

THIS FILING IS
Item 1: ☒ An Initial (Original) Submission OR ☐ Resubmission No.



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

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

Exact Legal Name of Respondent (Company) Northern States Power Company (Minnesota)	Year/Period of Report End of: 2025/ Q4
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INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

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.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission’s Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others 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:

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

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at <https://eCollection.ferc.gov>, and according to the specifications in the Form 1 and 3-Q taxonomies.

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

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

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:

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

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.)

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

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at <https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online>.

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 <https://www.ferc.gov/general-information-0/electric-industry-forms>.

When to Submit

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

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

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

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.

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.

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).

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.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

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.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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
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.
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:

'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;

'Person' means an individual or a corporation;

'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;

'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;

"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

'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.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by 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 shall 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.

collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

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.

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.

FERC FORM NO. 1 (ED. 03-07)

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 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: 2025/ 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 Melissa L. Ostrom		06 Title of Contact Person Senior Vice President, 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) 330-5500	09 This Report is An Original / A Resubmission (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/09/2026
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 Melissa L. Ostrom	03 Signature Melissa L. Ostrom	04 Date Signed (Mo, Da, Yr) 04/09/2026
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) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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)	
	Identification	1		
	List of Schedules	2		
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		
7	Important Changes During the Year	108		
8	Comparative Balance Sheet	110		
9	Statement of Income for the Year	114		
10	Statement of Retained Earnings for the Year	118		
12	Statement of Cash Flows	120		
12	Notes to Financial Statements	122		
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a		
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200		
15	Nuclear Fuel Materials	202		
16	Electric Plant in Service	204		
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		
22	Materials and Supplies	227		
23	Allowances and Environmental Credits	228		
24	Extraordinary Property Losses	230a	N/A	
25	Unrecovered Plant and Regulatory Study Costs	230b		
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		
31	Other Paid-in Capital	253		

32	Capital Stock Expense	254b	N/A
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
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 (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
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	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
63.1	Renewable Generating Plant Statistics	404	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	N/A
66.1	Energy Storage Operations (Large Plants)	414	N/A
66.2	Energy Storage Operations (Small Plants)	419	N/A
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	

69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☒ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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. Melissa Ostrom 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. State of Incorporation: MN Date of Incorporation: 2000-03-09 Incorporated Under Special Law: N/A			
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. (a) Name of Receiver or Trustee Holding Property of the Respondent: (b) Date Receiver took Possession of Respondent Property: (c) Authority by which the Receivership or Trusteeship was created: (d) Date when possession by receiver or trustee ceased:			
4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated. Northern States Power Company - Minnesota (NSPM) is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. The operations of NSPM are within the states of Minnesota, North Dakota, and 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 (2) ☒ No			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
CONTROL OVER RESPONDENT			
1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.			
Northern States Power Co. (a Minnesota corporation) is a wholly-owned subsidiary of Xcel Energy, Inc.			

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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		
4	Crowned Ridge Interconnection Co.	Transmission system interconnection	50		

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OFFICERS					
1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions. 2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.					
Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	Chairman, Chief Executive Officer	Robert C. Frenzel	560,894	2025-01-01	2025-12-31
2	Senior Vice President, Chief Nuclear Officer	Christopher Church	505,000	2025-01-01	2025-12-31
3	(a) Executive Vice President, Chief Legal and Compliance Officer	Ryan Long	389,057	2025-01-01	2025-12-31
4	Executive Vice President, Chief Financial Officer	Brian J. Van Abel	324,932	2025-01-01	2025-12-31
5	Executive Vice President, Group President, Utilities and Chief Customer Officer	Amanda Rome	299,788	2025-01-01	2025-12-31
6	Senior Vice President, Chief Human Resources Officer	Patricia Correa	275,389	2025-01-01	2025-12-31
7	Senior Vice President, Controller	Melissa Ostrom	160,209	2025-01-01	2025-12-31
8	Executive Vice President, Chief Generation Officer	Scott Sharp	151,170	2025-05-01	2025-12-31
9	Executive Vice President, Chief Delivery Officer	Michael Lamb	150,861	2025-05-01	2025-12-31
10	Vice President, Corporate Secretary and Securities	Amy L. Schneider	133,454	2025-01-01	2025-12-31
11	Vice President, Treasurer	Todd Wehner	129,586	2025-01-01	2025-12-31
12	Executive Vice President, Chief Legal and Compliance Officer	Rob Berntsen	117,955	2025-01-01	2025-06-13
13	Executive Vice President, Chief Operations Officer	Timothy J. O'Connor	102,932	2025-01-01	2025-05-01
14	President	Bria Shea	93,750	2025-10-20	2025-12-31
15	Salaries represent NSP-Minnesota's allocation of officers' salaries greater than \$50,000 for the period of time that was served as an officer for NSP-Minnesota.				

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FOOTNOTE DATA			
(a) Concept: OfficerTitle			
Ryan Long held multiple positions for NSP-Minnesota throughout 2025. From Jan. 1 through June 16, he served as President of NSP-Minnesota. Effective June 16, Mr. Long resigned as President and was elected as Executive Vice President, Chief Legal Officer and Interim President. As of Oct. 20, 2025, Mr. Long resigned as Interim President. The salary reflected on page 104 includes salary for each of these positions.			

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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), name and abbreviated titles of the directors who are officers of the respondent. 2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).					
Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)	
1	Bria Shea, President	414 Nicollet Mall, Minneapolis, MN 55401	true	false	
2	Robert C. Frenzel, Chairman and Chief Executive Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	true	
3	Brian J. Van Abel, Executive Vice President and Chief Financial Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false	
4	Amanda Rome, Executive Vice President, Group President, Utilities and Chief Customer Officer	414 Nicollet Mall, Minneapolis, MN 55401	true	false	
5	^(a) Ryan Long, President	414 Nicollet Mall, Minneapolis, MN 55401	true	false	

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FOOTNOTE DATA			
(a) Concept: NameAndTitleOfDirector			
Effective June 16, 2025, Ryan Long elected Executive Vice President, Chief Legal Officer and Interim President. Effective October 20, 2025, Ryan Long resigned as Interim President.			

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INFORMATION ON FORMULA RATES							
Does the respondent have formula rates?				☒ Yes ☐ No			
1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.							
Line No.	FERC Rate Schedule or Tariff Number (a)			FERC Proceeding (b)			
1	FERC Electric Tariff, Third Revised Volume No. 1 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER07-1415-000 - Order Granting Incentives, and Accepting Proposed Rate Formula Modifications, Subject to Conditions, Issued December 21, 2007, Accession No. 20071221-3012			
2	FERC Electric Tariff, Fourth Revised Volume No. 1 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER10-541-000 - Approval of Tariff Revisions to Attachment O-NSP, Issued February 26, 2010, Accession No. 20100226-3041			
3	FERC Electric Tariff updated effective 01-01-2012 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER12-297-000 - Approval of Tariff Revisions to Attachment O-NSP, Issued December 21, 2011, Accession No. 20111221-3033			
4	FERC Electric Tariff updated effective 01-01-2013 (Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER13-674-000/001/002 Approval of Tariff Revisions to Attachment O-NSP, Issued March 20, 2013, Accession No. 20130320-3014			
5	FERC Electric Tariff updated effective 11-19-2013 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP, Attachment GG-NSP; & Attachment MM)			ER14-421-000/001 Approval of Tariff Revisions to Attachment O-NSP, Issued March 11, 2014, Accession No. 20140311-3041			
6	FERC Electric Tariff updated effective 01-06-2015 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER15-358-000 Approval of Tariff Revisions to Attachment O-NSP, Issued January 6, 2015, Accession No. 20150105-3035			
7	FERC Electric Tariff updated effective 01-01-2016 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER16-197-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 30, 2015, Accession No. 20151230-3075			
8	FERC Electric Tariff updated effective 01-01-2017 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER17-305-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 30, 2016, Accession No. 20161230-3022			
9	FERC Electric Tariff updated effective 12-01-2017 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER18-12-000 Approval of Tariff Revisions to Attachment O-NSP, Issued November 29, 2017, Accession No. 20171129-3095			
10	FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER18-2322-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 20, 2018, Accession No. 20181220-3030			
11	FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER19-249-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 20, 2018, Accession No. 20181220-3011			
12	FERC Electric Tariff updated effective 07-01-2019 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER19-2295-000 Approval of Tariff Revisions to Attachment O-NSP, Issued August 23, 2019 Accession No. 20190823-3078			
13	FERC Electric Tariff updated effective 01-01-2021 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER21-200-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 11, 2020 Accession No. 20201211-3012			
14	FERC Electric Tariff updated effective 01-01-2021 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER21-262-000 Approval of Tariff Revisions to Attachment O-NSP, Issued December 11, 2020 Accession No. 20201211-3016			
15	FERC Electric Tariff updated effective 09-26-2022 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER22-1602-000 Approval of Tariff Revisions to Attachment O-NSP, Issued May 10, 2022 Accession No. 20220510-3053			
16	FERC Electric Tariff updated effective 06-01-2023 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)			ER23-1532-000 Approval of Tariff Revisions to Attachment O-NSP, Issued May 19, 2023 Accession No. 20230519-3029			
17	FERC Electric Tariff updated effective 01-01-2025 (Midcontinent Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment GG-NSP)			ER25-323-000 Approval of Tariff Revisions to Attachment GG-NSP, Issued November 1, 2024 Accession No. 20241101-5066			

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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)?				☒ Yes ☐ No				
If yes, provide a listing of such filings as contained on the Commission's eLibrary website.								
Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)		Formula Rate FERC Rate Schedule Number or Tariff Number (e)		
1	20170308-5088	03/08/2017	ER17-1120-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2017 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
2	20180313-5128	03/13/2018	ER18-1004-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2018 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
3	20190314-5169	03/14/2019	ER19-1310-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2019 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
4	20200319-5161	03/19/2020	ER20-1354-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2020 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
5	20210315-5372	03/15/2021	ER21-1439-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2021 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
6	20220315-5085	03/15/2022	ER22-1320-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2022 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
7	20230315-5198	03/15/2023	ER23-1395-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2023 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
8	20240315-5277	03/15/2024	ER24-1525-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2024 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		
9	20250314-5363	03/14/2025	ER25-1723-000	Annual Informational Attachment O filing of NSP-Minnesota and NSP-Wisconsin		FERC Electric Tariff updated effective 01-01-2025 (Midcontinent Independent System Operator, Inc. Open Access Transmission and Energy Markets Tariff, Attachment O-NSP)		

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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). (a)	Schedule (b)	Column (c)	Line No. (d)			
1	110-111	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)	a	2			
4	216	Construction Work in Progress- Electric (Acct 107)	a	233			
5	219	Accum Prov for Depr- Elec Utility Plant (Acct 108)	c	20-28			
6	227	Materials and Supplies	a	17			
7	227	Materials and Supplies	b, c	5			
8	232	Other Regulatory Assets	f	26			
9	234	Accumulated Deferred Income Taxes (Acct 190)	c	8			
10	266-267	Accum. Deferred Investment Tax Credits (Acct 255)	h	8			
11	269	Other Deferred Credits (Acct 253)	d, e	17			
12	269	Other Deferred Credits (Acct 253)	a	23			
13	272-273	Accumulated Deferred Income Taxes (Acct 281)	k	4			
14	274-275	Accumulated Deferred Income Taxes (Acct 282)	k	2			
15	276-277	Accumulated Deferred Income Taxes (Acct 283)	k	9			
16	278	Other Regulatory Liabilities	f	22			
17	300	Electric Operating Revenues (Acct 400)	b	19			
18	310-311	Sales for Resale (Acct 447)	a	33			
19	320-323	Electric Operation and Maintenance Expenses	b	112			
20	328	Transmission of Electricity for Others	a	19			
21	356	Common Utility Plant and Expenses	n/a	n/a			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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. - 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. - 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. - 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. - 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. - 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. - 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. - Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments. - State the estimated annual effect and nature of any important wage scale changes during the year. - 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. - Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 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. (Reserved.) - 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. - Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period. - 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.			
1. Franchise City, State - Utility - Expiration Cosmos, MN - Electric - January 13, 2045 Cosmos, MN - Gas - February 12, 2045 Courtland, MN - Electric - February 5, 2045 Good Thunder, MN - Electric - March 9, 2045 Hatfield, MN - Electric - February 10, 2045 Lake Elmo, MN - Electric - March 3, 2045 Lake Elmo, MN - Gas - March 3, 2045 Layfayette, MN - Electric - February 9, 2045 Mahtomedi, MN - Electric - February 3, 2045 Mahtomedi, MN - Gas - February 3, 2045 Manchester, MN - Electric - March 9, 2045 Minneapolis, MN - Electric - December 31, 2034 Vermillion, MN - Electric - January 6, 2045 Winona, MN - Gas - February 2, 2045 Chaska, MN - Electric - June 15, 2045 Hazel Run, MN - Electric - May 10, 2045 Regal, MN - Electric - April 30, 2045 Watkins, MN – Electric – July 9, 2045 St. Paul Park, MN – Electric – July 20, 2045 St. Paul Park, MN – Gas – July 20, 2045 East Grand Forks, MN – Gas – August 18, 2045 Hammond, MN – Electric – September 8, 2045 Faribault, MN – Electric – September 22, 2045 Faribault, MN – Gas - September 22, 2045 Mound, MN – Electric – December 31, 2045 Lake Lillian, MN – Electric – October 6, 2045 Hanley Falls, MN – Electric – October 8, 2045 Osakis, MN – Electric – October 12, 2045 Roseville, MN – Electric – November 23, 2045 Roseville, MN – Gas - November 23, 2045 Roscoe, MN – Electric – December 3, 2045			
2. Acquisitions None.			
3. Purchase or sale of an operating unit or system None.			
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 assumptions of liabilities See Note 5 of the Financial Statements on Page 123 for disclosure regarding short-term borrowings, long-term debt and other financing activities.			
7. Changes in articles of incorporation or amendments to charter. None.			
8. Wage scale changes Certain Union Employees — 3.00 percent increase effective Jan. 1, 2025. Certain Union Employees — 3.00 percent increase effective June 15, 2025. Certain Union Employees — 3.00 percent increase effective August 1, 2025. Non-Union Employees — Merit based increase of 3.00 percent, effective March 16, 2025.			
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 See Note 11 of the Financial Statements on Page 123 for disclosures regarding related party transactions.			

12. Important Changes See Notes to the Financial Statements on Page 123 for all other important changes.
13. Changes in officers, directors, major security holders and voting powers Effective May 1, 2025, Timothy O'Connor resigned as Executive Vice President, Chief Operations Officer Effective May 1, 2025, Michael Lamb elected as Executive Vice President, Chief Delivery Officer Effective May 1, 2025, Scott Sharp elected Executive Vice President, Chief Generation Officer Effective June 13, 2025, Rob Berntsen resigned as Executive Vice President, Chief Legal and Compliance Officer Effective June 16, 2025, Ryan Long elected Executive Vice President, Chief Legal and Compliance Officer and Interim President Effective October 20, 2025, Ryan Long resigned as Interim President Effective October 20, 2025, Bria Shea elected as President
14. Cash management programs Not applicable as proprietary capital ratio is greater than 30 percent.

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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	32,884,997,509		29,859,480,554		
3	Construction Work in Progress (107)	200	1,956,682,871		1,531,616,544		
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		34,841,680,380		31,391,097,098		
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	11,639,376,830		11,315,978,537		
6	Net Utility Plant (Enter Total of line 4 less 5)		23,202,303,550		20,075,118,561		
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	233,046,076		208,557,507		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)				66,773,660		
9	Nuclear Fuel Assemblies in Reactor (120.3)		582,595,894		557,340,356		
10	Spent Nuclear Fuel (120.4)		2,862,659,590		2,658,192,690		
11	Nuclear Fuel Under Capital Leases (120.6)						
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	3,208,198,362		3,093,699,820		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		470,103,198		397,164,393		
14	Net Utility Plant (Enter Total of lines 6 and 13)		23,672,406,748		20,472,282,954		
15	Utility Plant Adjustments (116)						
16	Gas Stored Underground - Noncurrent (117)						
17	OTHER PROPERTY AND INVESTMENTS						
18	Nonutility Property (121)		38,603,416		33,656,610		
19	(Less) Accum. Prov. for Depr. and Amort. (122)		15,183,369		13,475,444		
20	Investments in Associated Companies (123)						
21	Investment in Subsidiary Companies (123.1)	224	16,842,808		15,859,609		
23	Noncurrent Portion of Allowances and Environmental Credits	228					
24	Other Investments (124)		49,737,747		54,689,426		
25	Sinking Funds (125)						
26	Depreciation Fund (126)						
27	Amortization Fund - Federal (127)						
28	Other Special Funds (128)		3,940,354,294		3,493,594,277		
29	Special Funds (Non Major Only) (129)						
30	Long-Term Portion of Derivative Assets (175)		54,284,091		66,725,895		
31	Long-Term Portion of Derivative Assets - Hedges (176)						
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,084,638,987		3,651,050,373		
33	CURRENT AND ACCRUED ASSETS						
34	Cash and Working Funds (Non-major Only) (130)						
35	Cash (131)		5,809,859		4,437,525		
36	Special Deposits (132-134)		3,774,380		3,281,822		

37	<u>Working Fund (135)</u>		118,705	159,347
38	<u>Temporary Cash Investments (136)</u>		58,609,151	51,373,345
39	<u>Notes Receivable (141)</u>			
40	<u>Customer Accounts Receivable (142)</u>		518,090,256	503,402,450
41	<u>Other Accounts Receivable (143)</u>		112,206,361	147,275,778
42	<u>(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)</u>		38,484,328	43,602,395
43	<u>Notes Receivable from Associated Companies (145)</u>			33,000,000
44	<u>Accounts Receivable from Assoc. Companies (146)</u>		3,301,611	7,210,542
45	<u>Fuel Stock (151)</u>	227	72,808,690	81,648,991
46	<u>Fuel Stock Expenses Undistributed (152)</u>	227		
47	<u>Residuals (Elec) and Extracted Products (153)</u>	227		
48	<u>Plant Materials and Operating Supplies (154)</u>	227	260,283,162	231,709,713
49	<u>Merchandise (155)</u>	227	2,124,680	1,331,042
50	<u>Other Materials and Supplies (156)</u>	227		
51	<u>Nuclear Materials Held for Sale (157)</u>	202/227		
52	<u>Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)</u>	228	200,000	200,000
53	<u>(Less) Noncurrent Portion of Allowances and Environmental Credits</u>	228		
54	<u>Stores Expense Undistributed (163)</u>	227		
55	<u>Gas Stored Underground - Current (164.1)</u>		28,590,095	20,785,341
56	<u>Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)</u>		3,210,314	2,928,480
57	<u>Prepayments (165)</u>		29,977,535	40,901,800
58	<u>Advances for Gas (166-167)</u>			
59	<u>Interest and Dividends Receivable (171)</u>		7,465,520	2,257,102
60	<u>Rents Receivable (172)</u>		1,347,829	1,147,731
61	<u>Accrued Utility Revenues (173)</u>		316,797,728	273,564,152
62	<u>Miscellaneous Current and Accrued Assets (174)</u>		213	1,352
63	<u>Derivative Instrument Assets (175)</u>		131,924,183	103,213,684
64	<u>(Less) Long-Term Portion of Derivative Instrument Assets (175)</u>		54,284,091	66,725,895
65	<u>Derivative Instrument Assets - Hedges (176)</u>		793,683	
66	<u>(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)</u>			
67	<u>Total Current and Accrued Assets (Lines 34 through 66)</u>		1,464,665,536	1,399,501,907
68	<u>DEFERRED DEBITS</u>			
69	<u>Unamortized Debt Expenses (181)</u>		89,635,270	79,690,543
70	<u>Extraordinary Property Losses (182.1)</u>	230a		
71	<u>Unrecovered Plant and Regulatory Study Costs (182.2)</u>	230b	46,721,207	55,351,360
72	<u>Other Regulatory Assets (182.3)</u>	232	4,154,888,043	4,128,101,094
73	<u>Prelim. Survey and Investigation Charges (Electric) (183)</u>		10,504,345	4,399,957
74	<u>Preliminary Natural Gas Survey and Investigation Charges 183.1)</u>			
75	<u>Other Preliminary Survey and Investigation Charges (183.2)</u>			
76	<u>Clearing Accounts (184)</u>			

77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	32,742,231	37,542,020
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		8,275,579	9,054,665
82	Accumulated Deferred Income Taxes (190)	234	1,368,121,254	1,458,301,719
83	Unrecovered Purchased Gas Costs (191)		44,871,794	76,107,452
84	Total Deferred Debits (lines 69 through 83)		5,755,759,723	5,848,548,810
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		34,977,470,994	31,371,384,044

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FOOTNOTE DATA			
(a) Concept: UtilityPlant			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			
(b) Concept: Prepayments			
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.			
(c) Concept: AccumulatedDeferredIncomeTaxes			
Refer to FERC page 232 for NSPM's regulatory asset related to nonplant excess ADIT.			
(d) Concept: UtilityPlant			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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	10,000		10,000		
3	Preferred Stock Issued (204)	250					
4	Capital Stock Subscribed (202, 205)						
5	Stock Liability for Conversion (203, 206)						
6	Premium on Capital Stock (207)		479,282,529		479,282,529		
7	Other Paid-In Capital (208-211)	253	6,572,882,690		5,920,268,234		
8	Installments Received on Capital Stock (212)	252					
9	(Less) Discount on Capital Stock (213)	254					
10	(Less) Capital Stock Expense (214)	254b					
11	Retained Earnings (215, 215.1, 216)	118	3,331,965,984		2,870,730,559		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	11,110,764		10,127,458		
13	(Less) Reacquired Capital Stock (217)	250					
14	Noncorporate Proprietorship (Non-major only) (218)						
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(4,137,065)		(8,019,595)		
16	Total Proprietary Capital (lines 2 through 15)		10,391,114,902		9,272,399,185		
17	LONG-TERM DEBT						
18	Bonds (221)	256	8,046,899,000		7,984,000,000		
19	(Less) Reacquired Bonds (222)	256					
20	Advances from Associated Companies (223)	256	953,101,000		166,000,000		
21	Other Long-Term Debt (224)	256	1,740,683		2,032,176		
22	Unamortized Premium on Long-Term Debt (225)						
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		50,225,862		49,452,185		
24	Total Long-Term Debt (lines 18 through 23)		8,951,514,821		8,102,579,991		
25	OTHER NONCURRENT LIABILITIES						
26	Obligations Under Capital Leases - Noncurrent (227)		1,324,297,088		316,531,702		
27	Accumulated Provision for Property Insurance (228.1)						
28	Accumulated Provision for Injuries and Damages (228.2)						
29	Accumulated Provision for Pensions and Benefits (228.3)		85,867,000		127,399,436		
30	Accumulated Miscellaneous Operating Provisions (228.4)						
31	Accumulated Provision for Rate Refunds (229)		16,105,415		3,172,988		
32	Long-Term Portion of Derivative Instrument Liabilities		66,748,300		76,544,979		
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges						
34	Asset Retirement Obligations (230)		3,214,587,188		3,073,005,377		
35	Total Other Noncurrent Liabilities (lines 26 through 34)		4,707,604,991		3,596,654,482		

36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		220,000,000	195,000,000
38	Accounts Payable (232)		695,017,176	644,799,783
39	Notes Payable to Associated Companies (233)		74,000,000	
40	Accounts Payable to Associated Companies (234)		108,734,594	100,939,378
41	Customer Deposits (235)		27,642,380	30,960,151
42	Taxes Accrued (236)	262	240,247,630	220,546,958
43	Interest Accrued (237)		82,815,716	90,432,205
44	Dividends Declared (238)		103,372,375	80,177,000
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		48,428,016	46,159,875
48	Miscellaneous Current and Accrued Liabilities (242)		9,642,972	9,022,701
49	Obligations Under Capital Leases-Current (243)		43,891,790	97,162,928
50	Derivative Instrument Liabilities (244)		89,680,669	107,290,057
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		66,748,300	76,544,979
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,676,725,018	1,545,946,057
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		19,181,668	17,023,097
57	Accumulated Deferred Investment Tax Credits (255)	266	11,426,870	12,739,706
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	363,045,011	338,795,040
60	Other Regulatory Liabilities (254)	278	4,948,261,929	4,805,645,856
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	16,225,633	17,911,074
63	Accum. Deferred Income Taxes-Other Property (282)		3,449,667,567	3,096,333,381
64	Accum. Deferred Income Taxes-Other (283)		442,702,584	565,356,175
65	Total Deferred Credits (lines 56 through 64)		9,250,511,262	8,853,804,329
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		34,977,470,994	31,371,384,044

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: ObligationsUnderCapitalLeaseNoncurrent			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			
See Note 9 to the Financial Statements on page 123 for leasing disclosures.			
(b) Concept: ObligationsUnderCapitalLeasesCurrent			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			
See Note 9 to the Financial Statements on page 123 for leasing disclosures.			
(c) Concept: AccumulatedDeferredIncomeTaxesOther			
Refer to FERC Page 278 for NSPM's regulatory liability related to nonplant excess ADIT			
(d) Concept: ObligationsUnderCapitalLeaseNoncurrent			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			
See Note 9 to the Financial Statements on page 123 for leasing disclosures.			
(e) Concept: ObligationsUnderCapitalLeasesCurrent			
Includes operating leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000.			
See Note 9 to the Financial Statements on page 123 for leasing disclosures.			

