDED DISTRIB	69.00	12.50	
19	LAKE PULASKI-TR03	UNATTENDED DISTRIB	115.00	34.50	
20	LAKE PULASKI-TR05	UNATTENDED TRANSM	115.00	69.00	35.00
21	LAKE PULASKI-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
22	LAKE YANKTON-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
23	LAKE YANKTON-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
24	LAKE YANKTON-TR03	UNATTENDED DISTRIB	69.00	13.80	
25	LARIMORE-TR01	UNATTENDED DISTRIB	69.00	4.16	
26	LAWRENCE CREEK-TR01	UNATTENDED DISTRIB	115.00	34.50	
27	LAWRENCE CREEK-TR04	UNATTENDED TRANSM	115.00	69.00	14.00
28	LAWRENCE CREEK-TR05	UNATTENDED TRANSM	161.00	115.00	14.00
29	LAWRENCE-TR01	UNATTENDED DISTRIB	115.00	34.50	
30	LAWRENCE-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
31	LAWRENCE-TR08	UNATTENDED TRANSM	115.00	69.00	14.00
32	LENNOX-TR01	UNATTENDED DISTRIB	69.00	13.80	
33	LESTER PRAIRIE-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	LEXINGTON-TR01	UNATTENDED DISTRIB	115.00	13.80	
35	LEXINGTON-TR02	UNATTENDED DISTRIB	115.00	13.80	
36	LEXINGTON-TR03	UNATTENDED DISTRIB	115.00	34.50	
37	LEXINGTON-TR04	UNATTENDED DISTRIB	34.50	13.80	
38	LINCOLN COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
39	LINCOLN COUNTY-TR07	UNATTENDED DISTRIB	115.00	13.80	
40	LINCOLN COUNTY-TR08	UNATTENDED DISTRIB	115.00	13.80	

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	LINDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	LINDSTROM-TR01	UNATTENDED DISTRIB	115.00	12.50	
3	LINDSTROM-TR02	UNATTENDED DISTRIB	115.00	12.50	
4	LINN STREET-TR01	UNATTENDED DISTRIB	69.00	12.50	
5	LINN STREET-TR02	UNATTENDED DISTRIB	69.00	12.50	
6	LONE OAK-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	LONE OAK-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	LONG LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	LONG LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	LOUISE-TR01	UNATTENDED DISTRIB	115.00	13.80	
11	LOWRY-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	LYON COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
13	LYON COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
14	M E INTERNATIONAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	M E INTERNATIONAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	MAIN STREET-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	MAIN STREET-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	MAPLE LAKE-TR01	UNATTENDED DISTRIB	69.00	12.50	
19	MAPLE RIVER-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
20	MAPLE RIVER-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
21	MAPLETON-TR01	UNATTENDED DISTRIB	69.00	13.80	
22	MARION-TR01	UNATTENDED DISTRIB	23.00	4.16	
23	MAXWELL-TR01	UNATTENDED DISTRIB	115.00	4.16	
24	MAYHEW LAKE-TR01	UNATTENDED DISTRIB	115.00	34.50	
25	MAYNARD TRANSMISSION-TR01	UNATTENDED TRANSM	115.00	69.00	
26	MAYNARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	MAYVILLE-TR01	UNATTENDED DISTRIB	69.00	4.16	
28	MAYVILLE-TR02	UNATTENDED DISTRIB	69.00	12.50	
29	MAZEPPA-TR01	UNATTENDED DISTRIB	69.00	12.50	
30	MEDFORD JUNCTION-TR01	UNATTENDED DISTRIB	69.00	12.50	
31	MEDICINE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	MEDICINE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
33	MEDICINE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
34	MEIRE GROVE-TR01	UNATTENDED DISTRIB	69.00	12.50	
35	MERIDEN-TR01	UNATTENDED DISTRIB	69.00	12.50	
36	MERRIAM PARK-TR01	UNATTENDED DISTRIB	115.00	13.80	
37	MERRIAM PARK-TR02	UNATTENDED DISTRIB	115.00	13.80	
38	MERRIAM PARK-TR03	UNATTENDED DISTRIB	115.00	13.80	
39	MIDTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	MINNEHAHA-TR01	UNATTENDED DISTRIB	115.00	13.80	

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Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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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	MINNEHAHA-TR02	UNATTENDED DISTRIB	115.00	13.80	
2	MINNESOTA LAKE-TR01	UNATTENDED DISTRIB	69.00	4.16	
3	MINNESOTA PIPELINE-TR01	UNATTENDED DISTRIB	115.00	4.16	
4	MINNESOTA VALLEY-TR02	UNATTENDED DISTRIB	69.00	23.00	
5	MINNESOTA VALLEY-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
6	MINNESOTA VALLEY-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
7	MINNESOTA VALLEY-TR11	UNATTENDED TRANSM	115.00	69.00	14.00
8	MINNESOTA VALLEY-TR12	UNATTENDED TRANSM	115.00	69.00	14.00
9	MONTEVIDEO-TR01	UNATTENDED DISTRIB	69.00	4.16	
10	MONTEVIDEO-TR02	UNATTENDED DISTRIB	69.00	12.50	
11	MONTICELLO-TR06	UNATTENDED TRANSM	345.00	230.00	14.00
12	MONTICELLO-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
13	MONTROSE-TR01	UNATTENDED DISTRIB	69.00	12.50	
14	MOORE LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	MOORE LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	MOORE LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
17	MORGAN-TR01	UNATTENDED DISTRIB	69.00	23.00	
18	MORRISTOWN-TR01	UNATTENDED DISTRIB	69.00	12.50	
19	MOUND-TR01	UNATTENDED DISTRIB	69.00	13.80	
20	MOUND-TR02	UNATTENDED DISTRIB	69.00	13.80	
21	NERSTRAND-TR01XY	UNATTENDED DISTRIB	69.00	12.50	
22	NINE MILE CREEK-TR01	UNATTENDED DISTRIB	115.00	13.80	
23	NINE MILE CREEK-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	NOBLES COUNTY-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
25	NOBLES COUNTY-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
26	NOBLES COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
27	NOBLES COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
28	NORDIC-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	NORDIC-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	NORTH BROADWAY-TR01	UNATTENDED DISTRIB	23.00	4.16	
31	NORTH BROADWAY-TR02	UNATTENDED DISTRIB	23.00	4.16	
32	NORTH ROCHESTER-TR09	UNATTENDED TRANSM	345.00	161.00	35.00
33	NORTH STAR STEEL-TR01	UNATTENDED DISTRIB	115.00	13.80	
34	NORTH STAR STEEL-TR02	UNATTENDED DISTRIB	115.00	13.80	
35	NORTH STAR STEEL-TR03	UNATTENDED DISTRIB	115.00	13.80	
36	NORTHFIELD-TR01	UNATTENDED DISTRIB	69.00	13.80	
37	NORTHFIELD-TR02	UNATTENDED DISTRIB	69.00	13.80	
38	OAK PARK-TR01	UNATTENDED DISTRIB	115.00	23.00	14.00
39	OAK PARK-TR07	UNATTENDED DISTRIB	115.00	13.80	
40	OAK PARK-TR08	UNATTENDED DISTRIB	115.00	13.80	