[illegible]

[illegible]

59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		2,039,080	4,385,020								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		89,030,076	80,416,001								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		373,019,633	345,767,911								
63	Amort. of Debt Disc. and Expense (428)		6,951,257	6,247,772								
64	Amortization of Loss on Reaquired Debt (428.1)		779,085	981,354								
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)		14,701,620	4,775,571								
68	Other Interest Expense (431)		14,170,433	36,304,624								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		36,903,241	25,563,142								
70	Net Interest Charges (Total of lines 62 thru 69)		372,718,787	368,514,090								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		903,512,230	792,840,564								
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										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		903,512,230	792,840,564								

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Sales True-up	\$ 101,724,104	\$ —
Minnesota Renewable Development Fund Rider	31,708,663	—
Theoretical Depreciation Reserve Surplus	8,842,237	—
South Dakota Infrastructure Rider	2,308,690	—
North Dakota Renewable Energy Rider	869,846	—
Sherco Unit 3 Depreciation Deferral	503,130	—
Minnesota Incentive Compensation Refund	373,035	94,656
North Dakota AGIS Deferral	206,505	—
Minnesota Gas Decoupling	—	13,051,062
Minnesota Gas Utility Infrastructure Rider	—	4,386,321
Minnesota Natural Gas Innovation Act Rider	—	3,151,508
	<u>\$ 146,536,210</u>	<u>\$ 20,683,547</u>

(b) Concept: RegulatoryCredits

	Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$ 155,903,809	\$ 1,633,667
Minnesota Transmission Cost Recovery Rider	11,651,885	—
Minnesota Electric Property Tax Tracker	7,653,885	—
Minnesota Renewable Energy Standard Rider	5,500,983	—
Minnesota Net Operating Loss	2,286,672	—
South Dakota Electric Property Tax Tracker	1,109,770	—
South Dakota Transmission Cost Recovery Rider	639,891	—
North Dakota Transmission Cost Recovery Rider	545,531	—
South Dakota Infrastructure Rider	271,297	—
Minnesota State Energy Policy Rider	8,374	—
Minnesota Gas Property Tax Tracker	—	7,325,087
	<u>\$ 185,572,097</u>	<u>\$ 8,958,754</u>

(c) Concept: LifeInsurance

Income on Company Owned Life Insurance.

(d) Concept: RegulatoryDebits

	Electric	Gas
Minnesota Renewable Development Fund Rider	\$ 38,373,757	\$ —
Minnesota Electric Property Tax Tracker	23,226,620	—
Minnesota Renewable Energy Standard Rider	11,759,866	—
Theoretical Depreciation Reserve Surplus	8,892,617	—
Minnesota Transmission Cost Recovery Rider	6,447,903	—
Minnesota Incentive Compensation Refund	4,523,334	32,479
South Dakota Infrastructure Rider	1,293,208	—
Minnesota Business Incentive and Sustainability Rider	871,192	—
Sherco Unit 3 Depreciation Deferral	503,130	—
Minnesota LED Streetlighting	120,020	—
Minnesota Gas Utility Infrastructure Rider	—	7,093,700
	<u>\$ 96,011,647</u>	<u>\$ 7,126,179</u>

(e) Concept: RegulatoryCredits

		Electric	Gas
Asset Retirement Obligation Regulatory Credits	\$	158,569,756	\$ 1,629,600
Minnesota Capacity Revenue Tracker		107,423,187	—
Minnesota Electric Capital True-up		37,218,277	—
Minnesota Electric Sales True-up		20,776,376	—
Minnesota Net Operating Loss		1,526,909	—
North Dakota AGIS Deferral		1,345,999	—
Minnesota State Energy Policy Rider		1,248,328	—
North Dakota Renewable Energy Rider		858,793	—
North Dakota Transmission Cost Recovery Rider		578,863	—
South Dakota Transmission Cost Recovery Rider		383,634	—
South Dakota Electric Property Tax Tracker		50,402	—
Minnesota Gas Decoupling		—	21,634,245
Minnesota Gas Property Tax Tracker		—	2,083,713
	\$	329,980,524	\$ 25,347,558
(f) Concept: LifeInsurance			
Income on Company Owned Life Insurance.			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
STATEMENT OF RETAINED EARNINGS				
1. Do not report Lines 49-53 on the quarterly report. 2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.				
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		2,870,652,936	2,543,350,461
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Rounding		1	
15	TOTAL Debits to Retained Earnings (Acct. 439)		1	
16	Balance Transferred from Income (Account 433 less Account 418.1)		902,528,924	780,482,475
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock (Account 438)	238	(441,293,500)	(453,180,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(441,293,500)	(453,180,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,331,888,361	2,870,652,936
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		3,331,965,984	2,870,730,559
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		10,127,458	(2,230,631)
50	Equity in Earnings for Year (Credit) (Account 418.1)		983,306	12,358,089
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			

52.1	Rounding			
53	Balance-End of Year (Total lines 49 thru 52)		11,110,764	10,127,458

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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 Instructions 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)	903,512,230	792,840,564	
3	Noncash Charges (Credits) to Income:			
4	Depreciation and Depletion	1,174,447,864	990,645,501	
5	Amortization of (Specify) (footnote details)			
5.1	Amortization of Nuclear Fuel	114,498,542	105,717,834	
5.2	Amortization of Premium, Discount and Debt Expense	7,730,342	7,229,126	
5.3	Amortization of Software and Other	104,130,912	114,123,083	
8	Deferred Income Taxes (Net)	162,988,984	142,685,569	
9	Investment Tax Credit Adjustment (Net)	(1,312,836)	(1,330,117)	
10	Net (Increase) Decrease in Receivables	15,030,481	(62,334,929)	
11	Net (Increase) Decrease in Inventory	(72,500,861)	(23,761,231)	
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory			
13	Net Increase (Decrease) in Payables and Accrued Expenses	(11,385,439)	58,358,319	
14	Net (Increase) Decrease in Other Regulatory Assets	(150,453,561)	(182,498,249)	
15	Net Increase (Decrease) in Other Regulatory Liabilities	(14,805,970)	317,162,228	
16	(Less) Allowance for Other Funds Used During Construction	70,205,064	53,396,561	
17	(Less) Undistributed Earnings from Subsidiary Companies	983,199	12,358,015	
18	Other (provide details in footnote):			
18.1	Other: Decrease (Increase) in Accrued Utility Revenues	(43,233,576)	17,799,722	
18.2	Other: Net Realized and Unrealized Hedging and Derivative Transactions	6,544,601	15,853,194	
18.3	Other: Changes in Other Current Assets and Liabilities	14,022,913	(34,877,024)	
18.4	Other: Changes in Noncurrent Liabilities and Deferred Amounts	(52,845,378)	(269,335,180)	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	2,085,180,985	1,922,523,834	
24	Cash Flows from Investment Activities:			
25	Construction and Acquisition of Plant (including land):			
26	Gross Additions to Utility Plant (less nuclear fuel)	(2,914,535,117)	(2,537,280,652)	
27	Gross Additions to Nuclear Fuel	(187,437,349)	(154,281,720)	
28	Gross Additions to Common Utility Plant	(243,871,913)	(172,770,036)	
29	Gross Additions to Nonutility Plant	(5,497,255)	(7,947,854)	
30	(Less) Allowance for Other Funds Used During Construction	(70,205,064)	(53,396,561)	

31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(3,281,136,570)	(2,818,883,701)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
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	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Investments in Utility Money Pool Arrangement	(812,000,000)	(390,000,000)
53.2	Repayments from Utility Money Pool Arrangement	845,000,000	414,000,000
53.3	Other: Miscellaneous Other Investing Activities	4,951,679	(2,955,515)
53.4	Other: Purchase of Investments in External Decommissioning Fund	(1,200,159,408)	(997,887,846)
53.5	Other: Proceeds from Sale of Investments in External Decomissioning Fund	1,197,389,856	961,228,946
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(3,245,954,443)	(2,834,498,116)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,082,330,339	687,072,867
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other: Capital Contributions (to) from Parent	656,892,793	714,772,952
64.2	Other: Borrowings under Utility Money Pool Arrangement	1,402,000,000	271,000,000
66	Net Increase in Short-Term Debt (c)	25,000,000	30,000,000
67	Other (provide details in footnote):		
70	Cash Provided by Outside Sources (Total 61 thru 69)	3,166,223,132	1,702,845,819
72	Payments for Retirement of:		
73	Long-term Debt (b)	(250,291,493)	(344,732)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		

76.1	Other: Repayments under Utility Money Pool Arrangement	(1,328,000,000)	(271,000,000)
76.2	Other: Miscellaneous Other Financing Activities		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(418,098,125)	(494,281,150)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	1,169,833,514	937,219,937
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	9,060,056	25,245,655
88	Cash and Cash Equivalents at Beginning of Period	59,252,039	34,006,384
90	Cash and Cash Equivalents at End of Period	68,312,095	59,252,039

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: CashAndCashEquivalents			
Cash (131)			\$ 4,437,525
Special Deposits (132-134)			3,281,822
Working Fund (135)			159,347
Temporary Cash Investments (136)			51,373,345
Cash and Cash Equivalents at End of Period			\$ 59,252,039
(b) Concept: CashAndCashEquivalents			
Cash (131)			\$ 5,809,859
Special Deposits (132-134)			3,774,380
Working Fund (135)			118,705
Temporary Cash Investments (136)			58,609,151
Cash and Cash Equivalents at End of Period			\$ 68,312,095
(c) Concept: CashAndCashEquivalents			
Cash (131)			\$ 4,437,525
Special Deposits (132-134)			3,281,822
Working Fund (135)			159,347
Temporary Cash Investments (136)			51,373,345
Cash and Cash Equivalents at End of Period			\$ 59,252,039

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

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

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

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, where 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.

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 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.

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 on the utility plant 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 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 operating expense 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 is 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, this brings 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 operating 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	\$	(566)
Current assets		329
Current liabilities		457
Other long-term assets		(3,698)
Long-term debt and other long-term liabilities		(4,393)
Statement of Income:		
Operating revenue	\$	96
Operating expenses		268
Other income and deductions		
Net Interest charges		20

Subsequent Events - Management has evaluated the impact of events occurring after Dec. 31, 2025 up to Feb. 25, 2026, the date NSP-Minnesota's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of the draft. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

FERC Order 898 — FERC Order 898 was implemented as of Jan. 1, 2025. See pages 204-207 for transfer detail.

Use of Estimates — NSP-Minnesota uses estimates based on the best information available to record transactions and balances resulting from business operations. Estimates are used for items such as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), 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 actual amounts can be determined. 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.
- 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 and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other available information. Regulatory assets and liabilities are reversed or 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. Such changes could have a material effect on NSP-Minnesota's results of operations, financial condition and cash flows.

See Note 4 for further information.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities utilizing 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.

Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes. 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, refundable to utility customers over the remaining life of the related assets. NSP-Minnesota anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

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 over the book depreciable lives of related property, as determined by tax regulations and NSP-Minnesota tax elections. For tax credits eligible to be recognized when earned, NSP-Minnesota considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

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. This evaluation includes consideration of whether tax credits are expected to be sold at a discount and impact the realization of amounts presented as deferred tax assets. Transferable tax credits are accounted for under ASC 740 *Income Taxes*, and valuation allowances and any adjustments for discounts incurred on sales transactions are recorded to deferred tax expense, typically recovered in regulatory mechanisms.

NSP-Minnesota measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

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.

Utility Plant and Depreciation in Regulated Operations — Utility plant 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 and replacement of items determined to be less than a unit of property are charged to expense as incurred.

Utility plant 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 utility plant 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.

Depreciation expense is recorded using the straight-line method over the plant's commission approved 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. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Accumulated removal costs are reflected in the balance sheet as a regulatory liability. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.9% for 2025 and 2024.

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

AROs — NSP-Minnesota records AROs as a liability in the period incurred (if fair value can be reasonably estimated), with the offsetting/associated 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 typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 9 for further information.

Nuclear Decommissioning — Nuclear decommissioning studies that estimate NSP-Minnesota’s costs of decommissioning its nuclear power plants are normally performed at least every three years and submitted to the state commissions for approval. The latest decommissioning study was completed in 2024.

NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility’s expected service life, typically based on the triennial decommissioning studies. 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 future decommissioning expenditures for NSP-Minnesota’s nuclear facilities are included in nuclear decommissioning fund and other assets on the balance sheets.

See Notes 7 and 9 for further information.

Leases — NSP-Minnesota evaluates contracts that may contain leases, including PPAs and arrangements for the use of office space and other facilities, as well as certain contracts for the use of land, vehicles and other equipment. A contract contains a lease if it conveys the exclusive right to control the use of a specific asset. A contract determined to contain a lease is evaluated further to determine whether the arrangement is an operating lease or a finance lease, including an assessment of whether the contract requires payments for substantially all of the value of the leased asset or whether the term of the contract is for substantially all of the expected remaining economic life of the leased asset, among other criteria for finance lease classification.

See Note 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 amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for 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 is performed. 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.

Estimated future expenditures to restore sites are generally treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses. Removal costs recovered in rates before the related costs are incurred are classified as a regulatory liability. When separate mechanisms are expected to provide cost recovery or when changes in projected costs occur near the end of a facility’s useful life, regulatory accounting may be applied.

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 systematically 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.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees.

NSP-Minnesota recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. Revenues and charges for short-term physical wholesale sales of excess energy transacted through regional transmission organization (RTOs) are also recorded on a gross basis. Other revenues and charges settled/facilitated through an RTO are 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 three 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 the lower of average cost or net realizable value.

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, rabbi trust assets, commodity derivatives, pension and postretirement plan assets and nuclear decommissioning fund assets at estimated fair values in its financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate 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, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

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

See Notes 7 and 8 for further information.

Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates and utility commodity prices, including forward contracts, futures, swaps and options. Derivatives that have not been designated or do not qualify 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.

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

Commodity Trading Operations — All applicable gains and losses related to commodity trading activities are shown on a net basis in electric operating revenues in the statement of income.

Commodity trading activities are not associated with energy produced from NSP-Minnesota’s generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 7 for further information.

Other Utility Items

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity and 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.

Alternative Revenue — Certain rate rider mechanisms (including decoupling/sales true up and conservation improvement program (CIP)/demand-side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items.

Billing amounts are revised periodically for differences between 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.

Conservation Programs — Costs incurred for DSM and 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 the year they are earned. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

Emissions Allowances — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

Environmental Credits — Cost of Environmental Credits that are utilized for compliance is recorded as electric fuel and purchased power expense. An inventory accounting model is used to account for Environmental Credits.

Sales of Environmental Credits are recorded in electric revenues on a gross basis. The cost of these Environmental Credits and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

Cost of Environmental Credits that are utilized to support commodity trading activities are recorded in a similar manner as the associated commodities and are presented on a net basis in electric operating revenues in the statement of income.

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
Crowned Ridge Interconnection, LLC	United States	50
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)	2025	2024
Current assets	\$ 17	\$ 15
Other assets	1	1
Total assets	<u>\$ 18</u>	<u>\$ 16</u>
Current liabilities	\$ 1	\$ —
Equity	17	16
Total liabilities and equity	<u>\$ 18</u>	<u>\$ 16</u>
(Millions of Dollars)	2025	2024
Operating income	\$ 1	\$ 17
Income taxes	—	(5)
Net income	<u>\$ 1</u>	<u>\$ 12</u>

3. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2025:

(Millions of Dollars, Except Percent Owned)	Plant in Service	Accumulated Depreciation	Percent Owned
Electric generation:			
Sherco Unit 3	\$ 638	\$ 515	59 %
Sherco common facilities	189	134	80
Sherco substation	5	4	59
Electric transmission:			
Grand Meadow	11	4	50
Huntley Wilmarth	49	4	50
CapX2020	867	169	51
Total (a)	<u>\$ 1,779</u>	<u>\$ 830</u>	

(a) Projects additionally include \$26 million in CWIP.

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

4. 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, 2025	Dec. 31, 2024 ^(a)
Other Regulatory Assets		
Asset retirement recovery	\$ 3,084	\$ 2,926
Pension and retiree medical obligations	321	336
Theoretical depreciation reserve surplus	202	211
Recoverable deferred taxes on AFUDC recorded in plant	150	137
Excess deferred taxes - TCJA	97	97
Nuclear refueling outage costs	78	71
Sales true-up and MN MISO capacity revenue	76	190
Renewable resources and environmental initiatives	40	37
Contract valuation adjustments ^(b)	19	23
PPA termination	13	18
Purchased power contracts costs	—	17
Other	75	65
Total other regulatory assets	<u>\$ 4,155</u>	<u>\$ 4,128</u>

(a) Prior period amounts have been classified to conform with current year presentation.

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

Components of regulatory liabilities:

(Millions of Dollars)	Dec. 31, 2025	Dec. 31, 2024 ^(a)
Other Regulatory Liabilities		
Plant removal costs	\$ 2,203	\$ 2,104
Deferred income tax adjustments and TCJA refunds ^(b)	1,051	1,109
Nuclear Decommissioning Trust investments	1,234	984
Deferred natural gas and electric energy/fuel costs ^(c)	214	360
Conservation programs	8	41
Contract valuation adjustments ^(d)	65	21
Other	173	187
Total other regulatory liabilities	<u>\$ 4,948</u>	<u>\$ 4,806</u>

(a) Prior period amounts have been classified to conform with current year presentation.

(b) Includes the revaluation of recoverable/regulated plant accumulated deferred income taxes and revaluation impact of non-plant accumulated deferred income taxes due to the TCJA.

(c) Includes Nuclear PTCs.

(d) Includes the fair value of FTR instruments utilized/intended to offset the impacts of transmission system congestion.

NSP-Minnesota's regulatory assets not earning a return include past expenditures of \$385 million and \$562 million at Dec. 31, 2025 and 2024, respectively, which predominately relate to certain prepaid pension amounts, sales true-up and revenue decoupling and other renewable resources/environmental initiatives. Additionally, the unfunded portion of pension and retiree medical obligations, net AROs and Renewable Development Fund Rider (i.e., deferrals for which cash has not been disbursed) do not earn a return.

5. Borrowings and Other Financing Instruments

Short-Term Borrowings

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

Money Pool — Xcel Energy Inc. and its utility subsidiaries (e.g., NSP-Minnesota, NSP-Wisconsin, Public Service Company of Colorado, and Southwest Public Service Company) (Xcel Energy) 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:

	Year Ended Dec. 31	
(Amounts in Millions, Except Interest Rates)	2025	2024
Borrowing limit	\$ 250	\$ 250
Amount outstanding at period end	74	—
Average amount outstanding	50	10
Maximum amount outstanding	250	139
Weighted average interest rate, computed on a daily basis	4.11 %	4.82 %
Weighted average interest rate at end of period	3.88	N/A

Commercial Paper — Commercial paper outstanding:

	Year Ended Dec. 31	
(Amounts in Millions, Except Interest Rates)	2025	2024
Borrowing limit	\$ 800	\$ 700
Amount outstanding at period end	220	195
Average amount outstanding	130	54
Maximum amount outstanding	610	400
Weighted average interest rate, computed on a daily basis	4.37 %	5.39 %
Weighted average interest rate at end of period	3.83	4.63

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, 2025 and 2024, there were \$44 million and \$12 million of letters of credit outstanding under the credit facility, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facility — In order to use commercial paper programs to fulfill short-term funding needs, NSP-Minnesota must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper exceeding available capacity under these credit facilities.

The lines of credit provide 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)	Amount Facility May Be Increased (Millions)	Additional Periods for Which a One-Year Extension May Be Requested ^(b)
2025 50.0 %	2024 47.0 % \$ 170	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 would 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, 2025, NSP-Minnesota was in compliance with all financial covenants on its debt agreements.

NSP-Minnesota had the following committed credit facility available as of Dec. 31, 2025 (in millions of dollars):

Credit Facility ^(a)	Drawn ^(b)	Available
\$ 800	\$ 264	\$ 536

^(a) This credit facility matures in December 2029.
^(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, 2025 and 2024.

Bilateral Credit Agreement — In April 2025, NSP-Minnesota’s uncommitted bilateral credit agreement was renewed for an additional one-year term. The credit agreement is limited in use to support letters of credit.

As of Dec. 31, 2025, and 2024 NSP-Minnesota had \$69 million and \$74 million outstanding letters of credit under the \$75 million Bilateral Credit Agreement, respectively.

Long-Term Borrowings and Other Financing Instruments

Generally, the property of NSP-Minnesota is subject to the lien of its first mortgage indenture for the benefit of bondholders. 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 (in millions of dollars):

Financing Instrument	Interest Rate	Maturity Date	2025	2024
First mortgage bonds	7.125 %	July 1, 2025	\$ —	\$ 250
First mortgage bonds	6.50	March 1, 2028	150	150
First mortgage bonds	2.25	April 1, 2031	425	425
First mortgage bonds (a)	5.05	May 15, 2035	600	—
First mortgage bonds	5.25	July 15, 2035	250	250
First mortgage bonds	6.25	June 1, 2036	400	400
First mortgage bonds	6.20	July 1, 2037	350	350
First mortgage bonds	5.35	Nov. 1, 2039	300	300
First mortgage bonds	4.85	Aug. 15, 2040	250	250
First mortgage bonds	3.40	Aug. 15, 2042	500	500
First mortgage bonds (b)	4.125	May 15, 2044	300	300
First mortgage bonds (b)	4.00	Aug. 15, 2045	300	300
First mortgage bonds (b)	3.60	May 15, 2046	350	350
First mortgage bonds	3.60	Sept. 15, 2047	600	600
First mortgage bonds (b)	2.90	March 1, 2050	600	600
First mortgage bonds (b)	2.60	June 1, 2051	700	700
First mortgage bonds (b)	3.20	April 1, 2052	425	425
First mortgage bonds	4.50	June 1, 2052	500	500
First mortgage bonds	5.10	May 15, 2053	800	800
First mortgage bonds (c)	5.40	March 15, 2054	700	700
First mortgage bonds (b)	5.65	May 15, 2055	500	—
Other long-term debt			1	2
Unamortized discount			(50)	(49)
Total long-term debt			<u>\$ 8,952</u>	<u>\$ 8,103</u>

^(a) 2025 financing.
^(b) During 2025 and 2024, Xcel Energy Inc. purchased a portion of these NSP-Minnesota first mortgage bonds for \$607 million and \$166 million, respectively. Interest expense related to these repurchased bonds was \$6 million and immaterial for the years ended Dec. 31, 2025 and 2024, respectively.
^(c) 2024 financing.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2026	\$ —
2027	—
2028	150
2029	—
2030	—

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 commissions additionally impose dividend limitations, which are more restrictive than those imposed by the FERC.

Requirements and actuals as of Dec. 31, 2025:

Equity to Total Capitalization Ratio Required Range	Equity to Total Capitalization Ratio Actual
Low	2025
47.25 %	53.16 %
High	
57.75 %	
Unrestricted Retained Earnings	Limit on Total Capitalization
\$ 2,185 million	\$ 19,547 million
	\$ 22,607 million

6. Income Taxes

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 reconciliation for years ended Dec. 31:

	2025	2024
Income before income taxes (domestic)	\$ 710	\$ 432
Federal statutory rate impact	149	91
(Decreases) increases in tax from:		
Tax credits		
Production Tax Credits ^(a)	(346)	(434)
Other	(6)	(7)
Regulatory adjustments ^(b)		
Plant related excess deferred taxes	(33)	(33)
AFUDC equity	(15)	(11)
Other	11	9
State income taxes, net of federal tax effect ^(c)	48	27
Other	(2)	(3)
Income tax benefit	<u>(194)</u>	<u>(361)</u>
	<u>2025</u>	<u>2024</u>
Federal statutory rate	21.0 %	21.0 %
(Decreases) increases in tax from:		
Tax credits		
Production Tax Credits ^(a)	(48.7)	(100.5)
Other	(0.9)	(1.6)
Regulatory adjustments ^(b)		
Plant related excess deferred taxes	(4.6)	(7.7)
AFUDC equity	(2.1)	(2.6)
Other	1.5	2.1
State income taxes, net of federal tax effect ^(c)	6.7	6.3
Other	(0.3)	(0.6)
Effective income tax rate	<u>(27.4)%</u>	<u>(83.6)%</u>

^(a) Wind, Solar and Nuclear Production Tax Credits (net of estimated transfer discounts) are generally credited to customers (reduction to revenue) and do not materially impact earnings.
^(b) Regulatory adjustments primarily relate to the credit of plant related excess deferred taxes to customers as well as the capitalization of AFUDC equity for book purposes only (permanent difference). Income tax benefits associated with the credit of excess deferred taxes are offset by corresponding revenue reductions.

(c) State and local income taxes are primarily made up of the following jurisdictions: Minnesota.

Components of income tax expense (benefit) for years ended Dec. 31:

(Millions of Dollars)	2025	2024
Current federal tax expense (benefit)	\$ 38	\$ (153)
Current state tax benefit	—	(27)
Current change in unrecognized tax benefit	(1)	2
Deferred federal tax benefit	(290)	(243)
Deferred state tax expense	61	61
Deferred investment tax credits	(1)	(1)
Other	(1)	—
Total income tax benefit	<u>\$ (194)</u>	<u>\$ (361)</u>

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

(Millions of Dollars)	2025	2024
Deferred tax expense (benefit) excluding items below	\$ 319	\$ 247
Adjustments to deferred income taxes for tax credit cash transfers	(393)	(325)
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(155)	(99)
Tax expense allocated to other comprehensive income and other	—	(5)
Deferred tax benefit	<u>\$ (229)</u>	<u>\$ (182)</u>

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

(Millions of Dollars)	2025	2024 ^(a)
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 3,927	\$ 3,579
Regulatory assets	(152)	(125)
Operating lease assets	35	115
Pension expense	73	67
Deferred fuel costs	13	21
Other	13	23
Total deferred tax liabilities	<u>\$ 3,909</u>	<u>\$ 3,680</u>
Deferred tax assets:		
Tax credit carryforward	\$ 877	\$ 892
Differences between book and tax bases of property	428	405
Regulatory liabilities	(29)	(1)
Operating lease liabilities	35	115
Rate refund	10	10
NOL and tax credit valuation allowances	(69)	(68)
Other employee benefits	29	28
Deferred investment tax credits	3	4
Other	84	73
Total deferred tax assets	<u>\$ 1,368</u>	<u>\$ 1,458</u>
Net deferred tax liability	<u>\$ 2,541</u>	<u>\$ 2,222</u>

(a) Prior periods have been reclassified to conform to current year position.

Cash received (paid) for income taxes for the years ended Dec. 31:

(Millions of Dollars)	2025	2024
Cash received for income taxes: federal, net ^(b)	\$ 364	\$ 476
Cash received (paid) for income taxes: state		
Minnesota	5	(29)
Other	1	(1)
Total	<u>\$ 370</u>	<u>\$ 446</u>

(a) Includes proceeds from tax credit transfers.

Other Income Tax Matters — Tax credits represent the deferred tax asset. Tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2025	2024
Federal tax credit carryforwards	816	831
Valuation allowances for federal credit carryforwards	(9)	(11)
State tax credit carryforwards, net of federal detriment	60	61
Valuation allowances for state credit carryforwards, net of federal benefit	(60)	(57)

Federal carryforward periods expire between 2038 and 2045. State carryforward periods, not including those with indefinite carryforward periods, expire between 2026 and 2036.

Unrecognized Tax Benefits

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	Expiration
2022	September 2026

Additionally, the statute of limitations related to federal tax credit carryforwards will remain open until those credits are utilized in subsequent returns.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state tax returns based on income in its major operating jurisdictions and various other state income-based returns. As of Dec. 31, 2025, NSP-Minnesota's earliest open tax years (subject to examination by state taxing authorities in its major operating jurisdictions) were as follows:

State	Tax Year(s)	Expiration
Minnesota	2021	June 2026

In 2025, Minnesota began an audit of tax years 2021-2023. As of Dec. 31, 2025 no material adjustments have been proposed.

Unrecognized tax benefit balance may include permanent tax positions, which if recognized would affect the effective tax rate (ETR). In addition, the unrecognized tax benefit balance may include temporary tax positions for which deductibility is highly certain, but for which there is uncertainty about the timing. A change in the period of deductibility would not affect the ETR but would accelerate the payment to the taxing authority.

Unrecognized tax benefits - permanent vs temporary:

(Millions of Dollars)	Dec. 31, 2025	Dec. 31, 2024
Unrecognized tax benefit — Permanent tax positions	\$ 19	\$ 20
Unrecognized tax benefit — Temporary tax positions	—	—
Total unrecognized tax benefit	<u>\$ 19</u>	<u>\$ 20</u>

Changes in unrecognized tax benefits:

(Millions of Dollars)	2025	2024
Balance at Jan. 1	\$ 20	\$ 18
Additions based on tax positions related to the current year	2	3
Reductions for tax positions of prior years	(3)	(1)
Balance at Dec. 31	<u>\$ 19</u>	<u>\$ 20</u>

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

(Millions of Dollars)	Dec. 31, 2025	Dec. 31, 2024
NOL and tax credit carryforwards	\$ (16)	\$ (17)

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)	2025		2024	
Receivable for interest related to unrecognized tax benefits at Jan. 1	\$	—	\$	1
Interest expense related to unrecognized tax benefits	\$	—	\$	(1)
Receivable for interest related to unrecognized tax benefits at Dec. 31	\$	—	\$	—

No penalties were accrued related to unrecognized tax benefits as of Dec. 31, 2025 or 2024.

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 accumulated deferred income tax (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, 2025 and 2024 is reflected below.

(Millions of Dollars)	Dec. 31, 2025		Dec. 31, 2024	
	Account 182.3	Account 254	Account 182.3	Account 254
Protected				
Plant	\$ —	\$ 937	\$ —	\$ 981
Nonplant	81	—	87	—
Unprotected				
Plant	—	105	—	114
Nonplant	6	10	9	14
Total				
Plant	\$ —	\$ 1,042	\$ —	\$ 1,095
Nonplant	\$ 87	\$ 10	\$ 96	\$ 14

Excess and deficient ADITs in 2025 were amortized in the Statement of Income as follows:

(Millions of Dollars)	Dec. 31, 2025	
Protected		
Plant	\$ —	(28)
Nonplant		4
Unprotected		
Plant		(6)
Nonplant		(1)
Total		
Plant	\$ —	(34)
Nonplant	\$ —	3

7. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

Accounting guidance for fair value measurements and disclosures provides a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

- 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 actively traded instruments with observable actual trading prices.
- Level 2 — Pricing inputs are other than actual trading 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 include those valued with models requiring significant judgment or estimation.

Specific valuation methods include:

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 (net asset values). The investments in commingled funds may be redeemed for NAV with proper notice. Private equity commingled funds 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 may be redeemed with proper notice, however, withdrawals 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 — Fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — 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 contracts relate to inactive delivery locations or extend to periods beyond those readily observable on active exchanges, the significance of the use of less observable inputs 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 FTRs (financial transmission rights). FTRs purchased from an 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 values of these instruments are derived from, and designed to offset, the costs 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 these instruments. FTRs are recognized at fair value and adjusted each period prior to settlement. Given the limited observability of certain variables underlying the reported auction values of FTRs, these fair value measurements have been assigned a Level 3 classification.

Net congestion costs, including the impact of FTR settlements are shared through fuel and purchased energy cost recovery mechanisms. As such, the fair value of the unsettled instruments (i.e., derivative asset or liability) is offset/deferred as a regulatory asset or liability.

Non-Derivative Fair Value Measurements

The Nuclear Regulatory Commission 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 investment targets by asset class for the 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 \$1.8 billion and \$1.4 billion as of Dec. 31, 2025 and 2024, respectively, and unrealized losses were \$47 million and \$49 million as of Dec. 31, 2025 and 2024, respectively.

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

(Millions of Dollars)	Dec. 31, 2025					
	Cost	Fair Value			NAV	Total
		Level 1	Level 2	Level 3		
Nuclear decommissioning fund						
Cash equivalents	\$ 60	\$ 60	\$ —	\$ —	\$ —	\$ 60
Commingled funds	720	—	—	—	1,072	1,072
Debt securities	944	—	934	11	—	945
Equity securities	505	1,861	2	—	—	1,863
Total	<u>\$ 2,229</u>	<u>\$ 1,921</u>	<u>\$ 936</u>	<u>\$ 11</u>	<u>\$ 1,072</u>	<u>\$ 3,940</u>

(Millions of Dollars)	Dec. 31, 2024					
	Cost	Fair Value			NAV	Total
		Level 1	Level 2	Level 3		
Nuclear decommissioning fund						
Cash equivalents	\$ 39	\$ 39	\$ —	\$ —	\$ —	\$ 39
Commingled funds	703	—	—	—	1,025	1,025
Debt securities	866	—	832	14	—	846
Equity securities	522	1,583	1	—	—	1,584
Total	<u>\$ 2,130</u>	<u>\$ 1,622</u>	<u>\$ 833</u>	<u>\$ 14</u>	<u>\$ 1,025</u>	<u>\$ 3,494</u>

For the years ended Dec. 31, 2025 and 2024, there were immaterial Level 3 nuclear decommissioning fund investments or transfer of amounts between levels.

Contractual maturity dates of debt securities in the nuclear decommissioning fund as of Dec. 31, 2025:

(Millions of Dollars)	Final Contractual Maturity				
	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	\$ 344	\$ 292	\$ 299	\$ 945

Derivative Activities and 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 and utility commodity prices.

Interest Rate Derivatives — NSP-Minnesota enters into contracts that effectively fix the interest rate on a specified principal amount of a hypothetical future debt issuance. These financial swaps net settle based on changes in a specified benchmark interest rate, acting as a hedge of changes in market interest rates that will impact specified anticipated debt issuances. These derivative instruments are designated as cash flow hedges for accounting purposes, with changes in fair value prior to occurrence of the hedged transactions recorded as other comprehensive income.

As of Dec. 31, 2025, accumulated other comprehensive loss related to interest rate derivatives included immaterial net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings. As of Dec. 31, 2025, NSP-Minnesota had unsettled interest rate derivatives with a notional amount of \$210 million.

See Note 10 for the financial impact of qualifying interest rate 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.

Wholesale and Commodity Trading — 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 the activities governed by this policy.

Results of derivative instrument transactions entered into for trading purposes are presented in the statements of income as electric revenues, net of any sharing with customers. These activities are not intended to mitigate commodity price risk associated with regulated electric and natural gas operations. Sharing of these margins is determined through state regulatory proceedings as well as the operation of the FERC-approved joint operating agreement.

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. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale and Financial transmission rights (FTR).

The most significant derivative positions outstanding at Dec. 31, 2025 and 2024 for this purpose relate to FTR instruments administered by MISO. These instruments are intended to offset the impacts of transmission system congestion.

When NSP-Minnesota enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers, the instruments are not typically designated as qualifying hedging transactions. The classification of unrealized losses or gains on these instruments as a regulatory asset or liability, if applicable, is based on approved regulatory recovery mechanisms.

As of Dec. 31, 2025, NSP-Minnesota had no commodity contracts designated as cash flow hedges.

Gross notional amounts of commodity forwards, options and FTRs:

(Amounts in Millions) ^{(a)(b)}	Dec. 31, 2025	Dec. 31, 2024
Megawatt hours of electricity	27	31
Million British thermal units of natural gas	30	57

- ^(a) Not reflective of net positions in the underlying commodities.
^(b) Notional amounts for options 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 on the balance sheets. NSP-Minnesota often has significant concentrations of credit risk with particular entities or industries in its wholesale, trading and non-trading commodity activities.

As of Dec. 31, 2025, three of NSP-Minnesota’s five most significant counterparties for these activities, comprising \$22 million or 30% of this credit exposure, had investment grade credit ratings from S&P Global Ratings, Moody’s Investor Services or Fitch Ratings.

One of the five most significant counterparties, comprising \$25 million or 33% of this credit exposure, were not rated by these external ratings agencies, but based on NSP-Minnesota’s internal analysis, had credit quality consistent with investment grade.

One of these significant counterparties, comprising \$25 million or 33% of this credit exposure, had credit quality less than investment grade, based on internal analysis.

Four of these significant counterparties are municipal or cooperative electric entities, RTOs or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that NSP-Minnesota enters into, including those accounted for as normal purchase and 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 the applicable utility subsidiary’s credit ratings are downgraded below its investment grade credit rating by any of the major credit rating agencies.

As of Dec. 31, 2025 and 2024, there were \$7 million and \$11 million, respectively, of derivative liabilities with such underlying contract provisions, respectively.

Certain contracts also contain cross default provisions that may require the posting of collateral or settlement of the contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

As of Dec. 31, 2025 and 2024, there were approximately \$54 million and \$63 million of derivative liabilities with such underlying contract provisions, respectively.

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 a given utility subsidiary’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, 2025 and 2024.

Recurring Derivative Fair Value Measurements —

Impact of derivative activity:

(Millions of Dollars)	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:	
	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities
Year Ended Dec. 31, 2025		
Derivatives designated as cash flow hedges		
Interest rate	\$ 5	\$ —
Total	\$ 5	\$ —
Other derivative instruments		
Electric commodity	\$ —	\$ 54
Natural gas commodity	—	(2)
Total	\$ —	\$ 52
Year Ended Dec. 31, 2024		
Derivatives designated as cash flow hedges		
Interest rate	\$ 16	\$ —
Total	\$ 16	\$ —
Other derivative instruments		
Electric commodity	\$ —	\$ (18)
Natural gas commodity	—	2
Total	\$ —	\$ (16)

(Millions of Dollars)	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Year Ended Dec. 31, 2025			
Other derivative instruments			
Commodity trading	\$ —	\$ —	\$ (5) ^(a)
Electric commodity	—	(9) ^(b)	—
Natural gas commodity	—	—	(8) ^{(c)(d)}
Total	\$ —	\$ (9)	\$ (13)
Year Ended Dec. 31, 2024			
Derivatives designated as cash flow hedges			
Interest rate	\$ 1 ^(e)	\$ —	\$ —
Total	\$ 1	\$ —	\$ —
Other derivative instruments			
Commodity trading	\$ —	\$ —	\$ (10) ^(b)
Electric commodity	—	21 ^(c)	—
Natural gas commodity	—	—	(7) ^{(d)(e)}
Total	\$ —	\$ 21	\$ (17)

- ^(a) Recorded to electric revenues. Presented amounts do not reflect non-derivative transactions or margin sharing with customers.
^(b) 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. FTR settlements are shared with customers and do not have a material impact on net income. Presented amounts reflect changes in fair value between auction and settlement dates, but exclude the original auction fair value.
^(c) Recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset, as appropriate.
^(d) Relates primarily to option premium amortization.
^(e) Recorded to interest charges.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2025 and 2024.

Derivative assets and liabilities measured at fair value on a recurring basis were as follows:

(Millions of Dollars)	Dec. 31, 2025						Dec. 31, 2024					
	Fair Value			Fair Value Total	Netting ^(a)	Total	Fair Value			Fair Value Total	Netting ^(a)	Total
	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative assets												
Derivatives designated as cash flow hedges:												
Interest rate	\$ —	\$ 1	\$ —	\$ 1	\$ —	\$ 1	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Other derivative instruments:												
Commodity trading	\$ 2	\$ 7	\$ 7	\$ 16	\$ (10)	\$ 6	\$ 5	\$ 20	\$ 8	\$ 33	\$ (22)	\$ 11
Electric commodity	—	—	68	68	(3)	65	—	—	23	23	(2)	21
Natural gas commodity	—	6	—	6	—	6	—	4	—	4	—	4
Total current derivative assets	<u>\$ 2</u>	<u>\$ 14</u>	<u>\$ 75</u>	<u>\$ 91</u>	<u>\$ (13)</u>	<u>\$ 78</u>	<u>\$ 5</u>	<u>\$ 24</u>	<u>\$ 31</u>	<u>\$ 60</u>	<u>\$ (24)</u>	<u>\$ 36</u>
Noncurrent derivative assets												
Other derivative instruments:												
Commodity trading	\$ 3	\$ 27	\$ 35	\$ 65	\$ (11)	\$ 54	\$ 3	\$ 33	\$ 47	\$ 83	\$ (16)	\$ 67
Total noncurrent derivative assets	<u>\$ 3</u>	<u>\$ 27</u>	<u>\$ 35</u>	<u>\$ 65</u>	<u>\$ (11)</u>	<u>\$ 54</u>	<u>\$ 3</u>	<u>\$ 33</u>	<u>\$ 47</u>	<u>\$ 83</u>	<u>\$ (16)</u>	<u>\$ 67</u>

(Millions of Dollars)	Dec. 31, 2025						Dec. 31, 2024					
	Fair Value			Fair Value Total	Netting ^(a)	Total	Fair Value			Fair Value Total	Netting ^(a)	Total
	Level 1	Level 2	Level 3				Level 1	Level 2	Level 3			
Current derivative liabilities												
Other derivative instruments:												
Commodity trading	\$ 5	\$ 15	\$ 6	\$ 26	\$ (12)	\$ 14	\$ 6	\$ 35	\$ 5	\$ 46	\$ (22)	\$ 24
Electric commodity	—	—	3	3	(3)	—	—	—	1	1	(1)	—
Natural gas commodity	—	3	—	3	—	3	—	1	—	1	—	1
Total current derivative liabilities	<u>\$ 5</u>	<u>\$ 18</u>	<u>\$ 9</u>	<u>\$ 32</u>	<u>\$ (15)</u>	<u>17</u>	<u>\$ 6</u>	<u>\$ 36</u>	<u>\$ 6</u>	<u>\$ 48</u>	<u>\$ (23)</u>	<u>25</u>
PPAs ^(b)						6						6
Current derivative instruments						<u>\$ 23</u>						<u>\$ 31</u>
Noncurrent derivative liabilities												
Other derivative instruments:												
Commodity trading	\$ 6	\$ 24	\$ 40	\$ 70	\$ (13)	\$ 57	\$ 9	\$ 30	\$ 40	\$ 79	\$ (18)	\$ 61
Total noncurrent derivative liabilities	<u>\$ 6</u>	<u>\$ 24</u>	<u>\$ 40</u>	<u>\$ 70</u>	<u>\$ (13)</u>	<u>57</u>	<u>\$ 9</u>	<u>\$ 30</u>	<u>\$ 40</u>	<u>\$ 79</u>	<u>\$ (18)</u>	<u>61</u>
PPAs ^(b)						10						16
Noncurrent derivative instruments						<u>\$ 67</u>						<u>\$ 77</u>

^(a) NSP-Minnesota nets derivative instruments and related collateral on its balance sheets when supported by a legally enforceable master netting agreement. At Dec. 31, 2025 and 2024, derivative assets and liabilities include no obligations to return cash collateral. At Dec. 31, 2025 and 2024, derivative assets and liabilities include rights to reclaim cash collateral of \$4 million and \$1 million, respectively. Counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

^(b) NSP-Minnesota currently applies the normal purchase exception to qualifying PPAs. Balance relates to specific contracts that were previously recognized at fair value prior to applying the normal purchase exception, and are being amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Changes in Level 3 commodity derivatives:

(Millions of Dollars)	Year Ended Dec. 31	
	2025	2024
Balance at Jan. 1	\$ 32	\$ 51
Purchases ^(a)	62	72
Settlements ^(a)	(120)	(61)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings ^(b)	(13)	(9)
Net gain (losses) recognized as regulatory assets and liabilities ^(a)	100	(21)
Balance at Dec. 31	<u>\$ 61</u>	<u>\$ 51</u>

^(a) Relates primarily to FTR instruments administered by MISO.

^(b) Relates to commodity trading and is subject to substantial offsetting losses and gains on derivative instruments categorized as levels 1 and 2 in the income statement. See above tables for the income statement impact of derivative activity, including commodity trading gains and losses.

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)	2025		2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt - Advances from associated companies	953	699	166	99
Total Long-term debt	\$ 8,952	\$ 7,154	\$ 8,103	\$ 6,755

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, 2025 and 2024, 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

Pension and Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has several noncontributory, qualified, defined benefit pension plans that cover almost all employees. All newly hired or rehired employees participate under the Cash Balance formula, which is based on pay credits using a percentage of annual eligible pay and annual interest credits.

The average annual interest crediting rates for these plans was 4.77% and 4.89% in 2025 and 2024, respectively.

Some employees may participate under legacy formulas such as the traditional final average pay or pension equity. 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.

Xcel Energy’s postretirement health care benefit plan is a continuation of certain welfare benefit programs for current employees. A full-time employee’s date of hire or a retiree’s date of retirement determine eligibility for each of the programs.

Xcel Energy’s investment-return assumption considers the expected long-term performance for each of the asset classes in its pension and postretirement health care portfolio. Xcel Energy considers the historical returns achieved by its asset portfolios over long time periods, as well as the long-term projected return levels from investment experts. 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 2025 were above the assumed level of 7.25%, and in 2024 they were below.
- In 2026, NSP-Minnesota’s expected investment-return assumption is 7.25%.