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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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1	OAKDALE-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	OAKDALE-TR02	UNATTENDED DISTRIB	115.00	13.80	
3	ORONO-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	OSSEO-TR01	UNATTENDED DISTRIB	115.00	13.80	
5	OSSEO-TR02	UNATTENDED DISTRIB	115.00	13.80	
6	PARKERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	PARKERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	PARKERS LAKE-TR03	UNATTENDED DISTRIB	115.00	13.80	
9	PARKERS LAKE-TR09ABC	UNATTENDED TRANSM	345.00	115.00	14.00
10	PARKERS LAKE-TR10ABC	UNATTENDED TRANSM	345.00	115.00	14.00
11	PAYNESVILLE XMSN-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
12	PAYNESVILLE XMSN-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
13	PAYNESVILLE XMSN-TR04	UNATTENDED DISTRIB	115.00	34.50	
14	PAYNESVILLE XMSN-TR09	UNATTENDED TRANSM	230.00	115.00	14.00
15	PINE BEND-TR03	UNATTENDED DISTRIB	69.00	13.80	
16	PINE ISLAND-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	PINE ISLAND-TR02	UNATTENDED DISTRIB	69.00	12.50	
18	PIPESTONE-TR01	UNATTENDED DISTRIB	69.00	13.80	
19	PIPESTONE-TR02	UNATTENDED DISTRIB	69.00	4.16	
20	PIPESTONE-TR03	UNATTENDED DISTRIB	69.00	25.00	
21	PIPESTONE-TR05	UNATTENDED TRANSM	115.00	69.00	3.00
22	PIPESTONE-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
23	PLATO-TR01	UNATTENDED DISTRIB	115.00	12.50	
24	PRAIRIE ISLAND-TR10	UNATTENDED TRANSM	345.00	161.00	14.00
25	PRAIRIE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
26	PRAIRIE-TR03	UNATTENDED TRANSM	115.00	69.00	14.00
27	PRAIRIE-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
28	PRAIRIE-TR07	UNATTENDED TRANSM	230.00	115.00	14.00
29	PRAIRIE-TR08	UNATTENDED TRANSM	230.00	115.00	14.00
30	PRIOR-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	QUARRY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
32	RAMSEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
33	RAMSEY-TR02	UNATTENDED DISTRIB	115.00	13.80	
34	RAPIDAN-TR01	UNATTENDED DISTRIB	69.00	13.80	
35	RED RIVER-TR01	UNATTENDED DISTRIB	115.00	23.00	14.00
36	RED RIVER-TR02	UNATTENDED DISTRIB	115.00	23.00	14.00
37	RED RIVER-TR03	UNATTENDED DISTRIB	115.00	23.00	5.00
38	RED ROCK-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	RED ROCK-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	RED ROCK-TR03	UNATTENDED DISTRIB	115.00	13.80	

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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	RED ROCK-TR05	UNATTENDED TRANSM	345.00	230.00	14.00
2	RED ROCK-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
3	RED ROCK-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
4	RED WING-TR01	UNATTENDED DISTRIB	69.00	13.80	
5	RED WING-TR02	UNATTENDED DISTRIB	69.00	13.80	
6	RENVILLE-TR01	UNATTENDED DISTRIB	69.00	12.50	
7	REYNOLDS-TR01	UNATTENDED DISTRIB	69.00	12.50	
8	RICH SPRING-TR01	UNATTENDED DISTRIB	69.00	13.80	
9	RICH VALLEY-TR01	UNATTENDED DISTRIB	115.00	13.80	
10	RICHMOND-TR01	UNATTENDED DISTRIB	69.00	13.80	
11	RIVERSIDE-TR01	UNATTENDED DISTRIB	115.00	13.80	
12	RIVERSIDE-TR02	UNATTENDED DISTRIB	115.00	13.80	
13	RIVERWOOD-TR01	UNATTENDED DISTRIB	115.00	13.80	
14	RIVERWOOD-TR02	UNATTENDED DISTRIB	115.00	13.80	
15	ROCK RIVER-TR01	UNATTENDED DISTRIB	69.00	23.00	
16	ROGERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
17	ROGERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
18	ROSE PLACE-TR01	UNATTENDED DISTRIB	115.00	13.80	
19	ROSE PLACE-TR02	UNATTENDED DISTRIB	115.00	13.80	
20	ROSEMOUNT-TR01	UNATTENDED DISTRIB	115.00	34.50	
21	SACRED HEART-TR01	UNATTENDED DISTRIB	69.00	13.80	4.00
22	SALEM-TR01ABC	UNATTENDED DISTRIB	69.00	34.50	3.00
23	SALEM-TR02	UNATTENDED DISTRIB	69.00	13.80	
24	SALIDA CROSSING-TR01	UNATTENDED DISTRIB	115.00	13.80	
25	SARTELL-TR01	UNATTENDED DISTRIB	34.50	12.50	2.00
26	SAUK RIVER-TR01	UNATTENDED DISTRIB	115.00	34.50	
27	SAUK RIVER-TR02	UNATTENDED DISTRIB	115.00	34.50	
28	SAVAGE-TR01	UNATTENDED DISTRIB	115.00	13.80	
29	SAVAGE-TR02	UNATTENDED DISTRIB	115.00	13.80	
30	SCANDIA-TR01	UNATTENDED DISTRIB	69.00	12.50	
31	SCOTT COUNTY-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
32	SCOTT COUNTY-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
33	SCOTT COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
34	SCOTT COUNTY-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
35	SEDAN-TR01 AB	UNATTENDED DISTRIB	69.00	7.20	
36	SHEAS LAKE-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
37	SHEAS LAKE-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
38	SHEPARD-TR01	UNATTENDED DISTRIB	115.00	13.80	
39	SHEPARD-TR02	UNATTENDED DISTRIB	115.00	13.80	
40	SHERBURNE COUNTY-TR09	UNATTENDED TRANSM	345.00	115.00	14.00

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SHEYENNE-TR05	UNATTENDED TRANSM	230.00	115.00	14.00
2	SHEYENNE-TR06	UNATTENDED TRANSM	230.00	115.00	14.00
3	SIBLEY PARK-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	SIBLEY PARK-TR02	UNATTENDED DISTRIB	69.00	13.80	
5	SIOUX FALLS-TR07	UNATTENDED DISTRIB	69.00	13.80	
6	SIOUX FALLS-TR08	UNATTENDED DISTRIB	69.00	13.80	
7	SLAYTON WEST-TR01	UNATTENDED DISTRIB	69.00	13.80	
8	SOURIS-TR01	UNATTENDED DISTRIB	115.00	13.80	
9	SOURIS-TR02	UNATTENDED DISTRIB	115.00	13.80	
10	SOURIS-TR03	UNATTENDED DISTRIB	115.00	13.80	
11	SOUTH BEND-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
12	SOUTH BEND-TR06	UNATTENDED TRANSM	161.00	115.00	14.00
13	SOUTH HAVEN-TR01	UNATTENDED DISTRIB	69.00	34.50	
14	SOUTH RENNER-TR01	UNATTENDED DISTRIB	115.00	34.50	
15	SOUTH RIDGE-TR01	UNATTENDED DISTRIB	69.00	23.00	
16	SOUTH SIOUX FALLS-TR01	UNATTENDED DISTRIB	69.00	4.16	
17	SOUTH SIOUX FALLS-TR02	UNATTENDED DISTRIB	69.00	4.16	
18	SOUTH SIOUX FALLS-TR03	UNATTENDED DISTRIB	69.00	13.80	
19	SOUTH SIOUX FALLS-TR04	UNATTENDED DISTRIB	69.00	13.80	
20	SOUTHTOWN-TR01	UNATTENDED DISTRIB	115.00	13.80	
21	SOUTHTOWN-TR02	UNATTENDED DISTRIB	115.00	13.80	
22	SOUTHTOWN-TR03	UNATTENDED DISTRIB	115.00	13.80	
23	SOUTH-TR01ABC	UNATTENDED DISTRIB	69.00	2.40	
24	SPLIT ROCK-TR06	UNATTENDED TRANSM	161.00	115.00	35.00
25	SPLIT ROCK-TR07	UNATTENDED TRANSM	230.00	115.00	14.00
26	SPLIT ROCK-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
27	SPLIT ROCK-TR11	UNATTENDED TRANSM	345.00	115.00	14.00
28	ST CLAIR-TR01	UNATTENDED DISTRIB	13.20	4.16	
29	ST CLAIR-TR02	UNATTENDED DISTRIB	13.20	4.16	
30	ST CLOUD-TR01	UNATTENDED DISTRIB	115.00	34.50	
31	ST CLOUD-TR02	UNATTENDED DISTRIB	115.00	34.50	
32	ST JAMES MUNICIPAL-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	ST JOHNS-TR01	UNATTENDED DISTRIB	69.00	4.16	
34	ST JOSEPH-TR01	UNATTENDED DISTRIB	69.00	4.16	
35	ST LOUIS PARK-TR02	UNATTENDED DISTRIB	115.00	34.50	
36	ST LOUIS PARK-TR04	UNATTENDED DISTRIB	115.00	13.80	
37	ST LOUIS PARK-TR05	UNATTENDED DISTRIB	115.00	13.80	
38	ST LOUIS PARK-TR06	UNATTENDED DISTRIB	115.00	13.80	
39	ST. PAUL WATER-TR01	UNATTENDED DISTRIB	13.80	4.16	
40	STEWART-TR01	UNATTENDED DISTRIB	69.00	12.50	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STOCKYARDS-TR01	UNATTENDED DISTRIB	115.00	13.80	
2	STOCKYARDS-TR02	UNATTENDED DISTRIB	118.00	13.80	
3	SUMMIT AVENUE-TR01	UNATTENDED DISTRIB	115.00	13.80	
4	SUMMIT AVENUE-TR02	UNATTENDED DISTRIB	115.00	13.80	
5	SWAN LAKE-TR01	UNATTENDED DISTRIB	115.00	12.50	
6	TANNERS LAKE-TR01	UNATTENDED DISTRIB	115.00	13.80	
7	TANNERS LAKE-TR02	UNATTENDED DISTRIB	115.00	13.80	
8	TANNERS LAKE-TR23A1B1C1	UNATTENDED DISTRIB	13.80	12.50	
9	TANNERS LAKE-TR23A2B2C2	UNATTENDED DISTRIB	13.80	12.50	
10	TANNERS LAKE-TR32A1B1C1	UNATTENDED DISTRIB	13.80	12.50	
11	TANNERS LAKE-TR32A2B2C2	UNATTENDED DISTRIB	13.80	12.50	
12	TANNERS LAKE-TR34A1B1C1	UNATTENDED DISTRIB	13.80	12.50	
13	TANNERS LAKE-TR34A2B2C2	UNATTENDED DISTRIB	13.80	12.50	
14	TERMINAL-TR01	UNATTENDED DISTRIB	115.00	13.80	
15	TERMINAL-TR02	UNATTENDED DISTRIB	115.00	13.80	
16	TERMINAL-TR03	UNATTENDED DISTRIB	115.00	13.80	
17	TERMINAL-TR09	UNATTENDED TRANSM	345.00	115.00	35.00
18	TERMINAL-TR10	UNATTENDED TRANSM	345.00	115.00	35.00
19	THOMPSON-TR01	UNATTENDED DISTRIB	69.00	12.50	
20	TRACY SWITCHING-TR01	UNATTENDED DISTRIB	69.00	13.80	
21	TRACY-TR01	UNATTENDED DISTRIB	69.00	4.16	2.00
22	TWIN LAKES-TR01	UNATTENDED DISTRIB	115.00	13.80	
23	TWIN LAKES-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	TWIN LAKES-TR03	UNATTENDED DISTRIB	115.00	13.80	
25	UPPER LEVEE-TR01	UNATTENDED DISTRIB	115.00	13.80	
26	UPPER LEVEE-TR02	UNATTENDED DISTRIB	115.00	13.80	
27	UPPER LEVEE-TR03	UNATTENDED DISTRIB	115.00	13.80	
28	VERMILLION RIVER-TR03	UNATTENDED DISTRIB	115.00	13.80	
29	VERMILLION-TR01	UNATTENDED DISTRIB	13.80	7.20	
30	VESELI-TR01	UNATTENDED DISTRIB	69.00	12.50	
31	VIKING-TR01	UNATTENDED DISTRIB	115.00	13.80	
32	VILLARD-TR01	UNATTENDED DISTRIB	69.00	12.50	
33	WABASHA-TR01	UNATTENDED DISTRIB	69.00	13.80	
34	WABASHA-TR02	UNATTENDED DISTRIB	69.00	2.40	
35	WACONIA-TR01	UNATTENDED DISTRIB	69.00	13.80	
36	WAKEFIELD-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
37	WAKEFIELD-TR02ABC	UNATTENDED DISTRIB	34.50	13.80	
38	WAKEFIELD-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
39	WASECA-TR02	UNATTENDED DISTRIB	69.00	23.00	
40	WASECA-TR03	UNATTENDED DISTRIB	69.00	23.00	