Pension plan and postretirement benefit assets are invested in a portfolio according to Xcel Energy’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.

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 consider many factors and generally 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

For each of the fair value hierarchy levels, NSP-Minnesota’s pension plan assets measured at fair value:

(Millions of Dollars)	Dec. 31, 2025 (a)					Dec. 31, 2024 (a)				
	Level 1	Level 2	Level 3	Measured at NAV	Total	Level 1	Level 2	Level 3	Measured at NAV	Total
Cash equivalents	\$ 23	\$ —	\$ —	\$ —	\$ 23	\$ 24	\$ —	\$ —	\$ —	\$ 24
Commingled funds	—	—	—	246	246	—	—	—	219	219
Debt securities	—	146	1	—	147	—	123	1	—	124
Equity securities	5	—	—	—	5	6	—	—	—	6
Partnerships ^(b)	—	—	—	165	165	—	—	—	154	154
Other	—	2	—	—	2	—	1	—	—	1
Total	<u>\$ 28</u>	<u>\$ 148</u>	<u>\$ 1</u>	<u>\$ 411</u>	<u>\$ 588</u>	<u>\$ 30</u>	<u>\$ 124</u>	<u>\$ 1</u>	<u>\$ 373</u>	<u>\$ 528</u>

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

^(b) Prior period amounts have been reclassified to conform with current year presentation.

NSP-Minnesota has immaterial postretirement benefit plan assets that were measured at fair value at Dec. 31, 2025 and 2024.Immaterial assets were transferred in or out of Level 3 for 2025 and 2024.

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:

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2025	2024	2025	2024
Change in Benefit Obligation:				
Obligation at Jan. 1	\$ 612	\$ 660	\$ 41	\$ 42
Service cost	22	22	—	1
Interest cost	34	34	2	2
Actuarial loss (gain)	25	(22)	3	1
Benefit payments	(61)	(82)	(5)	(5)
Obligation at Dec. 31	<u>\$ 632</u>	<u>\$ 612</u>	<u>\$ 41</u>	<u>\$ 41</u>
Change in Fair Value of Plan Assets:				
Fair value of plan assets at Jan. 1	\$ 528	\$ 562	\$ 2	\$ 3
Actual return on plan assets	67	7	—	—
Employer contributions	54	41	6	4
Benefit payments	(61)	(82)	(5)	(5)
Fair value of plan assets at Dec. 31	<u>\$ 588</u>	<u>\$ 528</u>	<u>\$ 3</u>	<u>\$ 2</u>
Funded status of plans at Dec. 31	<u>\$ (44)</u>	<u>\$ (84)</u>	<u>\$ (38)</u>	<u>\$ (39)</u>
Amounts recognized in the Balance Sheet at Dec. 31:				
Current liabilities	\$ —	\$ —	\$ (2)	\$ (3)
Noncurrent liabilities	(44)	(84)	(36)	(36)
Net amounts recognized	<u>\$ (44)</u>	<u>\$ (84)</u>	<u>\$ (38)</u>	<u>\$ (39)</u>

	Pension Benefits		Postretirement Benefits	
	2025	2024	2025	2024
Discount rate for year-end valuation	5.78 %	5.88 %	5.66 %	5.88 %
Expected average long-term increase in compensation level	4.25 %	4.25 %	N/A	N/A
Mortality table	PRI-2012	PRI-2012	PRI-2012	PRI-2012
Health care costs trend rate — initial: Pre-65	N/A	N/A	7.00 %	7.00 %
Health care costs trend rate — initial: Post-65	N/A	N/A	7.50 %	7.50 %
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	8	9

Accumulated benefit obligation for the pension plan was \$580 million and \$557 million as of Dec. 31, 2025 and 2024, respectively.

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

Components of net periodic benefit cost and amounts recognized in other comprehensive income and regulatory assets and liabilities:

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2025	2024	2025	2024
Service cost	\$ 22	\$ 22	\$ —	\$ 1
Interest cost	34	34	2	2
Expected return on plan assets	(45)	(46)	—	—
Amortization of prior service cost	—	—	—	—
Amortization of net loss	11	13	1	—
Settlement charge (a)	—	37	—	—
Net periodic pension cost	22	60	3	3
Effects of regulation	9	(30)	—	—
Net benefit cost recognized for financial reporting	<u>\$ 31</u>	<u>\$ 30</u>	<u>\$ 3</u>	<u>\$ 3</u>
Significant Assumptions Used to Measure Costs:				
Discount rate	5.88 %	5.49 %	5.88 %	5.54 %
Expected average long-term increase in compensation level	4.25	4.25	—	—
Expected average long-term rate of return on assets	7.25	7.25	6.25	5.00

(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 2024, as a result of lump-sum distributions during the plan year, NSP-Minnesota recorded a total pension settlement charge of \$37 million, which was not recognized in earnings due to the effects of regulation. There were no settlement charges recorded for the qualified pension plans in 2025.

(Millions of Dollars)	Pension Benefits		Postretirement Benefits	
	2025	2024	2025	2024
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:				
Net loss	\$ 281	\$ 289	\$ 17	\$ 14
Total	<u>\$ 281</u>	<u>\$ 289</u>	<u>\$ 17</u>	<u>\$ 14</u>
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost Have Been Recorded as Follows Based Upon Expected Recovery in Rates:				
Current regulatory assets	\$ 13	\$ 14	\$ 1	\$ —
Noncurrent regulatory assets	268	275	15	13
Net-of-tax accumulated other comprehensive income	—	—	1	1
Total	<u>\$ 281</u>	<u>\$ 289</u>	<u>\$ 17</u>	<u>\$ 14</u>
Measurement date	Dec 31, 2025		Dec 31, 2024	

Cash Flows — Funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the requirements of income tax and other pension-related regulations. Required contributions were made in 2024 - 2026 to meet minimum funding requirements.

Total voluntary and required pension funding contributions across all four of Xcel Energy's pension plans were as follows:

- \$75 million in January 2026, of which \$33 million is attributable to NSP-Minnesota.
- \$125 million in 2025, of which \$54 million was attributable to NSP-Minnesota.
- \$100 million in 2024, of which \$41 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. Xcel Energy's voluntary postretirement funding contributions were as follows:

- \$8 million expected in 2026, of which \$5 million is attributable to NSP-Minnesota.
- \$13 million during 2025, of which \$6 million, was attributable to NSP-Minnesota.
- \$11 million during 2024, of which \$4 million was attributable to NSP-Minnesota.

Targeted asset allocations:

	Pension Benefits		Postretirement Benefits	
	2025	2024	2025	2024
Long-duration fixed income and interest rate swap securities	38 %	38 %	— %	— %
Domestic and international equity securities	30	31	25	25
Alternative investments	19	20	13	11
Short-to-intermediate fixed income securities	11	9	61	61
Cash	2	2	1	3
Total	<u>100 %</u>	<u>100 %</u>	<u>100 %</u>	<u>100 %</u>

The asset allocations above reflect target allocations approved in the calendar year to take effect in the subsequent year.

Plan Amendments — There were no significant plan amendments made in 2025 and 2024 which affected the pension or postretirement benefit obligation.

Projected Benefit Payments

NSP-Minnesota's projected benefit payments:

(Millions of Dollars)		Projected Pension Benefit Payments		Net Projected Postretirement Health Care Benefit Payments (a)	
2026	\$	73	\$		5
2027		65			4
2028		62			4
2029		61			4
2030		59			4
2031-2035		276			15

(a) Amount is reported net of expected Medicare Part D subsidies, which are immaterial.

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 \$15 million in 2025 and \$14 million in 2024.

9. Commitments and Contingencies

Legal

NSP-Minnesota is involved in various litigation matters 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 a series of complex judgments about future events. Management maintains accruals for losses 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 but not limited to 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, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, would have a material effect on NSP-Minnesota’s financial statements. Legal fees are generally expensed as incurred.

Nuclear Antitrust Class Action — A class action complaint was filed in federal court for the District of Maryland in July 2025, alleging violations of the Sherman Antitrust Act in establishing wages for employees at nuclear facilities since 2003. The amended complaint names 46 defendants, including 45 entities that allegedly “own and/or operate all 54 commercial nuclear power plants in the United States,” including Xcel Energy Inc., Xcel Energy Services Inc., and NSP-Minnesota. NSP-Minnesota owns and operates two nuclear facilities in Minnesota, and disputes the allegations set forth against it and the other company entities. The litigation is ongoing, and Xcel Energy assesses the risk of a material impact to its financial statements as remote.

Rate Matters and Other

NSP-Minnesota is involved in various regulatory proceedings arising in the ordinary course of business. Until resolution, typically in the form of a rate order, uncertainties may exist regarding the ultimate rate treatment for certain activities and transactions. Amounts have been recognized for probable and reasonably estimable losses that may result. Unless otherwise disclosed, any reasonably possible range of loss in excess of any recognized amount is not expected to have a material effect on the financial statements.

Prairie Island Outage Prudency Review — In March 2024, NSP-Minnesota filed its annual fuel clause adjustment true-up petition to the MPUC. In a response to that petition, intervenors recommended refunds for replacement power costs related to an outage at the Prairie Island generating station (October 2023 through February 2024).

In a September 2024 decision, the MPUC ruled NSP-Minnesota was imprudent in the operation of the Prairie Island nuclear plant based on an incident that resulted in the extended outage. The MPUC did not quantify the refund and referred the determination of the refund amount to the Office of Administrative Hearings. NSP-Minnesota recorded an estimated liability for a customer refund in 2024.

In May 2025, in the resulting case currently before an ALJ to determine the refund amount, NSP-Minnesota submitted direct testimony asserting that no more than \$6 million of customer refunds are warranted for the outage.

Rebuttal and surrebuttal testimony were filed in August and September 2025 and final briefs were filed in January 2026. Intervenor briefs included recommendations for customer refunds of approximately \$40 million to account for the total impact of the outage on 2023 and 2024. An ALJ report is expected in March 2026, with a MPUC decision expected in the second quarter of 2026.

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 their predecessors or other parties have caused environmental contamination.

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

MGP, Landfill and Disposal Sites

NSP-Minnesota is investigating, remediating or performing post-closure actions at five historical MGP, landfill or other disposal sites across its service territories.

NSP-Minnesota has an immaterial amount of remaining liabilities for resolution of these issues, however, the final outcome and timing are unknown. In addition, there may be regulatory recovery, insurance recovery and/or recovery from other potentially responsible parties, offsetting a portion of costs incurred.

Environmental Requirements — Water and Waste

Coal Ash Regulation — NSP-Minnesota is subject to the coal combustion residuals (CCR) Rule, which imposes requirements for handling, storage, treatment and disposal of coal ash and other solid waste.

In May 2024, final amendments to the CCR Rule were published, widening its scope to include legacy CCR surface impoundments at inactive facilities and previously exempt areas where CCR was placed directly on land at CCR-regulated facilities, including areas of beneficial use.

As a requirement of the CCR Rule, utilities must complete facility evaluations and groundwater sampling around their subject landfills, surface impoundments and certain other areas where coal ash was placed on land.

If certain impacts to groundwater are detected, utilities are required to perform additional groundwater investigations and/or perform corrective actions, beginning with an Assessment of Corrective Measures.

NSP-Minnesota expects to incur \$5 million for investigations through 2028 to perform required reporting and assess whether corrective actions are necessary. AROs have been recorded for each of these activities, and amounts are expected to be recoverable through regulatory mechanisms.

NSP-Minnesota has also identified coal ash that is expected to be required to be removed from certain closed coal generating facilities at estimated costs totaling approximately \$60 million. AROs have been recorded, with the costs expected to be recoverable through regulatory mechanisms.

NSP-Minnesota continues to perform site investigation activities related to the CCR Rule, which may result in updates to estimated costs as well as identification of additional required corrective actions.

In February 2026, the EPA issued a final rule amending the CCR Legacy rule. The ruling extends deadlines for various regulatory actions and clarifies previous information regarding implementation of the rule. NSP-Minnesota is still evaluating the final rule, but anticipates impacts to be consistent with prior accruals.

Clean Water Act Section 316(b) — The Federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure they reflect the best technology available for minimizing impingement and entrainment of aquatic species.

NSP-Minnesota estimates capital expenditures of approximately \$45 million may be required to comply with the requirements. NSP-Minnesota anticipates these costs will be recoverable through regulatory mechanisms.

Environmental Requirements — Air

Clean Air Act NOx Allowance Allocations — In June 2023, the EPA published final regulations for ozone under the “Good Neighbor” provisions of the Clean Air Act that established NOx allowance budgets for fossil fuel-fired electric generating facilities in subject states. The final rule applies to generation facilities in Minnesota, as well as other states outside of our service territory. However, the plan is subject to both judicial and administrative stays.

Compliance with the published plan would require subject facilities to secure additional allowances, install NOx controls and/or develop a strategy of operations that utilizes the existing allowance allocations. While the financial impacts of the final rule are uncertain and dependent on market forces and anticipated generation, if the rule is implemented, NSP-Minnesota anticipates the annual costs could be significant but would be recoverable through regulatory mechanisms.

In January 2026, the EPA proposed Phase 1 of its reconsideration of the “Good Neighbor” rule. Under Phase 1, the agency would approve eight State Implementation Plans, including Minnesota, which were partially disapproved in 2023. NSP-Minnesota will continue to evaluate any additional phases of the reconsideration of this rule as they are published by the EPA.

AROs — AROs have been recorded for NSP-Minnesota’s assets. For nuclear assets, the ARO is associated with the decommissioning of NSP-Minnesota nuclear generating plants.

Aggregate fair value of NSP-Minnesota’s legally restricted assets for funding future nuclear decommissioning was \$3.9 billion and \$3.5 billion at Dec. 31, 2025 and 2024, respectively.

NSP-Minnesota’s AROs were as follows:

(Millions of Dollars)	2025				
	Amounts Incurred (a)		Cash Flow Revisions (b)		
	Jan. 1, 2025		Accretion		Dec. 31, 2025
Electric					
Nuclear	\$ 2,476	\$ —	\$ 127	\$ —	\$ 2,603
Wind	406	—	14	(12)	408
Steam and other production	139	7	6	(1)	151
Distribution	18	—	1	—	19
Natural gas					
Transmission and distribution	33	—	2	(2)	33
Other					
Common	1	—	—	—	1
Total liability	\$ 3,073	\$ 7	\$ 150	\$ (15)	\$ 3,215

(a) Amounts incurred pertain to obligations related to new solar facilities.

(b) In 2025, AROs were revised for changes in timing and estimates of cash flows. Wind was revised due to the repowering of two wind facilities.

(Millions of Dollars)	2024					
	Jan. 1, 2024	Amounts Incurred (a)	Amounts Settled	Accretion	Cash Flow Revisions (b)	Dec. 31, 2024
Electric						
Nuclear	\$ 2,107	\$ —	\$ —	\$ 106	\$ 263	\$ 2,476
Wind	424	—	—	15	(33)	406
Steam and other production	77	61	(6)	4	3	139
Distribution	17	—	—	1	—	18
Natural gas						
Transmission and distribution	32	—	—	2	(1)	33
Other						
Miscellaneous	1	—	—	—	—	1
Total liability	<u>\$ 2,658</u>	<u>\$ 61</u>	<u>\$ (6)</u>	<u>\$ 128</u>	<u>\$ 232</u>	<u>\$ 3,073</u>

(a) Amounts incurred pertain to CCR coal ash regulations and Sherco Solar 1 being placed in service.
(b) In 2024, AROs were revised for changes in timing and estimates of cash flows. Changes in the nuclear AROs were driven by updated assumptions in the nuclear triennial filing coupled with discount rate and escalation rate changes. Wind, steam, and other production AROs were revised due to the results of 2024 dismantling studies.

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, 2025. Therefore, an ARO has not been recorded for these facilities.

Nuclear

Nuclear Insurance — NSP-Minnesota's public liability for claims from any nuclear incident is limited to \$16.3 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has \$500 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$15.8 billion of exposure is funded by the Secondary Financial Protection Program available from assessments by the federal government.

NSP-Minnesota is subject to assessments of up to \$166 million per reactor-incident for each of its three reactors, for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$25 million per reactor-incident during any one year. Maximum assessments are subject to inflation adjustments.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from NEIL and EMANI for each of NSP-Minnesota's two nuclear plant sites. The coverage limits are \$2.8 billion for both Monticello and Prairie Island. NEIL also provides business interruption insurance coverage up to \$490 million and \$420 million at Monticello and Prairie Island, respectively, 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 \$21 million for business interruption insurance and \$38 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 Prairie Island nuclear plants, which consist of storage pools and dry cask facilities. In October 2023, the MPUC approved additional storage at the Monticello site to support extended operations to 2040. The decommissioning plan addresses the disposition of spent fuel at the end of the licensed life in 2050. In October 2025, the MPUC approved additional storage at the Prairie Island site to support extended operations to 2054.

Regulatory Plant Decommissioning Recovery — Decommissioning activities for NSP-Minnesota's nuclear facilities are planned to begin at the end of each unit's authorized retirement dates, which can be different than the currently approved NRC operating licenses. These decommissioning activities are planned to be completed at both facilities by 2101.

NSP-Minnesota's current operating licenses allow continued use of its Monticello nuclear plant until 2050 and its Prairie Island nuclear plant until 2033 for Unit 1 and 2034 for Unit 2. NSP-Minnesota's authorized retirement dates are 2040 for Monticello, 2033 for Prairie Island Unit 1 and 2034 for Prairie Island Unit 2. As of Dec. 31, 2025, the planned retirement dates of the Prairie Island Unit 1 and Unit 2 and Monticello were 2053, 2054 and 2050, based off the approved 2024-2040 Upper Midwest Resource Plan. These will be incorporated in decommissioning estimates once additional approvals have been received. Approvals are expected in the third quarter of 2026.

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 most recent triennial decommissioning study was filed in November 2024 and approved by the MPUC in May 2025.

Obligations for decommissioning are expected to be funded 100% by the external decommissioning trust fund. NSP-Minnesota had \$3.9 billion and \$3.5 billion of assets held in external decommissioning trusts at Dec. 31, 2025 and 2024, respectively.

See Note 9 to the financial statements for additional discussion.

Leases

ROU assets represent NSP-Minnesota's rights to use leased assets. The present value of future operating lease payments is recognized in current and noncurrent operating lease liabilities. The present value of future finance lease payments is included in other current liabilities and noncurrent finance lease liabilities. These amounts, adjusted for any prepayments or incentives, are recognized as ROU assets.

Leases with an initial term of 12 months or less are classified as short-term leases and are not recognized on the balance sheet.

Operating lease ROU assets:

(Millions of Dollars)	Dec. 31, 2025	Dec. 31, 2024
PPAs	\$ —	\$ 709
Other	166	166
Gross operating lease ROU assets	166	875
Accumulated amortization	(42)	(482)
Net operating lease ROU assets	<u>\$ 124</u>	<u>\$ 393</u>

Finance lease ROU assets:

(Millions of Dollars)	Dec. 31, 2025	Dec. 31, 2024
Generation facilities	\$ 1,254	\$ —
Accumulated amortization	(12)	—
Net finance lease ROU assets	<u>\$ 1,242</u>	<u>\$ —</u>

In the third quarter of 2025, certain PPAs for natural gas fueled generating facilities were amended, extending NSP-Minnesota's use of these plants to 2039 and 2048. The amended agreements qualify for classification as finance leases. As of Dec. 31, 2025, other current liabilities and non-current finance lease liabilities include \$37 million and \$1.2 billion of finance lease obligations for these amended PPAs, respectively. Prior to these amendments, the agreements were classified as operating leases.

Commitments under operating and finance leases as of Dec. 31, 2025 in Accounts 227 and 243:

(Millions of Dollars)	Operating Leases (a)	Finance Leases
2026	\$ 13	\$ 103
2027	13	103
2028	13	106
2029	12	107
2030	12	109
Thereafter	183	1,455
Total minimum obligation	246	1,983
Interest component of obligation	(119)	(742)
Present value of minimum obligation	\$ 127	\$ 1,241
Less current portion	(7)	(37)
Noncurrent operating lease liabilities	<u>\$ 120</u>	<u>\$ 1,204</u>
Weighted-average remaining lease term in years	25.8	17.3

(a) Amounts do not include PPAs accounted for as executory contracts and/or contingent payments, such as energy payments on renewable PPAs.

PPA finance lease payments are allocated between interest charges and depreciation and amortization on the statements of income. PPA operating lease payments are included in electric fuel and purchased power, and expense for other operating leases is included in operating expenses and electric fuel and purchased power.

Components of lease expense:

(Millions of Dollars)	2025	2024
Operating leases		
PPA capacity payments	\$ 62	\$ 96
Other operating leases (a)	16	15
Total operating lease expense	<u>\$ 78</u>	<u>\$ 111</u>
Finance leases		
Amortization of ROU assets	\$ 12	\$ —
Interest expense on lease liability	28	—
Total finance lease expense	<u>\$ 40</u>	<u>\$ —</u>

(a) Includes immaterial short-term lease expense.

Most of NSP-Minnesota's leases do not contain a readily determinable discount rate. Therefore, the present value of future lease payments is generally calculated using the estimated incremental borrowing rate at commencement of each lease (weighted average of 4.4%).

PPAs and Fuel Contracts

Non-Lease PPAs — NSP-Minnesota has entered into PPAs with other utilities and energy suppliers for purchased power to meet system load and energy requirements, 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 may also include capacity payments. Certain PPAs, accounted for as executory contracts with various expiration dates through 2040, contain minimum energy purchase commitments. Total energy payments on those contracts were \$77 million and \$186 million in 2025 and 2024, respectively.

Included in electric fuel and purchased power expenses for PPAs accounted for as executory contracts were payments for capacity of \$29 million and \$64 million in 2025 and 2024, respectively.

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

At Dec. 31, 2025, 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)	
2026		\$	15	\$	26
2027			13		26
2028			6		27
2029			6		27
2030			1		9
Thereafter			1		—
Total (b)		\$	42	\$	115
^(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 2026 and 2037. NSP-Minnesota is required to pay additional amounts depending on actual quantities delivered under these agreements.

Estimated minimum purchases for these contracts as of Dec. 31, 2025:

(Millions of Dollars)		Coal		Nuclear fuel		Natural gas supply		Natural gas storage and transportation	
2026		\$	115	\$	67	\$	114	\$	175
2027			23		148		2		133
2028			2		35		1		63
2029			—		129		—		43
2030			—		24		—		27
Thereafter			—		49		—		111
Total (a)		\$	140	\$	452	\$	117	\$	552

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

10. Other Comprehensive Income

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

(Millions of Dollars)		2025			
		Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total	
Accumulated other comprehensive loss at Jan. 1		\$ (6)	\$ (2)	\$	(8)
Other comprehensive income before reclassifications		\$ 4	\$ —	\$	4
Accumulated other comprehensive loss at Dec. 31		\$ (2)	\$ (2)	\$	(4)
(Millions of Dollars)		2024			
		Gains and Losses on Interest Rate Cash Flow Hedges	Defined Benefit Pension and Postretirement Items	Total	
Accumulated other comprehensive loss at Jan. 1		\$ (18)	\$ (2)	\$	(20)
Other comprehensive income before reclassifications		\$ 12	\$	\$	12
Accumulated other comprehensive loss at Dec. 31		\$ (6)	\$ (2)	\$	(8)

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, NSP-Wisconsin, Public Service Company of Colorado (PSCo) and Southwestern Public Service Company (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)		2025		2024	
Operating revenues:					
Electric		\$	482	\$	460
Gas			1		1
Operating expenses:					
Purchased power			68		65
Transmission expense			164		151
Other operating expenses — paid to Xcel Energy Services Inc.			775		710
Interest income			7		5
Interest expense			1		2

Accounts receivable and payable with affiliates at Dec. 31:

(Millions of Dollars)		2025		2024	
		Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin		\$ —	\$ 10	\$ —	\$ 28
PSCo		1	—	—	7
SPS		—	1	—	2
Other subsidiaries of Xcel Energy Inc.		2	97	1	62
		\$ 3	\$ 108	\$ 1	\$ 99

During 2025 and 2024, Xcel Energy Inc. repurchased certain of NSP-Minnesota’s first mortgage bonds. For more information about these repurchases, see Note 5.