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Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WASECA-TR04	UNATTENDED DISTRIB	69.00	23.00	
2	WATAB RIVER-TR01	UNATTENDED DISTRIB	69.00	12.50	
3	WATERTOWN-TR01	UNATTENDED DISTRIB	69.00	13.80	
4	WATERVILLE-TR01	UNATTENDED DISTRIB	69.00	23.00	
5	WATERVILLE-TR02	UNATTENDED DISTRIB	69.00	4.16	
6	WATERVILLE-TR03	UNATTENDED DISTRIB	69.00	12.50	
7	WATKINS-TR01	UNATTENDED DISTRIB	69.00	4.16	
8	WAVERLY-TR01	UNATTENDED DISTRIB	69.00	12.50	
9	WELLS CREEK-TR01	UNATTENDED DISTRIB	69.00	12.50	
10	WESCOTT PROPANE PLANT-TR01	UNATTENDED DISTRIB	69.00	13.80	
11	WEST BYRON-TR01	UNATTENDED DISTRIB	69.00	12.50	
12	WEST COON RAPIDS-TR01	UNATTENDED DISTRIB	115.00	34.50	
13	WEST COON RAPIDS-TR02	UNATTENDED DISTRIB	115.00	34.50	
14	WEST COON RAPIDS-TR03	UNATTENDED DISTRIB	34.50	13.80	
15	WEST FARIBAULT-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
16	WEST FARIBAULT-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
17	WEST FARIBAULT-TR03	UNATTENDED DISTRIB	69.00	13.80	
18	WEST FARIBAULT-TR07	UNATTENDED DISTRIB	69.00	13.80	
19	WEST HASTINGS-TR01	UNATTENDED DISTRIB	115.00	12.50	
20	WEST HASTINGS-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
21	WEST NEW ULM-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
22	WEST RIVER ROAD-TR01	UNATTENDED DISTRIB	115.00	13.80	
23	WEST RIVER ROAD-TR02	UNATTENDED DISTRIB	115.00	13.80	
24	WEST RIVER ROAD-TR03	UNATTENDED DISTRIB	115.00	13.80	
25	WEST SIOUX FALLS-TR05	UNATTENDED TRANSM	115.00	69.00	14.00
26	WEST SIOUX FALLS-TR07	UNATTENDED DISTRIB	115.00	13.80	
27	WEST SIOUX FALLS-TR08	UNATTENDED DISTRIB	115.00	13.80	
28	WEST WACONIA-TR01	UNATTENDED DISTRIB	115.00	34.50	
29	WEST WACONIA-TR02	UNATTENDED DISTRIB	115.00	34.50	
30	WESTERN-TR01	UNATTENDED DISTRIB	115.00	13.80	
31	WESTERN-TR02	UNATTENDED DISTRIB	115.00	13.80	
32	WESTGATE-TR01	UNATTENDED TRANSM	115.00	69.00	14.00
33	WESTGATE-TR02	UNATTENDED TRANSM	115.00	69.00	14.00
34	WESTGATE-TR03	UNATTENDED DISTRIB	115.00	13.80	
35	WESTGATE-TR04	UNATTENDED DISTRIB	115.00	13.80	
36	WESTGATE-TR05	UNATTENDED DISTRIB	115.00	34.50	
37	WESTGATE-TR06	UNATTENDED DISTRIB	115.00	34.50	
38	WESTPORT-TR01X AB,Y CB	UNATTENDED DISTRIB	69.00	7.20	
39	WILLIAM BROS PIPELINE-TR01	UNATTENDED DISTRIB	115.00	13.80	
40	WILLIAM BROS PIPELINE-TR01B	UNATTENDED DISTRIB	13.80	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WILLIAM BROS PIPELINE-TR02	UNATTENDED DISTRIB	13.80	2.40	
2	WILLIAM BROS PIPELINE-TR03	UNATTENDED DISTRIB	115.00	13.80	
3	WILMARTH-TR06	UNATTENDED TRANSM	115.00	69.00	14.00
4	WILMARTH-TR07	UNATTENDED TRANSM	115.00	69.00	14.00
5	WILMARTH-TR08	UNATTENDED TRANSM	115.00	69.00	14.00
6	WILMARTH-TR09	UNATTENDED TRANSM	345.00	115.00	14.00
7	WILMARTH-TR10	UNATTENDED TRANSM	345.00	115.00	14.00
8	WILSON-TR03	UNATTENDED DISTRIB	115.00	13.80	
9	WILSON-TR04	UNATTENDED DISTRIB	115.00	13.80	
10	WILSON-TR05	UNATTENDED DISTRIB	115.00	13.80	
11	WINONA-TR01	UNATTENDED DISTRIB	69.00	13.80	
12	WINONA-TR02	UNATTENDED DISTRIB	69.00	13.80	
13	WINONA-TR03	UNATTENDED DISTRIB	69.00	13.80	
14	WINSTED-TR01	UNATTENDED DISTRIB	69.00	13.80	
15	WINTHROP-TR01	UNATTENDED DISTRIB	69.00	4.16	
16	WOBEGON TRAIL-TR01	UNATTENDED DISTRIB	69.00	12.50	
17	WOODBURY-TR01	UNATTENDED DISTRIB	115.00	34.50	
18	WOODBURY-TR02	UNATTENDED DISTRIB	115.00	34.50	
19	WYOMING-TR01	UNATTENDED DISTRIB	115.00	12.50	
20	WYOMING-TR02	UNATTENDED DISTRIB	115.00	12.50	
21	YANKEE-TR01	UNATTENDED DISTRIB	115.00	34.50	14.00
22	YANKEE-TR02	UNATTENDED DISTRIB	115.00	34.50	14.00
23	YELLOW MEDICINE-TR01	UNATTENDED DISTRIB	69.00	23.00	
24	YOUNG AMERICA-TR01	UNATTENDED DISTRIB	69.00	13.80	
25	YOUNG AMERICA-TR02	UNATTENDED DISTRIB	69.00	13.80	
26	ZUMBRO FALLS-TR01	UNATTENDED DISTRIB	69.00	12.50	
27	ZUMBROTA-TR01	UNATTENDED DISTRIB	69.00	13.80	
28	587				
29					
30	Count TTL Transformer Banks	587			
31	Count TTL Transformers In Service	631			
32	TTL MVA In Service	45,022			
33	Count TTL Subtations with Transformers	311			
34	Count TTL Substations without Transformers	37			
35	Count TTL Substations	348			
36	Count TTL Spares	38			
37					
38					
39	Spare Transformers				
40	Canistota Junc-2741803	N/A	25.00	13.00	

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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	Chanarambie-TB80229802	N/A	115.00	35.00	14.00
2	Clarks Grove-8975520	N/A	69.00	7.50	
3	Falls Sub-D-561747	N/A	69.00	14.00	
4	Falls Sub-P660522	N/A	69.00	14.00	
5	Hugo Trg Ctr-242601941	N/A	115.00	14.00	
6	Inver Hills sub-10075845-001	N/A	345.00	115.00	35.00
7	Linde-9157699	N/A	115.00	14.00	
8	MGRV-1174820415	N/A	69.00	14.00	
9	MGRV-13915/1	N/A	115.00	14.00	
10	MGRV-249834	N/A	69.00	14.00	
11	MGRV-249866	N/A	69.00	14.00	
12	MGRV-4089204	N/A	14.00	5.00	
13	MGRV-48042MR002UZA186B	N/A	115.00	69.00	14.00
14	MGRV-6993529	N/A	69.00	5.00	
15	MGRV-8779073	N/A	345.00	115.00	35.00
16	MGRV-9F1025	N/A	69.00	14.00	
17	MGRV-C184245	N/A	69.00	14.00	
18	MGRV-F80331214	N/A	115.00	14.00	
19	MGRV-F8080	N/A	115.00	14.00	
20	MGRV-F8138	N/A	115.00	14.00	
21	MGRV-GT-3547	N/A	69.00	14.00	
22	MGRV-L252825C	N/A	115.00	14.00	
23	MGRV-L71020651212	N/A	115.00	14.00	
24	MGRV-TP80240801	N/A	161.00	115.00	14.00
25	MGRV-TP80279701	N/A	345.00	161.00	14.00
26	MGRV-TP80306401	N/A	230.00	115.00	14.00
27	MGRV-WT02255	N/A	345.00	115.00	35.00
28	MGRV-WT02258	N/A	115.00	69.00	13.00
29	Minn Valley-2621682	N/A	69.00	25.00	3.00
30	Minn Valley-5063761	N/A	230.00	115.00	15.00
31	Minn Valley-5069576	N/A	230.00	115.00	15.00
32	Minn Valley-6600565	N/A	230.00	115.00	15.00
33	Paynsville Transmission-A4555T	N/A	115.00	69.00	13.00
34	Paynsville Transmission-A4557T	N/A	115.00	69.00	13.00
35	Portal Pipeline (Minot)-4088687	N/A	14.00	2.50	
36	Siemens(Mexico)-T040N00142701	N/A	115.00	35.00	
37	SPX-WT-03820	N/A	230.00	115.00	14.00
38					
39					
40					