12. Supplementary Cash Flow Data

(Millions of Dollars)		Year Ended Dec. 31	
		2025	2024
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)		\$ (378)	\$ (350)
Supplemental disclosure of non-cash investing transactions:			
Accrued utility plant additions		\$ 280	\$ 500
Inventory transfers to utility plant		48	41
Operating lease right-of-use assets		1,043	39
Allowances for funds used during construction		71	53

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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)	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 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				(1,428,692)	(18,447,509)		(19,876,201)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(76,249)	687,223		610,974		
3	Preceding Quarter/Year to Date Changes in Fair Value				(88,836)	11,334,468		11,245,632		
4	Total (lines 2 and 3)				(165,085)	12,021,691		11,856,606	792,840,564	804,697,170
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,593,777)	(6,425,818)		(8,019,595)		
6	Balance of Account 219 at Beginning of Current Year				(1,593,777)	(6,425,818)		(8,019,595)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				101,636	364,270		465,906		
8	Current Quarter/Year to Date Changes in Fair Value				(379,901)	3,796,525		3,416,624		
9	Total (lines 7 and 8)				(278,265)	4,160,795		3,882,530	903,512,230	907,394,760
10	Balance of Account 219 at End of Current Quarter/Year				(1,872,042)	(2,265,023)		(4,137,065)		

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	26,896,487,360	23,545,569,338	2,295,711,573				1,055,206,449
4	Property Under Capital Leases	1,365,389,206	1,109,431,738					255,957,468
5	Plant Purchased or Sold							
6	Completed Construction not Classified	4,520,567,528	3,620,441,707	395,368,588				504,757,233
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	32,782,444,094	28,275,442,783	2,691,080,161				1,815,921,150
9	Leased to Others							
10	Held for Future Use	25,026,162	8,284,789					16,741,373
11	Construction Work in Progress	1,956,682,871	1,588,452,898	64,115,397				304,114,577
12	Acquisition Adjustments	77,527,253	77,527,253					
13	Total Utility Plant (8 thru 12)	34,841,680,380	29,949,707,723	2,755,195,558				2,136,777,100
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	11,639,376,830	10,108,372,107	872,047,270				658,957,453
15	Net Utility Plant (13 less 14)	23,202,303,550	19,841,335,616	1,883,148,288				1,477,819,647
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	10,965,180,882	9,926,574,142	856,254,639				182,352,101
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	658,590,528	166,192,545	15,792,631				476,605,352
22	Total in Service (18 thru 21)	11,623,771,410	10,092,766,687	872,047,270				658,957,453
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	Amortization of Plant Acquisition Adjustment	15,605,420	15,605,420					

33	Total Accum Prov (equals 14) (22,26,30,31,32)	11,639,376,830	10,108,372,107	872,047,270				658,957,453
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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases			
Includes operating and finance leases in accordance with ASC Topic 842 and FERC Docket No. AI19-1-000. Account 101.1 Finance Lease Asset Operating Right of Use Asset Total			
		\$	1,241,572,391 123,816,815 1,365,389,206
(b) Concept: AmortizationOfOtherUtilityPlantUtilityPlantInService			
The amortization of other utility plant within account 111 includes the following:			
Intangible Plant Nuclear Production Plant Hydraulic Production Plant-Conventional Total Amort of Other Utility Plant - Electric		\$	172,234 162,800,640 3,219,671 166,192,545
(c) Concept: AmortizationOfPlantAcquisitionAdjustment			
The amortization of plant acquisition adjustment within account 115 includes the following:			
Other Production Transmission Total Amort of Plant Acquisition Adj - Electric		\$	15,499,975 105,445 15,605,420

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4	
NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)						
1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent. 2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.						
Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	1,457,757	30,461,754		31,088,973	830,538
3	Nuclear Materials	190,129,178	142,072,925		120,349,381	211,852,722
4	Allowance for Funds Used during Construction	16,659,842	14,803,059		11,328,003	20,134,898
5	(Other Overhead Construction Costs, provide details in footnote)	310,730	99,611		182,423	227,918
6	SUBTOTAL (Total 2 thru 5)	208,557,507	187,437,349		162,948,780	233,046,076
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	66,773,660	162,904,437		229,678,097	
9	In Reactor (120.3)	557,340,356	232,119,413		206,863,875	582,595,894
10	SUBTOTAL (Total 8 & 9)	624,114,016	395,023,850		436,541,972	582,595,894
11	Spent Nuclear Fuel (120.4)	2,658,192,690	(2,396,975)		(206,863,875)	2,862,659,590
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	3,093,699,820		(114,498,542)		3,208,198,362
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	397,164,393	580,064,224	114,498,542	392,626,877	470,103,198
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: NuclearFuelMaterialsAndAssembliesInStockAdditions
Consists of transfers from 120.1 , and direct trailing charges to asset after in-service
(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(e) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Classified to Account 120.2 and 120.3
(f) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions
Transferred to Account 120.3
(g) Concept: NuclearFuelAssembliesInReactorOtherReductions
Transferred to Account 120.4
(h) Concept: SpentNuclearFuelOtherReductions
Transferred to Account 120.3
(i) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabrication
Consists of Administrative and General Costs
(j) Concept: NuclearFuelAssembliesInReactor
Net Salvage Values (Line No: 15 to 16 Column: f) are not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982
(k) Concept: SpentNuclearFuel
Net Salvage Values (Line No: 15 to 16 Column: f) are not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
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 the 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) 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.							
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	266,007,804	3,519,521				269,527,325
4	(303) Miscellaneous Intangible Plant	281,718,857				(281,718,857)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	547,726,661	3,519,521			(281,718,857)	269,527,325
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	16,688,358				(1,255,172)	15,433,186
9	(311) Structures and Improvements	310,984,614	916,342	187,944		(28,104,276)	283,608,736
10	(312) Boiler Plant Equipment	1,390,685,447	18,047,601	2,495,468		(105,765,221)	1,300,472,359
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	279,569,663	5,308,624	68,244		(23,452,555)	261,357,488
13	(315) Accessory Electric Equipment	185,622,548	794,473	260,676		(3,800,438)	182,355,907
13.1	(315.1) Computer Hardware		91			12,001	12,092
13.2	(315.2) Computer Software					955,878	955,878
13.3	(315.3) Communication Equipment					36,823	36,823
14	(316) Misc. Power Plant Equipment	55,127,644	246,472	167,628		(4,500,945)	50,705,543
15	(317) Asset Retirement Costs for Steam Production	78,378,557		149,749	(1,354,202)	(2,656,825)	74,217,781
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,317,056,831	25,313,603	3,329,709	(1,354,202)	(168,530,730)	2,169,155,793
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,680,756					1,680,756
19	(321) Structures and Improvements	674,425,086	10,502,159	1,433,978			683,493,267
20	(322) Reactor Plant Equipment	2,161,485,794	90,605,413	14,112,480			2,237,978,727
21	(323) Turbogenerator Units	683,274,219	23,558,824	2,190,236			704,642,807
22	(324) Accessory Electric Equipment	563,872,685	16,475,312	4,292,392			576,055,605
22.1	(324.1) Computer Hardware		10,836,641	1,775,399		38,675,421	47,736,663
22.2	(324.2) Computer Software		2,812,014			152,877,057	155,689,071
22.3	(324.3) Communication Equipment			254,723		1,827,921	1,573,198
23	(325) Misc. Power Plant Equipment	213,417,997	1,482,750	223,115			214,677,632

24	(326) Asset Retirement Costs for Nuclear Production	(117,687,713)					(117,687,713)
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	4,180,468,824	156,273,113	24,282,323		193,380,399	4,505,840,013
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	1,693,076					1,693,076
28	(331) Structures and Improvements	1,553,187	186,658				1,739,845
29	(332) Reservoirs, Dams, and Waterways	11,767,228	6,309,641				18,076,869
30	(333) Water Wheels, Turbines, and Generators	10,156,576					10,156,576
31	(334) Accessory Electric Equipment	3,283,907					3,283,907
31.1	(334.1) Computer Hardware		261				261
31.2	(334.2) Computer Software						
31.3	(334.3) Communication Equipment						
32	(335) Misc. Power Plant Equipment	134,001					134,001
33	(336) Roads, Railroads, and Bridges	367,388	1,913				369,301
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	28,955,363	6,498,473				35,453,836
35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights		100,427			3,552,263	3,652,690
35.3	(338.2) Structures and Improvements		8,411,576			5,280,172	13,691,748
35.5	(338.4) Solar Panels		258,446,906			275,893,006	534,339,912
35.6	(338.5) Collector System		25,710,019				25,710,019
35.7	(338.6) Generator Step-up Transformers (GSU)		9,460,015				9,460,015
35.8	(338.7) Inverters		29,985,751			55,575,534	85,561,285
35.9	(338.8) Other Accessory Electrical Equipment		2,434,383				2,434,383
35.10	(338.9) Computer Hardware		81,426			237,418	318,844
35.11	(338.10) Computer Software		6,166,374				6,166,374
35.12	(338.11) Communication Equipment						
35.13	(338.12) Miscellaneous Power Plant Equipment		5,095,795			3,110,935	8,206,730
35.14	(338.13) Asset Retirement Costs for Solar Production		7,065,703			6,376,703	13,442,406
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)		352,958,375			350,026,031	702,984,406
35.16	E. Wind Production Plant						
35.17	(338.20) Land and Land Rights					29,935,596	29,935,596
35.18	(338.21) Structures and Improvements		20,509,535			304,185,776	324,695,311
35.20	(338.23) Wind Turbines		421,551,582	249,644,228		2,887,281,773	3,059,189,127
35.21	(338.24) Wind Towers and Fixtures		2,376,079			450,618,572	452,994,651
35.23	(338.26) Collector System		6,421,015			92,620,391	99,041,406
35.24	(338.27) Generator Step-up Transformers (GSU)		622,868				622,868
35.25	(338.28) Inverters						
35.26	(338.29) Other Accessory Electrical Equipment		2,628,613	78,790,573		134,174,178	58,012,218
35.27	(338.30) Computer Hardware		17,598			6,917,792	6,935,390
35.28	(338.31) Computer Software					3,793,403	3,793,403
35.29	(338.32) Communication Equipment		1,680,986			14,571,480	16,252,466

35.30	(338.33) Miscellaneous Power Plant Equipment				(66)	16,542,145	16,542,079
35.31	(338.34) Asset Retirement Costs for Wind Production				(12,051,209)	313,794,003	301,742,794
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)		455,808,276	328,434,801	(12,051,275)	4,254,435,109	4,369,757,309
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights					1,255,172	1,255,172
35.35	(339.2) Structures and Improvements		104,615			29,034,867	29,139,482
35.36	(339.3) Fuel Holders		1,488,602			12,325,206	13,813,808
35.37	(339.4) Boilers		6,217,340	427,295		94,087,216	99,877,261
35.39	(339.6) Generators		606,267			24,662,195	25,268,462
35.41	(339.8) Other Accessory Electrical Equipment		4,196,872			3,874,679	8,071,551
35.42	(339.9) Computer Hardware			38,034		88,577	50,543
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment		120,935			1,573,568	1,694,503
35.46	(339.13) Asset Retirement Costs for Other Renewable Production					2,656,825	2,656,825
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)		12,734,631	465,329		169,558,305	181,827,607
36	G. Other Production Plant						
37	(340) Land and Land Rights	37,177,008	8,284,789	52,000		(41,772,648)	3,637,149
38	(341) Structures and Improvements	530,642,966	3,055,632	1,201,244		(328,830,198)	203,667,156
39	(342) Fuel Holders, Products, and Accessories	32,181,080	1,301,659	1,483,135			31,999,604
40	(343) Prime Movers	152,819,666	2,786,377	111,995			155,494,048
41	(344) Generators	4,539,908,518	107,706,995	33,867,770		(3,617,313,649)	996,434,094
42	(345) Accessory Electric Equipment	426,868,981	2,275,541	1,622,593		(258,493,650)	169,028,279
42.1	(345.1) Computer Hardware		43,547			380,140	423,687
42.2	(345.2) Computer Software					218,018	218,018
42.3	(345.3) Communication Equipment					320,745	320,745
43	(346) Misc. Power Plant Equipment	67,525,389	1,227,989	449,372		(22,503,530)	45,800,476
44	(347) Asset Retirement Costs for Other Production	321,347,953				(320,170,706)	1,177,247
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	6,108,471,561	126,682,529	38,788,109		(4,588,165,478)	1,608,200,503
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	12,634,952,579	1,136,269,000	395,300,271	(13,405,477)	210,703,636	13,573,219,467 ⁽⁹⁾
47	3. Transmission Plant						
48	(350) Land and Land Rights	175,757,118	30,958,029				206,715,147
48.2	(351.1) Computer Hardware			168,198		880,037	711,839
48.3	(351.2) Computer Software		3,613,263			45,722,967	49,336,230
48.4	(351.3) Communication Equipment		14,887,036	2,538,550		118,751,620	131,100,106
49	(352) Structures and Improvements	173,089,618	14,960,432	114,060			187,935,990
50	(353) Station Equipment	1,683,390,084	140,853,100	1,525,779			1,822,717,405
51	(354) Towers and Fixtures	128,175,545	131,931	2,789,018		(720,225)	124,798,233
52	(355) Poles and Fixtures	1,805,325,840	123,145,099	9,146,243			1,919,324,696
53	(356) Overhead Conductors and Devices	858,984,220	88,882,027	12,912,865			934,953,382
54	(357) Underground Conduit	32,181,582	6				32,181,588

55	(358) Underground Conductors and Devices	35,641,688	2,035,441	21,201		720,225	38,376,153
56	(359) Roads and Trails	4,437,162	1,874,408				6,311,570
57	(359.1) Asset Retirement Costs for Transmission Plant	173,429					173,429
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,897,156,286	421,340,772	29,215,914		165,354,624	5,454,635,768
59	4. Distribution Plant						
60	(360) Land and Land Rights	20,519,639	931,396	19			21,451,016
61	(361) Structures and Improvements	71,499,760	3,146,222	78,326			74,567,656
62	(362) Station Equipment	881,663,896	56,657,127	334,100			937,986,923
63.1	(363.1) Computer Hardware			9,369,975		14,951,480	5,581,505
63.2	(363.2) Computer Software		12,386,350			48,296,064	60,682,414
63.3	(363.3) Communication Equipment		15,485,889	4,029,921		133,295,345	144,751,313
64	(364) Poles, Towers, and Fixtures	867,400,132	124,864,241	862,391			991,401,982
65	(365) Overhead Conductors and Devices	790,325,973	81,609,065	3,306,529			868,628,509
66	(366) Underground Conduit	438,122,032	9,848,737	751,267			447,219,502
67	(367) Underground Conductors and Devices	1,570,563,825	67,352,953	3,570,852			1,634,345,926
68	(368) Line Transformers	683,885,745	107,490,911	23,164,950			768,211,706
69	(369) Services	484,963,020	31,007,478	230,831			515,739,667
70	(370) Meters	316,312,557	30,007,421				346,319,978
71	(371) Installations on Customer Premises	17,754,848	2,625,658				20,380,506
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	106,971,085	9,282,335	111,739			116,141,681
74	(374) Asset Retirement Costs for Distribution Plant	12,231,038					12,231,038
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,262,213,550	552,695,783	45,810,900		196,542,889	6,965,641,322
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)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements						
84.4	(387.3) Energy Storage Equipment						
84.6	(387.5) Collector System						
84.7	(387.6) Generator Step-up Transformers (GSU)						
84.8	(387.7) Inverters						
84.9	(387.8) Computer Hardware						
84.10	(387.9) Computer Software						

84.11	(387.10) Communication Equipment						
84.12	(387.11) Miscellaneous Energy Storage Equipment						
84.13	(387.12) Asset Retirement Costs for Energy Storage						
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)						
85	7. General Plant						
86	(389) Land and Land Rights	21,425,906	2,216,081				23,641,987
87	(390) Structures and Improvements	171,385,310	85,648,697				257,034,007
88	(391) Office Furniture and Equipment	112,043,391	2,170,011	1,179,570		(82,763,121)	30,270,711
89	(392) Transportation Equipment	266,365,812	24,462,341	51,229,016			239,599,137
90	(393) Stores Equipment	1,984,820		207,295			1,777,525
91	(394) Tools, Shop and Garage Equipment	164,535,953	27,152,510	19,943,061			171,745,402
92	(395) Laboratory Equipment	2,663,856		1,243,655			1,420,201
93	(396) Power Operated Equipment	97,385,972	33,463,278	29,705,337			101,143,913
94	(397.1) Computer Hardware		4,019,596	10,244,997		20,777,145	14,551,744
94.1	(397.2) Computer Software		7,991,720			29,649,083	37,640,803
94.2	(397.3) Communication Equipment			6,134,324		28,589,308	22,454,984
95	(398) Miscellaneous Equipment	1,885,572		178,823			1,706,749
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,135,302,476	187,124,234	120,066,078		(299,373,469)	902,987,163
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)	1,135,302,476	187,124,234	120,066,078		(299,373,469)	902,987,163
100	TOTAL (Accounts 101 and 106)	25,477,351,552	2,300,949,310	590,393,163	(13,405,477)	(8,491,177)	27,166,011,045
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)	25,477,351,552	2,300,949,310	590,393,163	(13,405,477)	(8,491,177)	27,166,011,045

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
ELECTRIC PLANT LEASED TO OTHERS (Account 104)								
Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)		
1	N/A					0		
47	TOTAL							

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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	^(a) See Footnote				
3	Electric Production Angus Anson Peaking Plant-Land	12/01/2025	12/31/2031	8,284,789	
21	Other Property:				
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47	TOTAL				8,284,789

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: ElectricPlantHeldForFutureUseDescription			
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 for the plant in service balances included in the formula.			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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	SHC Solar Gen Plant III New-25233	374,969,855		
2	DO-MN-WFRM Sfty Settings LINE Discr	40,633,316		
3	DO-MN-WFRM OHPoleAssessment Mit Dis	27,460,306		
4	PI TN-40 Casks (48-64)	26,024,021		
5	MT 2nd License Renewal	25,323,077		
6	SHERCO 3 - Collector Sub	24,222,521		
7	MNEC QISG Contract	21,056,710		
8	0980 -Str 2 -27A (Phase 2)	20,676,429		
9	ELR MN Sub Feeder Breakers	20,559,824		
10	MT 2028 DFS Cask Campaign	19,031,408		
11	SHC2 Synch Condenser	18,874,919		
12	Garvin Substation - Phase 2	17,904,999		
13	MN Energy Connection Pre-Con	16,063,494		
14	RIV9 - Hot Gas Path - 22487	13,860,700		
15	CCV NSPM MN	13,550,479		
16	ITC-ADMS-OMS Merge Upgrade CE MN	13,356,946		
17	Lyon County CT Gen Plant	12,584,630		
18	FERC 881 ? Data Compliance	12,258,688		
19	LRTP2 BOA-New 345kV Sub	12,012,566		
20	C Extend Elm Creek ECK322	11,674,982		
21	Winona duct replacement	11,548,353		
22	LRTP 2 0954 345kV ALS-QRY	11,537,997		
23	RIV10 Hot Gas Path-22488	11,066,363		
24	MT Replace Stator Connection Ring	10,933,084		
25	Parkers Lake TR09	10,922,191		
26	PI 2nd License Renewal	10,871,838		
27	0736 SCA-LCR 69kV REBLD 9mi	10,431,079		
28	SHC1 Synch Condenser	10,272,415		
29	MT - WRGM Replacement	9,982,760		
30	SUB Reinf Daytons Bluff DBL Sub Ph2	9,489,306		
31	Dodge Center New SC	8,565,858		
32	MISO LRTP4 pre-con MN	8,264,500		
33	LINE Install Louise LOU TR2	8,215,999		
34	Install Network Monitoring Mpls	8,071,294		

35	Sunflower Substation - Phase 2	7,976,800
36	PI Water Treatment Mod	7,817,148
37	MN Transportation Units Over 50K	7,634,422
38	SUB Install Knight Sub	7,578,493
39	SUB Install Wagon Wheel LAC TR2	7,340,245
40	MN-Dist Fleet NewUnit Prchse EI Ops	7,339,588
41	SUB MN Feeder Load Monitoring	7,311,617
42	NSM0984 CNC SHC REPL STRS PH4	6,949,385
43	Relocate STP Tunnel Feeders	6,882,621
44	RRK - 115kV Ampacity Upgrade	6,832,215
45	SUB Install Stockyards STY TR03	6,388,716
46	ELR MN Sub TRs	6,327,900
47	Rebuild Daytons Bluff DBL Manholes	6,158,115
48	Rebuild Downtown St. Paul Manholes	5,935,253
49	NSM0808 Airport-E. Bloomington	5,844,359
50	NSM0992 CNC SHC REPL STRS PH4	5,534,479
51	0726 Curie tap-Tracy Switch St rebu	5,501,419
52	LAND Big Sioux River Substation Pur	5,470,932
53	SSB Sherco South BESS	5,371,175
54	J1040 Bison Sub SFNU	5,318,580
55	J1169 Grant Sub SFNU - SUB NU	5,219,549
56	LINE ELR Install Gaiter Lake Sub	5,111,724
57	0774 Line Rebuild Str. 444 to GVW	5,107,181
58	C Extend ALD071	5,070,901
59	ITC-EMS Tech stack Upgrade CE 20018	5,064,765
60	BDS5C Unit 5 Major Inspection	5,008,751
61	ITC-ECMS Nuclear SW MN	4,772,259
62	ITC-AOM OMS SW 200118 MN	4,694,059
63	0987 STR 105 - RRK 345 Rebuild	4,623,664
64	ITC-FERC 881 AAR Solution SW 200118	4,554,355
65	Relocate for I-494 expansion	4,478,870
66	5400 STR 182 ? RCH Rebuild	4,452,374
67	MN-Fleet ADD Units EI Trans >50K	4,378,760
68	LINE Convert Larimore LAR 4kV	4,309,138
69	NOB - INST 672MVA TR3 TAM SUB	4,306,336
70	BLB Blue Lake BESS	4,234,141
71	C Install Elm Creek ECK342 Feeder	4,230,771
72	Monticello TR6 - 336MVA	4,027,778
73	Montevideo Fleet Outbuliding	3,811,812
74	LRTP 2 5656 345kV ALS-RVV	3,803,890
75	T PIP090 feeder underbuild 2nd	3,779,268

76	Install Edina EDA063 Feeder	3,624,121
77	Monticello TR10 - 336MVA	3,615,991
78	OT Asset Monitoring SW NSPM	3,478,118
79	Pot Parallel Prairie Island 345kV	3,466,363
80	0760 WAB LAK STR181-217 RBLD	3,438,975
81	MISO LRTP Tranche 2 Pre-Con NSPM	3,433,827
82	MN Failed Sub Equip Replacement	3,416,342
83	MN Failed Sub TR Replacement	3,395,723
84	HBC8 Hot Gas Path-26001	3,277,080
85	ITC-PI Sec Comp Refresh NP MN	3,257,714
86	ITC-AOM Servers HW MN	3,208,374
87	5526 RLK-LOK Refurb	3,174,744
88	ITC-Nuclear OWM 360 View SW MN	3,138,538
89	0987 PRI ? STR 105 345 Rebuild	3,091,863
90	0986 STR 104 - RRK 345 Rebuild	3,075,137
91	ELR STP Network Protectors	3,050,901
92	NSPM S&E 69kV Line	3,033,938
93	Composite Mats MN	2,995,804
94	DO-SD-WFRM Sfty Settings LINE Discr	2,992,988
95	Glenwood Cap Banks TAM	2,970,298
96	PI SR Inverter Replacement	2,929,781
97	Split Rock (SPK) Congestion Upgrade	2,912,851
98	ITC-MEC 2.0 SW 200117 MN	2,896,977
99	Reinforce Twin Lakes TWL081	2,877,097
100	Reserve TR 115-13.8 kV 50 MVA	2,871,057
101	Line 5660 GRV ? SFR	2,859,297
102	SHC3-U3 Replace L-0 Buckets 27689	2,851,169
103	NSPM Field Operations Replacements	2,837,620
104	RRK 115kV ELR Breakers	2,798,378
105	Garvin Substation - Phase 1	2,794,834
106	Reserve TR 115-13 kV 28 MVA	2,759,035
107	0742 IVG-WNG 69kV RBLD 2.5mi	2,736,746
108	YLM211 and YLM212 Rebuild OH lines	2,721,405
109	SHC FE Long Duration Battery-26451x	2,709,629
110	Reserve TR 115-13.8 kV 50 MVA	2,686,183
111	MT 2026 ISFSI Expansion	2,676,970
112	T SUB Rebuild Cap Banks GLD Sub	2,570,635
113	5519 HUG-WYO Refurbishment	2,570,255
114	MN-Dist Fleet New Unit Purchase E >	2,470,235
115	NSM0892 BCK RRK REBLD STRS 14 TO 20	2,458,311
116	NSPM Week4 SES Accrual	2,390,014

117	0986 PRI ? STR 104 345 Rebuild	2,388,197
118	Relocate BCR fdrs 82,81,62, 63	2,289,506
119	Black Dog BRK's 5M254, 5M257, 5M258	2,281,467
120	SUB Install Prior PRR TR2	2,255,215
121	C Extend WDY311	2,184,152
122	MN - Pole Replacement Blanket	2,176,365
123	LYC - Inst 3 - 345kV Brkrs	2,169,841
124	Stockyards DCP TR3 Sub	2,164,513
125	Reserve TR 67-13.8 kV 25 MVA	2,163,351
126	MT LP-B Bucket and Pin Repl	2,155,737
127	Riverside U7 Recovery	2,149,210
128	Reserve TR 69-13.8 kV 28 MVA	2,144,982
129	SWB SHC0-Sherco West BESS-29047	2,135,179
130	Pipestone TR05	2,123,416
131	MT #12 EDG Voltage Regulator	2,087,793
132	BLL - Comm Upgrade	2,033,125
133	MT Traveling Screen Upgrade	2,021,707
134	Relocate RED091 8th ST	2,008,380
135	COMM MN Feeder Load Monitoring	2,007,494
136	C Relocate 3900 MNTNKA BLVD OH-UG	1,991,543
137	RIV7-U7 HP R1 Blade Repl-New -23786	1,984,833
138	NSPM S&E 115kV Line	1,982,782
139	C Extend SMT061	1,961,131
140	Astro Substation TAM	1,949,575
141	Relocate SMT072 LAE061 for Hwy 22	1,946,611
142	SUB Reinforce Fair Park FAP TR2	1,934,953
143	Rebuild Red River RED Feeders	1,907,178
144	Garvin Substation - Land	1,877,544
145	LINE Install Glenwood GLD Feeder	1,876,925
146	MN LED Post Top Conversion	1,847,683
147	NSM0782 GNL-GSL Rebuild	1,846,643
148	NSPM PHEV >\$50K Distribution Electr	1,784,657
149	DO-NSPM Capital Optimization Model	1,776,381
150	Reserve TR 115/13.8 kV 28 MVA	1,758,753
151	Sioux Falls Renovation - Phase II	1,748,895
152	MT AST SSR Isolation	1,738,676
153	PI-NMC RD Rad Monitor Repl	1,729,154
154	MN SUB Analog Circuit Retirements	1,728,137
155	Pot Parrallel Removal RRK 115kV	1,725,718
156	NSM0893 BCK RRK REBLD STRS 14 TO 20	1,716,957
157	NSM0859 Str. 16 to Chemolite Rebuil	1,715,116

158	AMI-SW-License-BS-NSPM-NEW	1,710,756
159	Install Feeder Tie RMT322-RMT311	1,709,464
160	LINE Install South Renner SRN TR02	1,703,666
161	NSPM Priority Defects 115kV, Line	1,699,099
162	ITC-PI Prcess Cmpute Upgrd HW MN	1,688,866
163	SUB: Install New Rapidan Area Subst	1,664,930
164	LINE Reinf Dayton's Bluff DBL Sub	1,638,100
165	MT V-AC-1 A/B Cooling Unit Repl	1,625,833
166	J1826 CTF Interc SF-NU SUB	1,615,229
167	0890 GRC-XRD 115kV REBLD 5MI	1,615,099
168	LINE Reinforce Hyland Lake HYL TRs	1,579,661
169	PI DFS +20yr incl CON	1,568,021
170	ELR MN Sub Switches	1,537,845
171	Replace FLS064 8th-10th S Phillips	1,535,612
172	T DLO-WTN-STB Del to St Boni	1,515,665
173	0718 Arlington to Winthrop Rebuild	1,497,087
174	ELR MPLS Vault Tops	1,496,994
175	SUB Install Glenwood GLD Feeder	1,492,591
176	MINNESOTA MAJOR STORM RECOVERY	1,464,999
177	ITC-PI Security SW MN	1,452,459
178	MN Electric Vehicle Program FLEET	1,430,011
179	Relocation MPLS SWLRT Road Project	1,427,418
180	Relocate MHW312 Sartell	1,414,457
181	0982 CDL-Str 105 (Ln 0967) Rebuild	1,397,415
182	SE Region Reliability Initiative	1,394,291
183	Monticello MOD Installation	1,388,444
184	0736 SCA-STR270 69kV REBLD 5mi	1,373,727
185	0721 Rebuild STR 0721-71 ? CAI 69kV	1,363,204
186	RIV Emergent Fund -Other prod	1,338,672
187	0887 (SCL - GRC) - Private Comm Net	1,321,610
188	MN RMP - Battery Installations	1,315,284
189	SUB Reinf Dayton's Bluff DBL Sub Ph3	1,308,252
190	0891 WSC-XRD 115kV REBLD 4MI	1,302,800
191	PI ERCS System Upgr-DAS & RMUs	1,297,461
192	Line 5658 SFR ? SSW	1,288,896
193	SHC3C Emergent work	1,277,092
194	ELR MPLS Network Protectors	1,255,709
195	Rebuild Slayton SLW062 drone v2	1,250,290
196	LRTP 2 5657 345kV BOA-RVV	1,247,443
197	Wagon Wheel Interconnect	1,247,056
198	JT Extension Umore	1,246,814

199	NSM0782 WSG- GNL Rebuild	1,239,696
200	PI 2025 Capital Maintenance	1,233,268
201	WLM Emergent Fund -Steam prod	1,205,136
202	NSPM NSPM ELR - RTU,Comm	1,202,704
203	King Transm Connection NSPM Pre Con	1,199,466
204	C Relocate SMT61 Mankato	1,193,777
205	ANS Emergent Fund -Other prod	1,180,368
206	Relocate WWK321 (Hwy 212)	1,177,337
207	Envis - Pre-Con	1,176,646
208	0737 Rebuild Gleason Lake to Mound	1,175,594
209	MN Thread Software WIND	1,170,547
210	BOA 345kV Sub, COMM	1,164,927
211	FLISR - AGIS - MN	1,163,857
212	SUB Convert Gaylord GAY 4kV	1,163,768
213	Relocate LCO071 (Veterans Pkwy)	1,162,755
214	MT Security Microwave Head Repl	1,162,113
215	Monticello (MNN) Congestion Upgrade	1,161,465
216	ITC-Grid DERMS CME 200118 MN	1,122,465
217	SBD Add Distribution	1,119,003
218	Rebuild Cannon City Blvd poles	1,114,572
219	PRI Sub Rbld-Construct Phase 01	1,108,174
220	C Harrisburg LCO072 OH-UG	1,102,124
221	Rebuild multiple DBL ducts	1,098,697
222	RED ROCK - LZOP - 115KV_0892_BCK2	1,076,636
223	PI 2023 Capital Maintenance	1,075,362
224	FCR MEL082	1,054,019
225	PI Plant Restrooms and Locker Rooms	1,042,419
226	0979 345kV Clearance Correction	1,038,017
227	MN-Chestnut Reconstruction	1,037,784
228	0772 Prairie to MNPC Rebuild	1,016,792
229	Knight Substation TAM	1,014,047
230	ELR MN Sub Fences	1,011,803
231	JT Summer Valley	1,011,474
232	Minor Projects	178,766,256
233	(a) (footnote to page 106)	
43	Total	1,588,452,898

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: ConstructionWorkInProgressProjectDescription			
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 Commission approved transmission projects.			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property. 3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications. 4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.							
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)		
Section A. Balances and Changes During Year							
1	Balance Beginning of Year	9,533,095,160	9,533,095,160				
2	Depreciation Provisions for Year, Charged to						
3	(403) Depreciation Expense	884,556,888	884,556,888				
4	(403.1) Depreciation Expense for Asset Retirement Costs	7,550,101	7,550,101				
5	(413) Exp. of Elec. Plt. Leas. to Others						
6	Transportation Expenses-Clearing	32,901,496	32,901,496				
7	Other Clearing Accounts	157,569	157,569				
8	Other Accounts (Specify, details in footnote):						
9.1	Other Accounts (Specify, details in footnote):						
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	925,166,054	925,166,054				
11	Net Charges for Plant Retired:						
12	Book Cost of Plant Retired	(590,243,417)	(590,243,417)				
13	Cost of Removal	(92,965,036)	(92,965,036)				
14	Salvage (Credit)	14,190,305	14,190,305				
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(669,018,148)	(669,018,148)				
16	Other Debit or Cr. Items (Describe, details in footnote):						
17.1	Other Debit or Cr. Items (Describe, details in footnote):	137,480,825	137,480,825				
18	Book Cost or Asset Retirement Costs Retired	(149,749)	(149,749)				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	9,926,574,142	9,926,574,142				
Section B. Balances at End of Year According to Functional Classification							
20	Steam Production	1,771,550,227	1,771,550,227				
21	Nuclear Production	2,799,679,370	2,799,679,370				
22	Hydraulic Production-Conventional	22,394,273	22,394,273				
23	Hydraulic Production-Pumped Storage						
23.1	Solar Production	15,427,129	15,427,129				
23.2	Wind Production	416,106,838	416,106,838				
23.3	Other Renewable Production	169,035,053	169,035,053				
24	Other Production	720,205,718	720,205,718				
25	Transmission	1,384,598,816	1,384,598,816				
26	Distribution	2,331,406,578	2,331,406,578				
27	Regional Transmission and Market Operation						

27.1	Energy Storage	1,339,310	1,339,310		
28	General	294,830,830	294,830,830		
29	TOTAL (Enter Total of lines 20 thru 28)	9,926,574,142	9,926,574,142		

FOOTNOTE DATA		
(a) Concept: OtherAdjustmentsToAccumulatedDepreciation		
Net change in RWIP	\$	(29,953,660)
Net Transfers and Adjustments		167,404,593
(Gain)/Loss		33,359
Common Expense Allocation		(3,467)
Total	\$	137,480,825
(b) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant		
	Cost of Removal Reserve	
Steam Production	\$	156,612,920
Nuclear Production		(64,761,998)
Hydraulic Production-Conventional		4,302,841
Other Production		44,220,454
Wind Production		87,377,653
Electric Other Renewable Production		31,756,701
Electric Energy Storage		1,339,310
Transmission		193,250,307
Distribution		280,334,048
General		3,083,431
Total	\$	737,515,667
(c) Concept: AccumulatedDepreciationSteamProduction		
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.		
(d) Concept: AccumulatedDepreciationNuclearProduction		
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.		
(e) Concept: AccumulatedDepreciationHydraulicProductionConventional		
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.		
(f) Concept: AccumulatedDepreciationSolarProduction		
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.		
(g) Concept: AccumulatedDepreciationWindProduction		
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.		
(h) Concept: AccumulatedDepreciationOtherRenewableProduction		
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.		
(i) Concept: AccumulatedDepreciationOtherProduction		
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.		
(j) Concept: AccumulatedDepreciationTransmission		
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.		
(k) Concept: AccumulatedDepreciationTransmission		
Transmission Serving Production	\$	57,544,218
(l) Concept: AccumulatedDepreciationDistribution		
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.		
(m) Concept: AccumulatedDepreciationDistribution		
Distribution Serving Production	\$	3,028,643
(n) Concept: AccumulatedDepreciationEnergyStorage		

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.

[\(Q\)](#) Concept: AccumulatedDepreciationGeneral

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.

[\(P\)](#) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

<i>Cost of Removal Reserve</i>		
Steam Production	\$	156,612,920
Nuclear Production		(64,761,998)
Hydraulic Production-Conventional		4,302,841
Other Production		44,220,454
Wind Production		87,377,653
Electric Other Renewable Production		31,756,701
Electric Energy Storage		1,339,310
Transmission		193,250,307
Distribution		280,334,048
General		3,083,431
Total	\$	737,515,667

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)								
1. Report below investments in Account 123.1, Investments in Subsidiary Companies. 2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal. 3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1. 4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge. 5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number. 6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year. 7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different 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.								
Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	UNITED POWER & LAND CO.			14,280,160	983,618	92	15,263,686	
2	UNITED POWER & LAND CO. - Capital Stock			4,020,000			4,020,000	
3	UNITED POWER & LAND CO. - Paid-In-Capital			749,376		92	749,284	
4	UNITED POWER & LAND CO. - Unappropriated Undistributed Subsidiary Earnings			9,510,784	983,618		10,494,402	
5	NSP NUCLEAR CO.			1,579,449	(312)	15	1,579,122	
6	NSP NUCLEAR CO. - Capital Contribution			962,774		15	962,759	
7	NSP NUCLEAR CO. - Unappropriated Undistributed Subsidiary Earnings			616,675	(312)		616,363	
42	Total Cost of Account 123.1 \$5,732,043.00		Total	15,859,609	983,306	107	16,842,808	

FOOTNOTE DATA
(a) Concept: InterestAndDividendRevenueFromInvestments
Annual allocation of unitary tax (benefit)/detriment.
(b) Concept: InterestAndDividendRevenueFromInvestments
Annual allocation of unitary tax (benefit)/detriment.

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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)	81,648,991	72,808,690	Electric & Gas	
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)	^(a) 71,606,663	^(a) 86,883,015	Electric & Gas	
6	Assigned to - Operations and Maintenance				
7	Production Plant (Estimated)	165,226,526	168,983,501	Electric	
8	Transmission Plant (Estimated)	1,100,272	1,507,831	Electric	
9	Distribution Plant (Estimated)	4,632,023	8,188,573	Electric & Gas	
10	Regional Transmission and Market Operation Plant (Estimated)				
10.1	Energy Storage Plant (Estimated)				
11	Assigned to - Other (provide details in footnote)	^(a) (10,855,771)	^(a) (5,279,758)		
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	231,709,713	260,283,162		
13	Merchandise (Account 155)	1,331,042	2,124,680	Electric	
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	^(a) (footnote to page 106)				
20	TOTAL Materials and Supplies	314,689,746	335,216,532		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4		
FOOTNOTE DATA					
(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction					
Production	\$	Electric	25,748,613 \$	Gas	—
Transmission			17,054,201		—
Distribution			26,540,163		2,263,686
Total	\$		69,342,977 \$		2,263,686
(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction					
Production	\$	Electric	33,842,849 \$	Gas	—
Transmission			14,026,329		—
Distribution			27,673,841		11,339,996
Total	\$		75,543,019 \$		11,339,996
(c) Concept: PlantMaterialsAndOperatingSuppliesOther					
Includes a credit of \$2,777,165 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$8,078,606 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.					
(d) Concept: PlantMaterialsAndOperatingSuppliesOther					
Includes a credit of \$2,752,049 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$2,527,709 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance, and inventory held for sale.					
(e) Concept: DescriptionOfMaterialsAndSuppliesOtherClasses					
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).					

[illegible]

28	Total												
29	Balance-End of Year	1,471,705	200,000	109,269		69,262		69,262		1,870,074		3,589,572	200,000
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		926		926		926		35,137		38,841	
37	Add: Withheld by authoritative agency												
38	Deduct: Returned by authoritative agency												
39	Cost of Sales	926								926		1,852	
40	Balance-End of Year			926		926		926		34,211		36,989	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	926	9							926	10	1,852	19
45	Gains		9								10		19
46	Losses												

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: AllowancesInventoryPurchasesTransfersDescription			
Information not available at time of filing.			
(b) Concept: AllowancesInventoryPurchasesTransfersDescription			
Information not available at time of filing.			
(c) Concept: AllowancesReturnedByEnvironmentalProtectionAgencyNumber			
Final EPA information was unavailable at time of filing for line 5.			

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)		
				Account Charged (d)	Amount (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								
20	TOTAL							

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)	
				Account Charged (d)	Amount (e)		
21	(a) Prairie Island Extended Power Uprate Project MN Docket E-002/CN-08-509	(b) 78,884,915		(d) Various	3,952,254	33,909,813	
22	(a) Benson Biomass PPA Termination MN Docket E-002/M-17-530 ND Docket PU-17-270 and SD Docket EL 18-027	48,044,295		407	4,677,899	12,811,394	
49	TOTAL	126,929,210			8,630,153	46,721,207	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4									
FOOTNOTE DATA												
(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts 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. In its 2021 North Dakota retail electric rate case settlement under PU-20-441, NSP-Minnesota received recovery of approximately \$4 million of deferred costs plus a return, to be recovered over 13.3 years. In its 2023 South Dakota electric rate case under EL22-017, NSP-Minnesota received recovery of approximately \$4 million of deferred costs with a return to be recovered over a 11.3 year period beginning Jan. 1, 2023.												
(b) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts 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). Recovery ordered through the South Dakota Infrastructure Rider, Docket No. EL18-040 (Dec. 18, 2018). 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.												
(c) Concept: UnrecoveredPlantAndRegulatoryStudyCostsNotYetRecognized <table><tr><td>Transfers from Account No. 107 during 2012</td><td>\$</td><td>77,690,096</td></tr><tr><td>Transfers from Account No. 107 during 2013</td><td></td><td>1,194,819</td></tr><tr><td></td><td>\$</td><td>78,884,915</td></tr></table>				Transfers from Account No. 107 during 2012	\$	77,690,096	Transfers from Account No. 107 during 2013		1,194,819		\$	78,884,915
Transfers from Account No. 107 during 2012	\$	77,690,096										
Transfers from Account No. 107 during 2013		1,194,819										
	\$	78,884,915										
(d) Concept: UnrecoveredPlantAndRegulatoryStudyCostsWrittenOffAccountCharged <table><tr><td>Account No. 407 - amortization</td><td>\$</td><td>4,217,515</td></tr><tr><td>Account No. 426.5 - accretion</td><td></td><td>(265,261)</td></tr><tr><td></td><td>\$</td><td>3,952,254</td></tr></table>				Account No. 407 - amortization	\$	4,217,515	Account No. 426.5 - accretion		(265,261)		\$	3,952,254
Account No. 407 - amortization	\$	4,217,515										
Account No. 426.5 - accretion		(265,261)										
	\$	3,952,254										

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
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	Polaris Project - Becker	29,132	561.6,408.1,925,926				
3	Falcon Project	111,328	561.6,408.1,925,926				
4	Ryan Companies - Pine Island SISA	27,616	561.6,408.1,925,926				
5	Project Gemini - System Impact Study	13,869	561.6,408.1,925,926	50,000	561.6,408.1,925,926, 242		
6	SISA for City of Buffalo Substation No 2	2,146	561.6,408.1,925,926	10,000	561.6,408.1,925,926, 242		
7	Kimley Horn Interconnection Requests	604	561.6,408.1,925,926	76,180	561.6,408.1,925,926, 242		
8	GRE Century Interc Req	1,395	561.6,408.1,925,926				
9	Falcon Project	121	561.6,408.1,925,926				
10	Sleepy Eye SISA	1,447	561.6,408.1,925,926	20,000	561.6,408.1,925,926, 242		
11	NorthPoint Development	1,017	561.6,408.1,925,926	3,057	561.6,408.1,925,926, 242		
12	Ryan Companies US - Project Skyway - FSA	228,385	561.6,408.1,925,926	250,000	561.6,408.1,925,926, 242		
13	Cottage Grove - FSA	228,082	561.6,408.1,925,926	150,000	561.6,408.1,925,926		
14	SISA - Northfield (South Lot)	60,800	561.6,408.1,925,926	65,000	561.6,408.1,925,926, 242		
15	Gemini Data Center FAC Study Agrmt	14,290	561.6,408.1,925,926	250,000	561.6,408.1,925,926, 242		
16	FSA - City of Buffalo-Substation No. 2			85,000	242		
17	J2501 Pine Island Solar	14,390	561.6,408.1,925,926				
18	Project Magic SISA (Retail)			36,000	242		
19	Project Monte Cristo SISA (Retail)			36,000	242		
20	J2601 Catchfly BESS	16,372	561.6,408.1,925,926				
21	J2563 Odell Wind	17,538	561.6,408.1,925,926				
22	J2550 Schiller Storage	13,419	561.6,408.1,925,926				
23	J3021 Coneflower Energy	89,792	561.6,408.1,925,926				
24	City of Kasson - SISA	1,037	561.6,408.1,925,926	20,000	561.6,408.1,925,926, 242		
25	J3219 Byllesby Hydroelectric Project	8,466	561.6,408.1,925,926				
26	J2561 Schiller Solar Farm	12,717	561.6,408.1,925,926				
27	J2879 Cottage Grove Storage	62,571	561.6,408.1,925,926				
28	J2599 Nuthatch Solar	94,536	561.6,408.1,925,926				
29	Blue Earth SISA	2,773	561.6,408.1,925,926				
30	System Impact Study Agmt (SISA)-Madelia	2,017	561.6,408.1,925,926				
31	Sys Impact Study Agmt (SISA)-Sioux Falls	1,122	561.6,408.1,925,926				