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	1					1
14	1					2
70	1					3
70	1					4
25	1					5
25	1					6
47	1					7
47	1					8
11	1					9
6	1					10
70	1					11
70	1					12
70	1					13
2	3					14
7	1					15
14	1					16
70	1					17
70	1					18
70	1					19
70	1					20
6	1					21
448	1					22
25	1					23
14	1					24
14	1					25
14	1					26
28	1					27
25	1					28
48	1					29
48	1					30
28	1					31
7	1					32
5	1					33
4	1					34
14	1					35
14	1					36
3	1					37
9	1					38
25	1					39
25	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
336	1					1
336	1					2
47	1					3
112	1					4
448	1					5
448	1					6
25	1					7
25	1					8
3	3					9
6	1					10
1	1					11
6	1					12
120	1					13
120	1					14
28	1					15
11	1					16
2	1					17
8	1					18
3	3					19
112	1					20
112	1					21
11	1					22
14	1					23
14	1					24
70	1					25
70	1					26
50	2					27
47	1					28
47	1					29
1	1					30
47	1					31
50	1					32
20	1					33
23	1					34
7	1					35
120	1					36
120	1					37
120	1					38
50	1					39
50	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
37	1					1
70	1					2
47	1					3
448	1					4
448	1					5
1203	3					6
1203	3					7
7	1					8
14	1					9
2	1					10
7	1					11
11	1					12
11	1					13
112	1					14
187	1					15
28	1					16
47	1					17
672	1					18
672	1					19
47	1					20
47	1					21
14	1					22
14	1					23
47	1					24
47	1					25
28	1					26
10	3					27
28	1					28
25	1					29
22	1					30
14	1					31
14	1					32
7	1					33
6	1					34
63	1					35
63	1					36
63	1					37
28	1					38
28	1					39
	2					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
5	1					2
14	1					3
11	1					4
8	1					5
47	1					6
70	1					7
7	1					8
20	1					9
28	1					10
5	1					11
47	1					12
47	1					13
47	1					14
11	1					15
28	1					16
28	1					17
53	1					18
1	1					19
47	1					20
47	1					21
51	1					22
448	1					23
448	1					24
2	1					25
70	1					26
70	1					27
70	1					28
70	1					29
70	1					30
73	1					31
25	1					32
70	1					33
47	1					34
448	1					35
2	3					36
	3					37
19	1					38
11	1					39
14	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
63	1					1
63	1					2
22	1					3
14	1					4
14	1					5
11	1					6
120	1					7
120	1					8
47	1					9
11	1					10
28	1					11
84	1					12
84	1					13
84	1					14
84	1					15
70	1					16
3	1					17
168	1					18
70	1					19
7	1					20
70	1					21
70	1					22
2	1					23
4	1					24
28	1					25
28	1					26
5	1					27
3	1					28
112	1					29
28	1					30
70	1					31
47	1					32
70	1					33
28	1					34
28	1					35
14	1					36
5	1					37
28	1					38
28	1					39
47	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
47	1					1
47	1					2
47	1					3
47	1					4
47	1					5
70	1					6
25	1					7
47	1					8
2	1					9
11	1					10
3	1					11
70	1					12
70	1					13
28	1					14
28	1					15
2	3					16
2	1					17
336	1					18
3	1					19
3	1					20
70	1					21
47	1					22
25	1					23
28	1					24
14	1					25
70	1					26
70	1					27
47	1					28
47	1					29
47	1					30
47	1					31
6	1					32
6	1					33
63	1					34
63	1					35
1	1					36
672	1					37
14	1					38
11	1					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1					1
3	1					2
7	1					3
47	1					4
47	1					5
47	1					6
47	1					7
47	1					8
47	1					9
47	1					10
50	1					11
448	1					12
450	1					13
16	1					14
1	1					15
74	1					16
14	1					17
4	1					18
28	1					19
47	1					20
47	1					21
120	1					22
15	1					23
11	1					24
4	1					25
28	1					26
70	1					27
336	1					28
70	1					29
112	1					30
112	1					31
14	1					32
9	1					33
47	1					34
47	1					35
70	1					36
47	1					37
70	1					38
50	1					39
50	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	1					1
29	1					2
29	1					3
11	1					4
11	1					5
47	1					6
47	1					7
12	1					8
28	1					9
52	1					10
14	1					11
70	1					12
270	1					13
47	1					14
47	1					15
70	1					16
70	1					17
7	1					18
187	1					19
187	1					20
6	1					21
4	1					22
25	1					23
70	1					24
47	1					25
3	1					26
6	1					27
14	1					28
5	1					29
4	1					30
70	1					31
70	1					32
70	1					33
2	1					34
3	1					35
63	1					36
72	1					37
70	1					38
70	1					39
28	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
28	1					1
2	1					2
8	1					3
14	1					4
187	1					5
187	1					6
47	1					7
47	1					8
6	1					9
5	1					10
336	1					11
345	1					12
7	1					13
70	1					14
70	1					15
47	1					16
14	1					17
5	1					18
28	1					19
28	1					20
3	2					21
47	1					22
47	1					23
120	1					24
120	1					25
672	1					26
672	1					27
47	1					28
47	1					29
5	1					30
5	1					31
672	1					32
47	1					33
47	1					34
50	1					35
28	1					36
17	1					37
28	1					38
47	1					39
47	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
47	1					1
47	1					2
28	1					3
70	1					4
70	1					5
47	1					6
47	1					7
50	1					8
450	3					9
450	3					10
70	1					11
70	1					12
28	1					13
336	1					14
14	1					15
7	1					16
7	1					17
14	1					18
9	1					19
6	1					20
25	1					21
25	1					22
15	1					23
224	1					24
70	1					25
70	1					26
336	1					27
336	1					28
336	1					29
28	1					30
448	1					31
50	1					32
50	1					33
3	1					34
91	1					35
91	1					36
91	1					37
47	1					38
20	1					39
47	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
336	1					1
448	1					2
448	1					3
28	1					4
28	1					5
7	1					6
7	1					7
14	1					8
28	1					9
5	1					10
47	1					11
47	1					12
25	1					13
25	1					14
8	1					15
47	1					16
47	1					17
47	1					18
47	1					19
70	1					20
5	1					21
4	3					22
7	1					23
28	1					24
7	1					25
70	1					26
70	1					27
25	1					28
28	1					29
14	1					30
70	1					31
70	1					32
672	1					33
672	1					34
	1					35
112	1					36
336	1					37
28	1					38
28	1					39
448	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
187	1					1
187	1					2
28	1					3
28	1					4
28	1					5
28	1					6
14	1					7
47	1					8
47	1					9
53	1					10
47	1					11
187	1					12
1	1					13
74	1					14
5	1					15
7	1					16
6	1					17
28	1					18
28	1					19
70	1					20
70	1					21
63	1					22
1	3					23
187	1					24
336	1					25
448	1					26
448	1					27
5	1					28
5	1					29
42	1					30
42	1					31
14	1					32
4	1					33
7	1					34
70	1					35
70	1					36
70	1					37
70	1					38
5	1					39
6	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
47	1					1
47	1					2
47	1					3
47	1					4
11	1					5
70	1					6
70	1					7
10	3					8
10	3					9
10	3					10
10	3					11
10	3					12
10	3					13
47	1					14
47	1					15
47	1					16
672	1					17
672	1					18
4	1					19
5	1					20
5	1					21
70	1					22
70	1					23
70	1					24
70	1					25
70	1					26
70	1					27
28	1					28
1	1					29
8	1					30
73	1					31
3	1					32
11	1					33
20	1					34
22	1					35
10	1					36
2	3					37
70	1					38
14	1					39
28	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
7	1					2
11	1					3
14	1					4
2	1					5
4	1					6
4	1					7
4	1					8
5	1					9
11	1					10
11	1					11
70	1					12
70	1					13
28	1					14
112	1					15
112	1					16
22	1					17
7	1					18
28	1					19
112	1					20
112	1					21
70	1					22
73	1					23
70	1					24
70	1					25
70	1					26
70	1					27
70	1					28
70	1					29
70	1					30
70	1					31
70	1					32
112	1					33
70	1					34
70	1					35
70	1					36
70	1					37
	2					38
8	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
8	1					1
28	1					2
70	1					3
70	1					4
70	1					5
448	1					6
448	1					7
70	1					8
70	1					9
70	1					10
22	1					11
22	1					12
25	1					13
11	1					14
6	1					15
5	1					16
47	1					17
47	1					18
28	1					19
28	1					20
120	1					21
120	1					22
14	1					23
11	1					24
11	1					25
4	1					26
14	1					27
45022	631					28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
5		1				40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
120		1				1
2		1				2
28		1				3
28		1				4
14		1				5
672		1				6
50		1				7
7		1				8
52		1				9
4		1				10
4		1				11
5		1				12
70		1				13
11		1				14
448		1				15
11		1				16
11		1				17
74		1				18
53		1				19
74		1				20
14		1				21
47		1				22
28		1				23
187		1				24
336		1				25
336		1				26
672		1				27
112		1				28
5		1				29
50		1				30
50		1				31
112		1				32
47		1				33
47		1				34
5		1				35
120		1				36
336		1				37
						38
						39
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	04/18/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Interchange agreement	NSP-Wisconsin	557 and 565	157,872,222
3	Receipts from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	-805,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	
5	Contribution of Capital	Xcel Energy Inc.	207	-108,751,434
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	-479,000,000
7	Company labor, benefits, and related payments	NSP-Wisconsin	see note	239,250
8	Transformer	NSP-Wisconsin	107	331,595
9				
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19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Interchange agreement	NSP-Wisconsin	456 and 456.1	-473,725,812
22	Company labor, benefits, and related payments	NSP-Wisconsin	see note	-11,520,824
23	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	564,000,000
24	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	805,000,000
25	Dividends on Common Stock	Xcel Energy Inc.	215/216	456,136,375
26	Vehicle and equipment use	NSP-Wisconsin	see note	-3,856,556
27				
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Schedule Page: 429 Line No.: 2 Column: c