32	J3163 Bison Generating Station	10,461	561.6,408.1,925,926		
33	J3213 Riverside Modernization Project	72,734	561.6,408.1,925,926		
34	J2447 Plum Creek III	35,474	561.6,408.1,925,926		
35	J2332 Plum Creek I	37,847	561.6,408.1,925,926		
36	J2716 Monarch Storage	71,732	561.6,408.1,925,926		
37	J2346 Plum Creek II	38,494	561.6,408.1,925,926		
38	FSA - Shamrock	159,551	561.6,408.1,925,926	250,000	561.6,408.1,925,926, 242
39	CHS	3,338	561.6,408.1,925,926		
20	Total	1,486,613		1,301,237	
21	Generation Studies				
22	J2309 Facility Study			64,898	242
23	DER Trans System Impact Study Q3 - NSPM	26,714	561.7,408.1,925,926		
24	Byron - GRE PL Valley NU Facility Study	14,400	561.7,408.1,925,926		
25	LEN062 USS Lennox Solar Garden FS	7,247	561.7,408.1,925,926		
26	J1605 Sherburne 345kV Facilities Study	1,190	561.7,408.1,925,926		
27	J1588 Bison 345kV Facilities Study	1,689	561.7,408.1,925,926		
28	J1445 Mayhew Lake Sub Solar	2,087	561.7,408.1,925,926		
29	J1040 Bison Capbank NU FaS	921	561.7,408.1,925,926		
30	J1605 Sherburne 345kV Short Circuit	266	561.7,408.1,925,926		
31	J1588 Bison 345kV Short Circuit	2,014	561.7,408.1,925,926		
32	J2053 Facility Study			4,924	242
33	J1898 Facility Study			6,781	242
34	J2065 Facility Study			53,320	242
35	J2104 Facility Study	185	561.7,408.1,925,926	101,744	561.7,408.1,925,926, 242
36	DER System Impact Study Q2	27,244	561.7,408.1,925,926		
37	DER System Impact Study Q1	24,538	561.7,408.1,925,926		
38	VRM061 05305992 Solar Garden FS	5,277	561.7,408.1,925,926		
39	Brookings County Substation ICIF MISO	15,456	561.7,408.1,925,926	15,456	561.7,408.1,925,926
40	J1045 FTN-CHB Line #5537 on J874	536	561.7,408.1,925,926		
41	J1495 North Rochester Facilities Study	523	561.7,408.1,925,926		
42	DER System Impact Study Q3	20,168	561.7,408.1,925,926		
43	J2199 Short Circuit Study	17	561.7,408.1,925,926		
44	MISO Facility Study Orders	111,553	561.7,408.1,925,926		
45	J732 Stone Lake-Transformer Replace	1,049	561.7,408.1,925,926		
39	Total	263,074		247,123	
40	Grand Total	1,749,687		1,548,360	

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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		Balance at end of Current Quarter/Year (f)		
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)			
1	Asset Retirement Recovery	2,926,385,157	157,376,273			3,083,761,430		
2	Benefit Cost Recovery Deficit	336,495,001	5,260,254	184	20,429,102	321,326,153		
3	Benson Biomass PPA Termination - MN Docket E-002/GR-17-530 - ND Docket PU-17-271 - SD Docket EL 18-027 - Generally amortized through 2028	18,383,764		557	4,913,132	13,470,632		
4	Costs to Relocate Facilities Underground - MN Docket E-002/M-99-799 - MN Docket E-002/M-04-1663 - Generally amortized over 36 months	862,222	40,239	142	345,200	557,261		
5	Deferred Nuclear Outage Costs - Generally amortized over 23-24 months - MN Docket E-002/M-07-1489 - ND Docket PU-07-774 - SD Docket EL 07-035	71,404,753	^(a) 76,697,993	^(b) Various	69,621,007	78,481,739		
6	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	372,070		282	261,180	110,890		
7	Derivatives & Hedging – Retail Electric & Gas	741,657	2,130,065			2,871,722		
8	Mankato/Cannon Falls Lease Normalization	17,171,561	207,000	101.1	17,378,561			
9	Minnesota Capacity Revenue Tracker- MN Docket E-002/GR-21-630	107,423,187		182.3	107,423,187			
10	Minnesota Electric Vehicle Tariff - MN Docket E-002/M-15-111 - MN Docket E-002/M-17-817 - MN Docket E-002/M-18-643 - MN Docket E-002/M-19-186 - MN Docket E-002/M-20-711 - MN Docket E-002/GR-21-630	1,632				1,632		
11	Minnesota Electric Sales True-Up - 2023 - MN Docket E-002/GR-21-630	12,547,430		407.3	12,547,430			
12	Minnesota Electric Sales True-Up - 2024 - MN Docket E-002/GR-21-630	39,590,623	108,690,132	407.3	90,443,619	57,837,136		
13	Minnesota Electric State Energy Policy Rider - MN Docket E-002/M-23-465	1,248,328	14,440	407.4	6,067	1,256,701		
14	Minnesota Gas Utility Infrastructure Cost Rider - MN Docket G-002/M-25-402	29,539,397	14,631,814	407.3	19,018,135	25,153,076		
15	Minnesota Deferred Electric Property Tax - 2025 - MN Docket E-002/GR-21-630		2,772,361			2,772,361		
16	Minnesota Deferred Gas Property Tax - 2022 - MN Docket G-002/GR-21-678	24,841		408.1	20,445	4,396		
17	Minnesota Deferred Gas Property Tax - 2023 - MN Docket G-002/GR-21-678	1,233,233	38,742	408.1	1,062,466	209,509		
18	Minnesota Deferred Gas Property Tax - 2024 - MN Docket G-002/GR-21-678	2,083,713	848,702	408.1		2,932,415		
19	Minnesota Deferred Gas Property Tax - 2025 - MN Docket G-002/GR-23-413		6,476,385			6,476,385		
20	Minnesota Gas Conservation and Energy Management Program Costs - MN Docket G-002/M-25-47 - Generally amortized over 12 month period following the expenditure	2,956,090	40,671,050	^(c) Various	43,627,140			
21	Minnesota Gas Decoupling - MN Docket G-002/GR-23-413	30,860,169	4,771,382	407.3	17,822,445	17,809,106		
22	Minnesota Renewable Development Fund Rider - MN Docket E-002/M-25-370	32,262,656	34,322,711	407.3	31,781,373	34,803,994		
23	Minnesota Renewable Energy Standard Rider- MN Docket E-002/M-25-400		56,155,216	407.3	54,230,195	1,925,021		
24	Minnesota Transmission Cost Recovery Rider- MN Docket E-002/GR-25-386		68,560,990	407.3	63,864,165	4,696,825		
25	Net of Tax AFUDC in Plant Adjustments	136,614,528	13,175,140			149,789,668		
26	Nonplant Excess ADIT	95,754,831		283	8,419,241	^(d) 87,335,590		
27	North Dakota AGIS Deferral - ND Docket PU-20-441	4,338,284	17,373	407.3	191,264	4,164,393		
28	North Dakota Environmental Cleanup - ND Docket PU-17-894		21,988	182.3	10,584	11,404		
29	North Dakota Renewable Energy Rider - ND Docket PU-25-248	310,778	4,032,414	407.4	4,286,335	56,857		

30	North Dakota PI Payments - ND Docket PU-23-364	517,435		524	517,435	
31	North Dakota Transmission Cost Recovery Rider - ND Docket PU-25-257	532,605	5,230,574	407.4	4,685,042	1,078,137
32	Nuclear Prevailing Wage Analysis		390,287			390,287
33	Power Contract Valuation Adjustment - Generally amortized over term of related contract	22,157,994		244	6,121,263	16,036,731
34	Renewable*Connect Government - MN Docket E-002/GR-24-147		7,080			7,080
35	Renewable*Connect Off-Peak - MN Docket E-002/M-19-33 - MN Docket E-002/M-21-222	1,108,391	10,549,275	142	10,083,601	1,574,065
36	Renewable*Connect Standard - MN Docket E-002/M-19-33 - MN Docket E-002/M-21-222	758,915	6,056,903	142	5,419,130	1,396,688
37	Sherco 3 Depreciation Deferral - MN Docket E-002/GR-15-826 - Amortized over 21 years (01/2014-12/2035)	5,031,295		407.3	503,130	4,528,165
38	South Dakota Electric Conservation and Energy Management Program Costs - SD Docket EL 25-020 - Generally amortized over 12 month period following the expenditure	100,197	823,539	142	799,301	124,435
39	South Dakota Infrastructure - SD Docket EL 25-033		2,378,218	407.3	2,234,464	143,754
40	South Dakota PI Payments	596,282	588,762			1,185,044
41	South Dakota Ratemaking Differences - SD Docket F-3382 - SD Docket F-3422 - Amortized over plant lives	2,883,250	429,000	405	534,000	2,778,250
42	South Dakota Transmission Cost Recovery Rider - SD Docket EL 25-031	896,610	1,744,218	407.4	1,016,626	1,624,202
43	Theoretical Depreciation Reserve Surplus - MN Docket E-002/GR-17-147 - Amortized over plant lives	210,824,223		407.3	8,842,237	201,981,986
44	Transmission Formula Rates	14,087,992	17,631,406	565	7,496,475	24,222,923
44	TOTAL	4,128,101,094	642,741,926		615,954,977	4,154,888,043

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: IncreaseDecreaseInOtherRegulatoryAssets

Accounts charged:		
517	\$	5,320,833
519		1,348,153
520		12,455,950
523		438,397
524		3,481,196
528		1,100,248
530		9,356,296
531		4,031,380
532		39,165,540
Total	\$	76,697,993

(b) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
517	\$	3,013,620
519		1,630,958
520		14,208,428
523		675,330
524		3,554,173
528		636,841
530		9,309,676
531		5,450,297
532		31,141,684
Total	\$	69,621,007

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

Accounts charged:		
421	\$	194,736
495		4,265,765
908		39,166,639
Total	\$	43,627,140

(d) Concept: OtherRegulatoryAssets

	Excess Nonplant ADIT - Regulatory Asset*	Gross-Up	Total
Electric	\$ 60,773,063	\$ 23,732,089	\$ 84,505,152
Gas	2,035,549	794,889	2,830,438
Total	\$ 62,808,612	\$ 24,526,978	\$ 87,335,590

*For purposes of calculating 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 12/31/2024	Amortization 2025	Excess Balance 12/31/2025
Federal Net Operating Loss	\$ 67,114,886	\$ (4,194,680)	\$ 62,920,206
Post Employment Benefits - Long Term Disability	1,023,165	(127,896)	895,269
Post Employment Benefits - Retiree Medical	3,281,549	(410,193)	2,871,356
Total Electric	\$ 71,419,600	\$ (4,732,769)	\$ 66,686,831

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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		Balance at End of Year (f)		
				Credits Account Charged (d)	Credits Amount (e)			
1	Conservation and Energy Management Program Costs Minnesota Electric (Docket E-002/M-25-50)	14,714,317	10,677,958	182.3	14,714,318	10,677,957		
2	Conservation and Energy Management Program Costs Minnesota Gas Incentive (Docket G-002/M-25-47)	5,279,618	3,078,042	182.3	5,279,617	3,078,043		
3	Federal and State Income Taxes Interest Receivable	134,931	393,190			528,121		
4	Federal and State Income Tax Receivable	3,422,146	389,395	236	111,501	3,700,040		
5	IPP Power Contract Billing Adjustments	532,056				532,056		
6	JOA & Rate Payer Share MTM	7,049,081	144,543			7,193,624		
7	Prepays - Facility Fees	1,101,104	1,422,194	431	489,895	2,033,403		
8	Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-21-630)		98,313	928	98,313			
9	Minnesota Electric Retail Rate Case Expenses (Docket E-002/GR-24-320) - Amortized through Dec. 2027	971,467	2,299,416	928	1,639,970	1,630,913		
10	Minnesota Gas Retail Rate Case Expenses (Docket G-002/GR-23-413) - Amortized through Dec. 2026	822,001	372,096	928	783,097	411,000		
11	Minnesota Gas Retail Rate Case Expenses (Docket G-002/GR-25-356)		545,550			545,550		
12	North Dakota Electric Retail Rate Case Expenses (Docket PU-24-376) - Amortized through Jan. 2028	488,680	411,100	928	428,695	471,085		
13	North Dakota Gas Retail Rate Case Expenses (Docket PU-23-367) - Amortized through Feb. 2027	546,832	676	928	272,500	275,008		
14	North Dakota Gas Retail Rate Case Expenses (Docket PU-26-052)		109,086			109,086		
15	South Dakota Electric Retail Rate Case Expenses (Docket EL 22-017) - Amortized through Dec. 2025	238,643		928	238,643			
16	South Dakota Electric Retail Rate Case Expenses (Docket EL 25-024)		433,308			433,308		
17	Recovery of Legislative Costs - Community Solar Garden (Docket E-002/CI-23-335)	961,000		928	423,326	537,674		
18	Loan Receivable - 3rd Party	1,068,370	903,270	143	1,898,192	73,448		
19	Debt Issuance Expense	211,774	8,022,873	181	7,722,732	511,915		
47	Miscellaneous Work in Progress							
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)							
49	TOTAL	37,542,020				32,742,231		

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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 at Beginning of Year (b)	Balance at End of Year (c)	
1	Electric			
2	Electric - Plant	288,374,097	319,921,030	
3	Electric - Non-Plant	1,117,406,725	1,005,143,962	
7	Other			
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,405,780,822	1,325,064,992	
9	Gas			
10		40,413,397	36,594,461	
15	Other			
16	TOTAL Gas (Enter Total of lines 10 thru 15)	40,413,397	36,594,461	
17.1	Other (Specify)	12,107,500	6,461,801	
17	Other (Specify)			
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,458,301,719	1,368,121,254	
Notes				

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: AccumulatedDeferredIncomeTaxes			
		Balance at Beginning of Year	Balance at End of Year
Electric Distribution Plant	\$	182,271,996	\$ 189,774,650
Electric General Plant		(4,907,489)	4,614,027
Electric Intangible Plant		2,675,781	2,272,053
Electric Nuclear Fuel		30,242,381	30,417,483
Electric Nuclear Production Plant		36,745,222	33,511,698
Electric Production Plant		56,632,519	57,674,987
Electric Transmission Plant		68,267,378	77,404,683
Electric Transmission-Production Plant		—	2,421,699
Common (Allocation to Electric)		2,484,989	4,132,209
Regulatory Differences - Effect of Rate Changes		(91,055,269)	(86,831,562)
Regulatory Differences - Investment Tax Credit Gross-Up		5,016,589	4,529,103
Total Electric Plant Related Only	\$	288,374,097	\$ 319,921,030
(b) Concept: AccumulatedDeferredIncomeTaxes			
		Balance at Beginning of Year	Balance at End of Year
Electric:			
Avoided Tax Interest		\$140,589,043	\$157,716,613
Bad Debts		11,121,114	8,988,294
Clean Energy Vehicle Credit		—	300,257
Customer Advances		5,771,405	5,408,721
Deferred Connection Fees		175,606,865	198,532,619
Deferred Rent		1,852,657	1,619,539
Deferred Revenue		56,564	—
Economic Development Securities - Write-Off		101,345	92,802
Employee Incentive Plans		2,491,890	4,659,827
Employee Retention		—	13,007
Employee Stock Ownership Program Dividends		7,638,739	7,778,711
End of Life Nuclear Fuel Amortization		38,172,211	27,869,088

Environmental Remediation	17,217,022	1,244,250
Excess Nonplant Accumulated Deferred Income Taxes	3,721,419	2,526,184
Fuel Tax Credit - Income Addback	5,994	5,411
Inventory Reserve	647,190	647,048
Mark to Market Adjustment	254,530	1,611,254
Medical Deductions - Self Insured	1,258,340	1,235,235
Minnesota Net Operating Loss	24,943	20,331
Monticello Extended Power Uprate Writedown	6,634,514	4,917,737
North Dakota Investment Tax Credit	60,665,008	60,456,352
North Dakota Investment Tax Credit - Valuation Allowance	(56,452,612)	(60,132,115)
North Dakota Investment Tax Credit - Federal Gross-Up	1,809,650	831,555
North Dakota Production Tax Credit - Levelization	8,322,539	10,639,929
Nuclear Production Tax Credit	172,681,247	81,679,384
Operating Lease Liabilities	105,140,838	31,686,882
Performance Recognition Awards	117,984	68,055
Post Employment Benefits - Retiree Medical	6,083,782	5,367,918
Post Employment Benefits - Long Term Disability	1,846,597	1,540,059
Post Employment Benefits - Voluntary Retirement Program	1,872,011	1,440,169
Public Utility Conservation Investment Programs	7,455,228	—
Rate Refund	9,285,202	9,824,293
Regulatory Asset/Liability - Minnesota Credit Card Fees	1,014,715	1,026,387
Regulatory Asset/Liability - Net Operating Loss Tracker	1,261,688	19,784
Regulatory Asset/Liability - Nuclear Production Tax Credit	56,395,797	37,565,504
Regulatory Asset/Liability - Renewable Energy Standard Rider	14,203,253	15,597,355
Regulatory Asset/Liability - Transmission Attach O	304,115	—
Regulatory Asset/Liability - Transmission Cost Recovery Rider	8,220,776	—
Regulatory Asset/Liability - Windsource	243,201	776,993
Regulatory Difference - Effect of Rate Changes	(91,055,269)	(86,831,562)
Regulatory Difference - Investment Tax Credit Gross-Up	5,016,589	4,529,103
Research and Experimentation Credit	36,126,740	39,478,123
Section 174 - Section 59(e) Adjustment	22,181,980	46,944,149
Severance Accrual	9,096	—
Solar Production Tax Credit	719,691	15,558,066
Solar Rewards Program	2,682,959	2,865,209
South Dakota Infrastructure Tracker	309,543	2,740,097
State Tax Deduction Cash vs. Accrual	665,589	634,212
Texas Gross Margin Tax	7,203	3,025
Vacation Accrual	6,627,299	6,985,492
Wind Production Tax Credit	608,827,937	668,583,646
Workers Compensation	24,661	—
Total Electric	\$ 1,405,780,822	\$ 1,325,064,992

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 of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.

Amortization of Excess ADIT (Electric only) included in 410.1 is \$2,695,598 for 2024 and \$2,701,131 for 2025.				
		2024 ARAM	2025 ARAM	
Unprotected ARAM:				
Decommissioning	\$	75	\$	(13,038)
Electric Distribution Plant		1,079,048		1,023,372
Electric General Plant		32,524		9,401
Electric Intangible Plant		109,480		109,634
Electric Production Plant		1,220,727		1,243,301
Electric Transmission Plant		243,770		319,657
Electric Transmission-Production Plant		3,560		3,510
Common (Allocation to Electric)		6,414		5,294
Total Electric	\$	2,695,598	\$	2,701,131
Common allocation for financial reporting may be different than for rate making.				
Common (Unallocated)	\$	7,098	\$	5,790
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)		12/31/2025		12/31/2025
Flow Through	\$	Excess	Gross up	Total Regulatory
Other Basis Differences (Unprotected)		474,628	185,344	659,972
		(62,920,761)	(24,570,773)	(87,491,534)
	\$	(62,446,133)	(24,385,429)	(86,831,562)
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)	\$ 401	\$ 157	558
		\$ 401	\$ 157	558
Common (allocated)				
	Other Basis Differences (Unprotected)	\$ 71,579	\$ 27,952	99,531
		\$ 71,579	\$ 27,952	99,531
Common (unallocated)				
	Other Basis Differences (Unprotected)	\$ (275,678)	\$ (107,653)	(383,331)
		\$ (275,678)	\$ (107,653)	(383,331)
(c) Concept: AccumulatedDeferredIncomeTaxes				
		Balance at Beginning of Year	Balance at End of Year	
Gas:				
Avoided Tax Interest	\$	5,109,508	\$	5,781,578
Bad Debts		1,103,907		1,819,491
Deferred Connection Fees		18,482,496		17,136,899
Deferred Rent		176,096		157,245
Economic Development Securities - Write-Off		10,059		18,786
Employee Incentive Plans		257,005		530,533
Employee Retention		—		1,481
Employee Stock Ownership Program Dividends		2,807,280		2,730,262
Environmental Remediation		75,889		113,996
Excess Nonplant Accumulated Deferred Income Taxes		258,653		196,662
Fuel Tax Credit - Income Addback		570		525
Inventory Reserve		61,515		62,824
Lower of Cost or Market on Gas Inventories		417,066		361,112
Medical Deduction - Self Insured		129,781		140,635
Minnesota Net Operating Loss		1,313		1,070
Operating Lease Liabilities		9,993,676		3,076,565
Performance Recognition Awards		12,168		7,748
Post Employment Benefits - Retiree Medical		627,461		611,150
Post Employment Benefits - Long Term Disability		190,452		175,340
Post Employment Benefits - Voluntary Retirement Program		193,073		163,967
Public Utility Conservation Investment Programs		—		289,735
Rate Refund		353,052		101,806
Regulatory Asset/Liability - Minnesota Credit Card Fees		897,086		766,549
Regulatory Asset/Liability - Miscellaneous		15,344		39,129
Regulatory Difference - Effect of Rate Changes		(5,512,324)		(5,167,852)
Regulatory Difference - Investment Tax Credit Gross-Up		217,559		177,421
Research and Experimentation Credit		1,713,046		1,919,845
Section 174 - Section 59(e) Adjustment		2,108,405		4,557,934
Severance Accrual		938		—
State Tax Deduction Cash vs. Accrual		26,263		26,710
Vacation Accrual		683,517		795,315
Workers Compensation		2,543		—
Total Gas	\$	40,413,397	\$	36,594,461
(d) Concept: AccumulatedDeferredIncomeTaxes				

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

(e) Concept: AccumulatedDeferredIncomeTaxes

	Balance at Beginning of Year		Balance at End of Year
Other:			
Avoided Tax Interest	\$	3,498,659	\$ 68
Deferred Compensation Plan Reserve		4,490,967	4,100,625
Deferred Connection Fees and CIAC		274,281	—
Minnesota Net Operating Loss		86	86
Nonqualified Pension Plans		85,373	66,872
Other Comprehensive Income		3,134,149	1,623,161
Partnership Passthrough		366,464	359,483
Performance Share Plan		257,536	311,520
Regulatory Difference - Effect of Rate Changes		(15)	(14)
Total Other	\$	12,107,500	\$ 6,461,801

(f) Concept: AccumulatedDeferredIncomeTaxes

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

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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.