557	$ 61,092,628
565	96,779,594
	$ 157,872,222

Schedule Page: 429 Line No.: 4 Column: c

Service Function Group	FERC Group	Total
Accounting, Financial Reporting & Taxes	107-CWIP	168,705
	408-409-Taxes	1,727,537
	417-421-Other Income	(150,678)
	426.1-426.5-Other Income Deductions	15,359
	427-432-Interest Charges	5,431
	500-514-Steam Power Generation	41,434
	517-532-Nuclear Power Generation	120
	546-557-Other Power Generation	179,484
	560-573-Transmission Expenses	26,251
	580-598-Distribution Expenses	38,803
	710-742-Manufactured Gas Production	12,567
	800-813-Other Gas Supply Expenses	41,744
	850-870-Transmission Expenses	33
	871-893-Distribution Expenses	19,178
	920-935-Administrative and General Expense	25,596,494
Accounting, Financial Reporting & Taxes Total		27,722,462
Aviation Services	408-409-Taxes	29,697
	426.1-426.5-Other Income Deductions	443
	920-935-Administrative and General Expense	2,496,230
Aviation Services Total		2,526,370
Business Systems	107-CWIP	76,292,682
	108-Accum Dep	8,617
	408-409-Taxes	1,938,327

	426.1-426.5-Other Income Deductions	43,936
	500-514-Steam Power Generation	1,174,478
	517-532-Nuclear Power Generation	5,028,777
	535-545-Hydraulic Power Generation	4,667
	546-557-Other Power Generation	377,320
	560-573-Transmission Expenses	6,099,573
	580-598-Distribution Expenses	1,945,550
	800-813-Other Gas Supply Expenses	125,357
	814-837-Underground Storage Expenses	845
	840-843-Other Storage Expense	4,577
	850-870-Transmission Expenses	(66,671)
	871-893-Distribution Expenses	1,197,530
	901-905-Customer Accounts Expenses	5,525,436
	908-910-Customer Service and Informational Expenses	22,709
	920-935-Administrative and General Expense	124,169,278
Business Systems Total		223,892,988
Claims Services	408-409-Taxes	32,080
	908-910-Customer Service and Informational Expenses	1,432
	920-935-Administrative and General Expense	634,013
Claims Services Total		667,525
Corporate Communications	181-190-Deferred Debits	2,415,325
	252-283-Deferred Credits	358
	408-409-Taxes	193,301
	426.1-426.5-Other Income Deductions	5,138,385
	546-557-Other Power Generation	852,855
	560-573-Transmission Expenses	299
	710-742-Manufactured Gas Production	9,608
	901-905-Customer Accounts Expenses	376
	908-910-Customer Service and Informational Expenses	472,619

	920-935-Administrative and General Expense	3,535,091
Corporate Communications Total		12,618,217
Corporate Strategy & Business Development	408-409-Taxes	81,921
	426.1-426.5-Other Income Deductions	19,585
	908-910-Customer Service and Informational Expenses	1,956
	920-935-Administrative and General Expense	1,514,380
Corporate Strategy & Business Development Total		1,617,842
Customer Service	107-CWIP	2,770
	108-Accum Dep	189
	181-190-Deferred Debits	1,387,547
	252-283-Deferred Credits	583,941
	408-409-Taxes	868,405
	426.1-426.5-Other Income Deductions	5,741
	580-598-Distribution Expenses	253
	901-905-Customer Accounts Expenses	18,547,672
	908-910-Customer Service and Informational Expenses	317,278
	920-935-Administrative and General Expense	3,335,746
Customer Service Total		25,049,542
Employee Communications	408-409-Taxes	16,929
	426.1-426.5-Other Income Deductions	365
	920-935-Administrative and General Expense	676,306
Employee Communications Total		693,600
Energy Delivery - Engineering/Design	107-CWIP	24,580,370
	108-Accum Dep	476,489
	181-190-Deferred Debits	(17,662)
	408-409-Taxes	1,001,572
	426.1-426.5-Other Income Deductions	24,332
	500-514-Steam Power Generation	8,541

	517-532-Nuclear Power Generation	11,084
	535-545-Hydraulic Power Generation	3,858
	546-557-Other Power Generation	1,149
	560-573-Transmission Expenses	6,177,634
	580-598-Distribution Expenses	1,424,669
	710-742-Manufactured Gas Production	4,293
	850-870-Transmission Expenses	925,648
	871-893-Distribution Expenses	219,459
	901-905-Customer Accounts Expenses	300
	908-910-Customer Service and Informational Expenses	1,791
	920-935-Administrative and General Expense	3,783,031
Energy Delivery - Engineering/Design Total		38,626,558
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	1,335,570
	108-Accum Dep	752
	408-409-Taxes	250,575
	426.1-426.5-Other Income Deductions	18,788
	500-514-Steam Power Generation	157
	517-532-Nuclear Power Generation	4,627
	546-557-Other Power Generation	155
	560-573-Transmission Expenses	4,063,316
	580-598-Distribution Expenses	4,910,606
	710-742-Manufactured Gas Production	13,298
	750-769-Natural Gas Production	9,281
	814-837-Underground Storage Expenses	10,711
	840-843-Other Storage Expense	543,059
	844-847-Liquified Natural Gas Terminaling Expenses	70,197

	850-870-Transmission Expenses	1,037,445
	871-893-Distribution Expenses	529,616
	901-905-Customer Accounts Expenses	170
	908-910-Customer Service and Informational Expenses	5,947
	920-935-Administrative and General Expense	1,619,247
Energy Delivery Construction, Operations & Maintenance (COM) Total		14,423,517
Energy Markets - Fuel Procurement	107-CWIP	8,793
	408-409-Taxes	52,132
	500-514-Steam Power Generation	761,293
	546-557-Other Power Generation	91,779
	560-573-Transmission Expenses	938
	800-813-Other Gas Supply Expenses	132,916
	920-935-Administrative and General Expense	492,484
Energy Markets - Fuel Procurement Total		1,540,335
Energy Markets Regulated Trading & Marketing	107-CWIP	22
	408-409-Taxes	378,653
	426.1-426.5-Other Income Deductions	19,876
	500-514-Steam Power Generation	487
	517-532-Nuclear Power Generation	553
	535-545-Hydraulic Power Generation	2,389
	546-557-Other Power Generation	4,503,131
	560-573-Transmission Expenses	510,722
	575.1-575.8-Regional Market Expenses	306,475
	800-813-Other Gas Supply Expenses	35,202
	908-910-Customer Service and Informational Expenses	663
	920-935-Administrative and General Expense	2,104,406

Energy Markets Regulated Trading & Marketing Total		7,862,579
Energy Supply Business Resources	107-CWIP	1,090,409
	108-Accum Dep	149,911
	181-190-Deferred Debits	(10,990)
	252-283-Deferred Credits	11,016
	408-409-Taxes	590,666
	426.1-426.5-Other Income Deductions	14,320
	500-514-Steam Power Generation	8,622,555
	517-532-Nuclear Power Generation	270,873
	535-545-Hydraulic Power Generation	30,175
	546-557-Other Power Generation	1,608,375
	560-573-Transmission Expenses	6,976
	580-598-Distribution Expenses	(1,011)
	871-893-Distribution Expenses	(678)
	908-910-Customer Service and Informational Expenses	(5,803)
	920-935-Administrative and General Expense	3,997,734
Energy Supply Business Resources Total		16,374,528
Energy Supply Engineering & Environmental	107-CWIP	6,890,312
	108-Accum Dep	625,539
	181-190-Deferred Debits	420,160
	408-409-Taxes	292,611
	426.1-426.5-Other Income Deductions	9,471
	500-514-Steam Power Generation	1,864,723
	517-532-Nuclear Power Generation	30,051
	535-545-Hydraulic Power Generation	418,861
	546-557-Other Power Generation	231,647
	560-573-Transmission Expenses	63,609
	580-598-Distribution Expenses	98,488

	710-742-Manufactured Gas Production	125,297
	840-843-Other Storage Expense	7,998
	871-893-Distribution Expenses	7,188
	920-935-Administrative and General Expense	2,385,178
Energy Supply Engineering & Environmental Total		13,471,133
Executive Management Services	107-CWIP	4,099
	181-190-Deferred Debits	11,955
	408-409-Taxes	133,007
	426.1-426.5-Other Income Deductions	444,244
	500-514-Steam Power Generation	(15,817)
	535-545-Hydraulic Power Generation	(93)
	546-557-Other Power Generation	(20,262)
	560-573-Transmission Expenses	(79,997)
	580-598-Distribution Expenses	(4,877)
	814-837-Underground Storage Expenses	5,517
	840-843-Other Storage Expense	14,435
	850-870-Transmission Expenses	110,068
	871-893-Distribution Expenses	156,031
	908-910-Customer Service and Informational Expenses	35,830
	920-935-Administrative and General Expense	6,845,380
Executive Management Services Total		7,639,520
Facilities & Real Estate	107-CWIP	1,638,244
	108-Accum Dep	133,859
	408-409-Taxes	128,530
	426.1-426.5-Other Income Deductions	70,143
	500-514-Steam Power Generation	3,232,756
	517-532-Nuclear Power Generation	8,986,319
	535-545-Hydraulic Power Generation	34,219
	546-557-Other Power Generation	1,248,023
	560-573-Transmission Expenses	1,939,558

	575.1-575.8-Regional Market Expenses	7,506
	580-598-Distribution Expenses	2,396,062
	710-742-Manufactured Gas Production	8,626
	750-769-Natural Gas Production	368
	800-813-Other Gas Supply Expenses	4,833
	814-837-Underground Storage Expenses	2,174
	840-843-Other Storage Expense	750
	850-870-Transmission Expenses	104,079
	871-893-Distribution Expenses	754,342
	908-910-Customer Service and Informational Expenses	(3)
	920-935-Administrative and General Expense	16,611,515
Facilities & Real Estate Total		37,301,903
Finance & Treasury	107-CWIP	639,167
	108-Accum Dep	14,040
	181-190-Deferred Debits	214,918
	252-283-Deferred Credits	7,100
	408-409-Taxes	236,759
	417-421-Other Income	(441,507)
	426.1-426.5-Other Income Deductions	75,807
	427-432-Interest Charges	1,722,248
	546-557-Other Power Generation	321,122
	560-573-Transmission Expenses	(133,122)
	580-598-Distribution Expenses	(100,149)
	850-870-Transmission Expenses	(46,808)
	871-893-Distribution Expenses	(4,845)
	901-905-Customer Accounts Expenses	1,320
	920-935-Administrative and General Expense	14,907,520
Finance & Treasury Total		17,413,570
Fleet	107-CWIP	631,580

FOOTNOTE DATA

	108-Accum Dep	6,040
	500-514-Steam Power Generation	24,497
	517-532-Nuclear Power Generation	6,678
	535-545-Hydraulic Power Generation	168
	546-557-Other Power Generation	1,452
	560-573-Transmission Expenses	34,189
	580-598-Distribution Expenses	372,831
	840-843-Other Storage Expense	1,531
	850-870-Transmission Expenses	75
	871-893-Distribution Expenses	111,742
	901-905-Customer Accounts Expenses	8,283
	920-935-Administrative and General Expense	10,905
Fleet Total		1,209,971
Government Affairs	408-409-Taxes	47,033
	426.1-426.5-Other Income Deductions	504,149
	920-935-Administrative and General Expense	858,945
Government Affairs Total		1,410,127
Human Resources	107-CWIP	(22,076)
	108-Accum Dep	523
	181-190-Deferred Debits	1,442
	227-230-Other Noncurrent Liabilities	765,176
	231-245-Current and Accrued Liabilities	18,675,643
	408-409-Taxes	641,297
	426.1-426.5-Other Income Deductions	109,010
	500-514-Steam Power Generation	(148,848)

	517-532-Nuclear Power Generation	741,165
	546-557-Other Power Generation	(2,962)
	560-573-Transmission Expenses	(11,455)
	580-598-Distribution Expenses	753,658
	710-742-Manufactured Gas Production	2,229
	850-870-Transmission Expenses	428,147
	871-893-Distribution Expenses	138,456
	908-910-Customer Service and Informational Expenses	216,651
	920-935-Administrative and General Expense	20,856,096
Human Resources Total		43,144,152
Internal Audit	408-409-Taxes	63,012
	426.1-426.5-Other Income Deductions	85
	920-935-Administrative and General Expense	1,416,557
Internal Audit Total		1,479,654
Investor Relations	408-409-Taxes	17,567
	426.1-426.5-Other Income Deductions	1,178
	920-935-Administrative and General Expense	1,023,934
Investor Relations Total		1,042,679
Legal	107-CWIP	75,339
	108-Accum Dep	3,667
	181-190-Deferred Debits	294
	408-409-Taxes	323,839
	426.1-426.5-Other Income Deductions	22,291
	517-532-Nuclear Power Generation	259,243
	535-545-Hydraulic Power Generation	576
	546-557-Other Power Generation	285
	560-573-Transmission Expenses	23,956

	710-742-Manufactured Gas Production	110,267
	871-893-Distribution Expenses	1
	908-910-Customer Service and Informational Expenses	105
	920-935-Administrative and General Expense	7,184,695
Legal Total		8,004,558
Marketing & Sales	181-190-Deferred Debits	8,968,147
	252-283-Deferred Credits	64,769
	408-409-Taxes	138,205
	426.1-426.5-Other Income Deductions	5,887
	901-905-Customer Accounts Expenses	93
	908-910-Customer Service and Informational Expenses	1,581,258
	920-935-Administrative and General Expense	5,985,871
Marketing & Sales Total		16,744,230
Payment & Reporting	107-CWIP	1,433
	408-409-Taxes	33,591
	920-935-Administrative and General Expense	1,091,410
Payment & Reporting Total		1,126,434
Payroll	107-CWIP	(27,852)
	108-Accum Dep	(641)
	181-190-Deferred Debits	(9,372)
	252-283-Deferred Credits	(327)
	408-409-Taxes	56,851
	426.1-426.5-Other Income Deductions	(1,319)
	560-573-Transmission Expenses	6,009
	580-598-Distribution Expenses	3,906
	850-870-Transmission Expenses	1,853
	871-893-Distribution Expenses	207
	920-935-Administrative and General Expense	914,583

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) X An Original (2) __ A Resubmission	04/18/2019	2018/Q4

FOOTNOTE DATA

Payroll Total		943,898
Rates & Regulation	181-190-Deferred Debits	5,131
	408-409-Taxes	130,145
	426.1-426.5-Other Income Deductions	387
	546-557-Other Power Generation	2,278
	560-573-Transmission Expenses	4,870
	580-598-Distribution Expenses	43,215
	710-742-Manufactured Gas Production	174
	850-870-Transmission Expenses	1
	871-893-Distribution Expenses	15,583
	908-910-Customer Service and Informational Expenses	1,182
	920-935-Administrative and General Expense	2,272,494
Rates & Regulation Total		2,475,460
Receipts Processing	408-409-Taxes	36,544
	426.1-426.5-Other Income Deductions	1,290
	901-905-Customer Accounts Expenses	380,611
	920-935-Administrative and General Expense	292,781
Receipts Processing Total		711,226
Supply Chain	107-CWIP	4,423,457
	108-Accum Dep	129,131
	130-176-Current and Accrued Assets	1,189
	181-190-Deferred Debits	(21,005)
	231-245-Current and Accrued Liabilities	12,457
	252-283-Deferred Credits	121
	408-409-Taxes	5,415
	426.1-426.5-Other Income Deductions	77,750

	500-514-Steam Power Generation	275,559
	517-532-Nuclear Power Generation	992,097
	535-545-Hydraulic Power Generation	549
	546-557-Other Power Generation	122,150
	560-573-Transmission Expenses	120,938
	575.1-575.8-Regional Market Expenses	25
	580-598-Distribution Expenses	355,608
	710-742-Manufactured Gas Production	543
	750-769-Natural Gas Production	4
	800-813-Other Gas Supply Expenses	138
	840-843-Other Storage Expense	2,829
	844-847-Liquified Natural Gas Terminaling Expenses	4,134
	850-870-Transmission Expenses	32,546
	871-893-Distribution Expenses	90,408
	901-905-Customer Accounts Expenses	231,741
	908-910-Customer Service and Informational Expenses	4,326
	911-916-Sales Expense	18
	920-935-Administrative and General Expense	197,056
Supply Chain Total		7,059,184
Grand Total		534,793,762

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107	$ 144,965
108	9,976
184	775
501	1,886
511	385
512	158
538	5,525
543	4,693

544	33,468
545	163
549	122
560	94
562	1,798
563	(444)
566	4,650
571	1,565
580	224
583	48
584	507
585	117
586	1,967
588	10,313
592	918
593	12,871
594	339
759	96
870	46
874	139
878	269
879	198
880	505
889	252
903	113
921	549
	$ 239,250

Schedule Page: 429 Line No.: 21 Column: c

456	$(411,234,036)
456.1	(62,491,776)
	$(473,725,812)

Schedule Page: 429 Line No.: 22 Column: c

107	$ (10,426,434)
108	(526,475)
163	(19,888)
184	(56,090)
500	(28)
501	(9,320)
511	(15,116)
512	(152,130)
513	(10,917)
514	(8,108)
543	(808)
544	(179)
552	(86,019)
553	(3,780)
56.2	(82)
563	(923)
570	(8,222)
571	(20,174)
582	(399)
583	(929)
586	(7,125)
587	(51)
588	(20,742)

592	(10,804)
593	(25,062)
594	(1,734)
596	(21)
598	(17,746)
710	(91)
844.3	(169)
847.3	(1,833)
874	(7,055)
875	(605)
878	(1,829)
879	(4,821)
880	(801)
887	(3,310)
892	(231)
893	(23)
902	(14,199)
903	(55,821)
921	(730)
	$ (11,520,824)

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107	$ (3,639,621)
108	(238,410)
514	47,721
563	(203)
570	(1,786)
571	(7,724)
584	(346)
585	(1,024)
586	(24)
587	(372)
588	(1,764)
592	(712)
593	(9,208)
596	(56)
598	(1,642)
892	(889)
902	(378)
903	(118)
	$ (3,856,556)

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