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

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

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

6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	All NSP-Minnesota common stock is owned by parent, Xcel Energy Inc.	5,000,000	0.01		1,000,000	10,000				
7	Total	5,000,000			1,000,000	10,000				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 2026-04-09	Year/Period of Report End of: 2025/ Q4
Other Paid-in Capital				
1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related. Gain or 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. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.				
Line No.	Item (a)	Amount (b)		
1	Donations Received from Stockholders (Account 208)			
2	Beginning Balance Amount			
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders			
4	Ending Balance Amount			
5	Reduction in Par or Stated Value of Capital Stock (Account 209)			
6	Beginning Balance Amount			
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock			
8	Ending Balance Amount			
9	Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)			
10	Beginning Balance Amount			
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock			
12	Ending Balance Amount			
13	Miscellaneous Paid-In Capital (Account 211)			
14	Beginning Balance Amount	5,920,268,234		
15.1	Increases (Decreases) due to contribution of capital by parent	652,614,456		
16	Ending Balance Amount	6,572,882,690		
17	Other Paid in Capital			
18	Beginning Balance Amount			
19.1	Increases (Decreases) in Other Paid-In Capital			
20	Ending Balance Amount			
40	Total	6,572,882,690		

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22	TOTAL						

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026			Year/Period of Report End of: 2025/ Q4				
LONG-TERM DEBT (Account 221, 222, 223 and 224)													
1. Report by Balance Sheet Account the 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. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number. 3. 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, and in column (b) include the related account number. 4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number. 5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates. 6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge. 7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote. 8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies. 9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.													
Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	2.25% Apr 1, 2031 First Mortgage Bonds		425,000,000		5,122,108		1,776,500	03/30/2021	04/01/2031	03/30/2021	04/01/2031	425,000,000	9,562,500
3	3.20% Apr 1, 2052 First Mortgage Bonds		425,000,000		6,078,358		1,576,750	03/30/2021	04/01/2052	03/30/2021	04/01/2052	361,104,000	13,600,000
4	4.85% Aug 15, 2040 First Mortgage Bonds		250,000,000		3,019,146		707,500	08/11/2010	08/15/2040	08/11/2010	08/15/2040	250,000,000	12,125,000
5	3.40% Aug 15, 2042 First Mortgage Bonds		500,000,000		6,272,718		3,820,000	08/13/2012	08/15/2042	08/13/2012	08/15/2042	500,000,000	18,496,479
6	4.00% Aug 15, 2045 First Mortgage Bonds		300,000,000		3,897,956		4,899,000	08/11/2015	08/15/2045	08/11/2015	08/15/2045	152,317,000	12,000,000
7	^(a) 7.125% Jul 1, 2025 First Mortgage Bonds		250,000,000		1,898,333		2,330,000	07/07/1995	07/01/2025	07/07/1995	07/01/2025		8,906,250
8	5.25% Jul 15, 2035 First Mortgage Bonds		250,000,000		3,032,114		485,000	07/21/2005	07/15/2035	07/21/2005	07/15/2035	250,000,000	13,125,000
9	6.20% Jul 1, 2037 First Mortgage Bonds		350,000,000		4,336,843		1,988,000	06/26/2007	07/01/2037	06/26/2007	07/01/2037	350,000,000	21,700,000
10	6.25% Jun 1, 2036 First Mortgage Bonds		400,000,000		4,877,065		1,404,000	05/25/2006	06/01/2036	05/25/2006	06/01/2036	400,000,000	24,455,460 ^(d)
11	2.60% Jun 1, 2051 First Mortgage Bonds		700,000,000		9,787,023		13,174,000	06/15/2020	06/01/2051	06/15/2020	06/01/2051	443,473,000	18,200,000
12	4.50% Jun 1, 2052 First Mortgage Bonds		500,000,000		7,596,315		3,605,000	05/09/2022	06/01/2052	05/09/2022	06/01/2052	500,000,000	22,500,000
13	6.50% Mar 1, 2028 First Mortgage Bonds		150,000,000		1,474,885		1,761,001	03/17/1998	03/01/2028	03/17/1998	03/01/2028	150,000,000	9,750,000
14	2.90% Mar 1, 2050 First Mortgage Bonds		600,000,000		8,727,023		11,574,000	09/10/2019	03/01/2050	09/10/2019	03/01/2050	479,476,000	17,400,000
15	5.40% Mar 15, 2054 First Mortgage Bonds		700,000,000		10,217,694		2,709,000	02/29/2024	03/15/2054	02/29/2024	03/15/2054	700,000,000	37,517,094 ^(e)
16	^(b) 5.05% May 15, 2035 First Mortgage Bonds		600,000,000		7,301,557		432,000	05/05/2025	05/15/2035	05/05/2025	05/15/2035	600,000,000	19,745,959 ^(f)
17	4.125% May 15, 2044 First Mortgage Bonds		300,000,000		3,821,358		873,000	05/13/2014	05/15/2044	05/13/2014	05/15/2044	119,922,000	12,375,000
18	3.60% May 15, 2046 First Mortgage Bonds		350,000,000		5,404,423		2,093,000	05/31/2016	05/15/2046	05/31/2016	05/15/2046	165,607,000	12,600,000
19	5.10% May 15, 2053 First Mortgage Bonds		800,000,000		11,417,227		5,968,000	05/08/2023	05/15/2053	05/08/2023	05/15/2053	800,000,000	40,640,527 ^(g)
20	5.65% May 15, 2055 First Mortgage Bonds		500,000,000		7,206,104		2,730,000	05/05/2025	05/15/2055	05/05/2025	05/15/2055	500,000,000	18,458,571 ^{(h) (i)}
21	5.35% Nov 1, 2039 First Mortgage Bonds		300,000,000		4,153,918		570,000	11/17/2009	11/01/2039	11/17/2009	11/01/2039	300,000,000	16,156,992 ⁽ⁱ⁾
22	3.60% Sep 15, 2047 First Mortgage Bonds		600,000,000		8,795,587		5,982,000	09/13/2017	09/15/2047	09/13/2017	09/15/2047	600,000,000	21,600,000
23	Subtotal		9,250,000,000		124,437,755		70,457,751					8,046,899,000	380,914,832
24	Reacquired Bonds (Account 222)												
25													

26													
27													
28	Subtotal												
29	Advances from Associated Companies (Account 223)												
30	3.20% Apr 1, 2052 First Mortgage Bonds \$425MM [Repurchased by XLE in 2025]		63,896,000		784,213		203,276	03/30/2021	04/01/2052	03/30/2021	04/01/2052	63,896,000	(777,817)
31	4.00% Aug 15, 2045 First Mortgage Bonds \$300MM [Repurchased by XLE in 2025]		147,686,000		1,255,184		1,576,573	08/11/2015	08/15/2045	08/11/2015	08/15/2045	147,683,000	(98,455)
32	2.60% Jun 1, 2051 First Mortgage Bonds \$700MM [Repurchased by XLE in 2025]		256,527,000		3,037,671		4,086,937	06/15/2020	06/01/2051	06/15/2020	06/01/2051	256,527,000	(5,405,472)
33	2.90% Mar 1, 2050 First Mortgage Bonds \$600MM [Repurchased by XLE in 2025]		120,524,000		1,413,496		1,873,368	09/10/2019	03/01/2050	09/10/2019	03/01/2050	120,524,000	(1,508,764)
34	4.125% May 15, 2044 First Mortgage Bonds \$300MM [Repurchased by XLE in 2025]		180,078,000		1,405,183		320,788	05/13/2014	05/15/2044	05/13/2014	05/15/2044	180,078,000	(123,804)
35	3.60% May 15, 2046 First Mortgage Bonds \$350MM [Repurchased by XLE in 2025]		184,393,000		1,937,705		749,889	05/31/2016	05/15/2046	05/31/2016	05/15/2046	184,393,000	(139,483)
36	Subtotal		953,104,000		9,833,452		8,810,831					953,101,000	(8,053,795)
37	Other Long Term Debt (Account 224)												
38	Right of Way Debt											1,740,683	158,596
39	Interest on Debt to Associated Companies												14,701,620
40	Subtotal											1,740,683	14,860,216
33	TOTAL		10,203,104,000									9,001,740,683	387,721,253

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FOOTNOTE DATA			
(a) Concept: ClassAndSeriesOfObligationCouponRateDescription			
NSPMN 7.125% \$250MM matured on 7/1/2025.			
(b) Concept: ClassAndSeriesOfObligationCouponRateDescription			
Minnesota Public Utilities Commission Case no. E-002/S-24-368. Order dated March 21, 2025.			
In May of 2025, NSPM issued \$600,000,000 of 5.05 percent First Mortgage Bonds, due May 15, 2035. The planned use of proceeds was to add the aggregate net proceeds from the sale of the first mortgage bonds to its general corporate funds and apply a portion of such net proceeds to fund the repayment of its \$250 million of 7.125% First Mortgage Bonds, Series due July 1, 2025. The balance of the net proceeds will be used for general corporate purposes.			
(c) Concept: InterestExpenseBonds			
Interest at stated rate	\$		17,000,000
Interest at swap loss			1,496,479
	\$		18,496,479
(d) Concept: InterestExpenseBonds			
Interest at stated rate	\$		25,000,000
Interest at swap gain			(544,540)
	\$		24,455,460
(e) Concept: InterestExpenseBonds			
Interest at stated rate	\$		37,800,000
Interest at swap gain			(282,906)
	\$		37,517,094
(f) Concept: InterestExpenseBonds			
Interest at stated rate	\$		19,863,333
Interest at swap gain			(117,374)
	\$		19,745,959
(g) Concept: InterestExpenseBonds			
Interest at stated rate	\$		40,800,000
Interest at swap gain			(159,473)
	\$		40,640,527
(h) Concept: InterestExpenseBonds			
Interest at stated rate	\$		18,519,444
Interest at swap gain			(60,873)
	\$		18,458,571
(i) Concept: InterestExpenseBonds			
Minnesota Public Utilities Commission Case no. E-002/S-24-368. Order dated March 21, 2025.			
In May of 2025, NSPM issued \$500,000,000 of 5.65 percent First Mortgage Bonds, due May 15, 2055. The planned use of proceeds was to add the aggregate net proceeds from the sale of the first mortgage bonds to its general corporate funds and apply a portion of such net proceeds to fund the repayment of its \$250 million of 7.125% First Mortgage Bonds, Series due July 1, 2025. The balance of the net proceeds will be used for general corporate purposes.			
(j) Concept: InterestExpenseBonds			
Interest at stated rate	\$		16,050,000
Interest at swap loss			106,992
	\$		16,156,992
(k) Concept: OtherLongTermDebt			
Right of Way Debt	Balance Dec. 31, 2024 \$2,032,176	Additions \$—	Reductions \$(291,493) Balance Dec. 31, 2025 \$1,740,683
(l) Concept: InterestExpenseOtherLongTermDebt			

Xcel Energy Service Inc	\$	4,589,337
Interest Exp LTD Interco to XLE		8,053,795
Money Pool		<u>2,058,488</u>
	\$	<u>14,701,620</u>

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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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members. 3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.				
Line No.	Particulars (Details) (a)		Amount (b)	
1	Net Income for the Year (Page 117)		903,512,230	
2	Reconciling Items for the Year			
3				
4	Taxable Income Not Reported on Books			
5			148,142,648	
9	Deductions Recorded on Books Not Deducted for Return			
10			1,969,245,824	
14	Income Recorded on Books Not Included in Return			
15			(365,701,438)	
19	Deductions on Return Not Charged Against Book Income			
20			(2,326,709,663)	
21	Equity in Earnings of Subsidiary Companies		(983,306)	
22	Total Income Tax Expense		(193,597,355)	
27	Federal Tax Net Income		133,908,940	
28	Show Computation of Tax:			
29	Federal Income Tax at 21 percent		28,120,877	
30	Other		8,909,701	
31	Total Federal Income Tax Payable		37,030,578	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT REPORTED ON BOOKS:		
Contributions in Aid of Construction	\$	98,860,142
Rate Surcharge		49,282,506
	\$	148,142,648

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

DEDUCTIONS RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:		
Avoided Cost Interest	\$	79,357,516
Book Amortization - Acquisition Adjustments		14,976
Book Amortization - Computer Software		127,567,934
Book Amortization - Other		40,216,298
Book Amortization - Regulatory Asset		4,065,094
Book Depreciation		974,671,343
Book Income - Wisconsin/South Dakota Allowance for Funds During Construction		20,000
Book Unamortized Cost of Reacquired Debt		779,086
Clearing Account Book Expense		31,638,379
Deferred Fuel Costs		31,235,658
Employee Incentive Plans		8,677,464
Employee Retention		604,818
Employee Stock Ownership Plan Dividends		1,546,000
Lobbying Expenses		1,935,000
Mark to Market Adjustment		4,829,530
Meals & Entertainment		2,423,000
Medical Deductions - Self Insured		1,426,486
Nuclear Decommissioning		2,769,551
Nuclear Fuel Expense		103,662,304
Operating Lease Assets		286,851,070
Penalties		66,840
Pension and Benefit Capitalized		3,785,053
Performance Share Plan		190,719
Rate Case/Restructuring Expense		63,033,573
Regulatory Asset - Gas Safety Deferrals		7,537,829
Regulatory Asset/Liability - Cancellation		4,412,637
Regulatory Asset/Liability - Decoupling		7,351,979
Regulatory Asset/Liability - Miscellaneous		258,491
Regulatory Asset/Liability - Renewable Energy Standard Rider		4,880,959
Regulatory Asset/Liability - Windsource		1,899,303
Regulatory Reserve - Environmental		56,069,342
Section 174 - Section 59(e) Adjustment		96,753,119
Solar Rewards Program		633,247
South Dakota Infrastructure Tracker		8,652,895
State Tax Deduction		5,856,195
Suite and Entertainment Tickets		508,000
Vacation Accrual		3,064,136
	\$	1,969,245,824

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:		
Allowance for Funds During Construction - Equity (Non-Conservation Improvement Program)	\$	(69,277,868)
Deferred Revenue		(201,744)
Deferred Revenue - Investment Tax Credit Grant		(68,945)
Insurance Fund Income (Cash Value)		(3,851,874)
Interest Income/Expense on Disputed Tax		(5,441,866)
Operating Lease Liabilities		(286,859,141)
	\$	(365,701,438)

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:		
Allowance for Funds During Construction - Debt (Non-Conservation Improvement Program)	\$	(37,057,359)
Bad Debts		(5,118,067)
Book Amortization - Monticello Extended Power Uprate Writedown Amortization		(6,135,751)
Deferred Compensation Plan Reserve		(1,416,220)
Deferred Rent		(909,084)
Environmental Remediation		(56,841,356)
External Qualified Nuclear Decommissioning Fund		(11,730,141)
Gain/(Loss) on Dispositions (Tax)		(21,891,965)
Nonqualified Pension Plan		(66,379)
Pension Expense		(23,420,284)
Performance Recognition Awards		(194,288)
Post Employment Benefits - Long Term Disability		(1,157,256)
Post Employment Benefits - Retiree Medical		(2,646,417)
Post Employment Benefits - Voluntary Retirement Program		(1,653,436)
Prepaid Advertising		(208,774)
Prepaid Insurance		(4,555,535)
Public Utility Conservation Investments Programs Adjustment		(23,789,420)
Rate Refund		(11,428,102)
Regulatory Asset - Nuclear Refueling Outage Costs		(7,076,986)
Regulatory Asset - Property Tax		(10,311,351)
Regulatory Asset/Liability - Minnesota Credit Card Fees		(434,446)
Regulatory Asset/Liability - Net Operating Loss Tracker		(4,429,554)
Regulatory Asset/Liability - Nuclear Production Tax Credit		(54,984,408)
Regulatory Asset/Liability - Transmission Attach O		(14,343,744)
Regulatory Asset/Liability - Transmission Cost Recovery Rider		(35,567,741)
Repair Expenditures		(127,649,898)
Section 174		(167,305,520)
Severance Accrual		(35,790)
Tax Amortization - Monticello Rerate		(6,160,471)
Tax Amortization - Computer Software		(128,583,961)
Tax Depreciation		(1,423,187,910)
Tax Expense - Spent Fuel Isolation Devices		(2,072,503)
Tax Removal Cost Over Book		(134,248,517)
Workers Compensation		(97,029)
	\$	(2,326,709,663)

[\(e\)](#) Concept: ComputationOfTax

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 2025. The other members of the affiliated group and the federal income tax provision of each are:	
Xcel Energy Inc.	(55,733,912)
NSP Nuclear Corporation	(82)
United Power and Land Company	291,089
Northern States Power Company (Wisconsin) and Subsidiaries	19,686,955
Public Service Company of Colorado and Subsidiaries	(55,826,739)
Southwestern Public Service Company	30,339,717
Nicollet Holdings Company, LLC and Subsidiaries	1,839,141
Nicollet Project Holdings LLC and Subsidiaries	494,364
Xcel Energy Communications Group Inc. and Subsidiaries	(104,289)
Xcel Energy Markets Holdings Inc. and Subsidiaries	242,543
Xcel Energy International Inc.	(131)
Xcel Energy Nuclear Services, Inc. and Subsidiaries	10,037
Xcel Energy Retail Holdings Inc. and Subsidiaries	3,496
Xcel Energy Transmission Holding Company, LLC and Subsidiaries	(75,409)
Xcel Energy Ventures Inc. and Subsidiaries	158,266
Xcel Energy Venture Holdings, Inc. and Subsidiaries	860,821
Xcel Energy Wholesale Group Inc. and Subsidiaries	(18,170)
Xcel Energy WYCO Inc.	4,667,394
WestGas Interstate, Inc.	428
Xcel Energy Services Inc.	8,166,689
The consolidated federal income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.	

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission				Date of Report: 04/09/2026			Year/Period of Report End of: 2025/ Q4				
TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR															
1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts. 2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes. 3. Include in column (g) 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. 5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d). 6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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.															
Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Income	Federal Tax					37,748,344	28,638,569	(9,109,775)			54,107,972			(16,359,628)
2	Income Tax Adjustment	Federal Tax					(717,767)		717,767			(717,572)			(195)
3	FICA	Federal Tax		2024	1,603,569			1,603,569							
4	FICA	Federal Tax		2025			44,659,929	42,339,198			2,320,731		31,132,775		13,527,154
5	Unemployment	Federal Tax		2024	1,556			1,556							
6	Unemployment	Federal Tax		2025			187,393	181,837			5,556		140,628		46,765
7	Subtotal Federal Tax				1,605,125		81,877,899	72,764,729	(8,392,008)	2,326,287		84,663,803			(2,785,904)
8	Income	State Tax	Minnesota				490,180	(5,379,059)	(5,869,239)			8,438,718			(7,948,538)
9	Income Tax Adjustment	State Tax	Minnesota				(147,282)		147,282			(149,413)			2,131
10	Unemployment	State Tax	Minnesota	2024	113,293			113,293							
11	Unemployment	State Tax	Minnesota	2025			3,600,196	3,498,269			101,927		2,126,829		1,473,367
12	Property Tax	State Tax	Minnesota	2023			700	700				625			75
13	Property Tax	State Tax	Minnesota	2024	199,128,000		6,847,575	205,967,725			7,850		6,105,874		741,701
14	Property Tax	State Tax	Minnesota	2025			220,884,000				220,884,000		194,784,000		26,100,000
15	Income	State Tax	North Dakota				(227,428)	(415,726)	(188,298)			(42,335)			(185,093)
16	Unemployment	State Tax	North Dakota	2024	44			44							
17	Unemployment	State Tax	North Dakota	2025			9,149	8,964			185		4,528		4,621
18	Property Tax	State Tax	North Dakota	2024	8,568,000		(27,215)	8,540,785				(35,678)			8,463
19	Property Tax	State Tax	North Dakota	2025			8,429,069	35,069			8,394,000		6,611,069		1,818,000
20	Unemployment	State Tax	South Dakota	2024	(818)			(818)							
21	Unemployment	State Tax	South Dakota	2025			7,346	9,114			(1,768)		3,635		3,711
22	Property Tax	State Tax	South Dakota	2024	6,462,000		(292,587)	6,169,413				(292,587)			
23	Property Tax	State Tax	South Dakota	2025			6,660,000				6,660,000		6,660,000		
24	Personal Property	State Tax	Iowa	2024	396,000		6,330	402,330				6,330			
25	Personal Property	State Tax	Iowa	2025			636,000				636,000		636,000		

26	Personal Property	State Tax	Kansas	2024			(15,551)	(15,551)							(15,551)
27	Personal Property	State Tax	Kansas	2025			1,224,216	1,224,216							1,224,216
28	Income	State Tax	Wisconsin		36,000		(48,959)	(73,383)	(44,424)	16,000		(45,775)			(3,184)
29	Unemployment	State Tax	Wisconsin	2025	(317)		5,997	5,680				2,968			3,029
30	Income	State Tax	Texas		72,630		106,826	15,182	(56,752)	107,522		103,586			3,240
31	Unemployment	State Tax	Georgia	2025	21		(4)			17		(1)			(3)
32	Unemployment	State Tax	Colorado	2025	20		(20)					(10)			(10)
33	Subtotal State Tax				214,774,873		248,148,538	220,106,247	(6,011,431)	236,805,733		224,918,363			23,230,175
34	Denver Occ'l Privilege	Other Taxes		2025								11,306			(11,306)
35	Miscellaneous Income	Other Taxes					(1,209)	(3,209)	(2,000)						(1,209)
36	(a) Property Tax on Rail Car	Other Taxes		2024	2,400		(1,283)	1,117							(1,283)
37	(a) Property Tax on Rail Car	Other Taxes		2025			1,200			1,200					(a) 1,200
38	Other	Other Taxes		2025			99,199	99,199				91,995			(a) 7,204
39	Use	Other Taxes		2025	4,164,560		28,109,068	31,159,218		1,114,410					28,109,068 (a)
40	Subtotal Other Tax				4,166,960		28,206,975	31,256,325	(2,000)	1,115,610		103,301			28,103,674
40	TOTAL				220,546,958		358,233,412	324,127,301	(14,405,439)	240,247,630		309,685,467			48,547,945

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged			
Property tax on railroad cars used to transport coal from mines to electric generating plants.			
(b) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged			
Property tax on railroad cars used to transport coal from mines to electric generating plants.			
(c) Concept: TaxAdjustments			
Annual allocation of federal detriment on unitary benefit/detriment for state income taxes accrued as additional paid in capital (211)		\$	(10,138,773)
Federal income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)			(111,501)
Federal income tax benefit (accrual and cash) in other accounts receivable (143)			1,140,499
Total		\$	<u><u>(9,109,775)</u></u>
(d) Concept: TaxAdjustments			
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)			717,767
Total		\$	<u><u>717,767</u></u>
(e) Concept: TaxAdjustments			
Annual allocation of unitary benefit/detriment for Minnesota income taxes accrued as additional paid in capital (211)		\$	47,248,000
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)			371,758
State income tax benefit (accrual and cash) in other accounts receivable (143)			(53,488,997)
Total		\$	<u><u>(5,869,239)</u></u>
(f) Concept: TaxAdjustments			
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (242)		\$	(1,407,649)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)			1,554,931
Total		\$	<u><u>147,282</u></u>
(g) Concept: TaxAdjustments			
Annual allocation of unitary benefit/detriment for North Dakota income taxes accrued as additional paid in capital (211)		\$	1,124,485
State income tax expense (409.1 and 409.2) accrued for long term income tax receivable (186)			17,637
State income tax benefit (accrual and cash) in other accounts receivable (143)			(1,330,420)
Total		\$	<u><u>(188,298)</u></u>
(h) Concept: TaxAdjustments			
Annual allocation of unitary benefit/detriment for Wisconsin income taxes accrued as additional paid in capital (211)		\$	<u><u>(44,424)</u></u>
(i) Concept: TaxAdjustments			
Annual allocation of unitary benefit/detriment for Texas income tax accrued as additional paid in capital (211)		\$	(48,189)
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (253)			(8,563)
Total		\$	<u><u>(56,752)</u></u>
(j) Concept: TaxAdjustments			
State income tax benefit (accrual and cash) in other accounts receivable (143)		\$	<u><u>2,000</u></u>
(k) Concept: TaxesIncurredOther			
Gas (Account No. 409.1)		\$	(18,997,842)
Other income and deductions (Account No. 409.2)			2,638,215
Rounding			(1)
Total		\$	<u><u>(16,359,628)</u></u>
(l) Concept: TaxesIncurredOther			

Gas (Account No. 409.1)	\$	(195)
Total	\$	(195)
(m) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	3,702,461
Other income and deductions (Account No. 408.2)		50,818
Other		9,773,875
Total	\$	13,527,154
(n) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	16,778
Other income and deductions (Account No. 408.2)		253
Other		29,734
Total	\$	46,765
(o) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	(9,147,821)
Other income and deductions (Account No. 409.2)		1,199,283
Total	\$	(7,948,538)
(p) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	2,131
Total	\$	2,131
(q) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	250,856
Other income and deductions (Account No. 408.2)		2,575
Other		1,219,936
Total	\$	1,473,367
(r) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	75
Total	\$	75
(s) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	739,372
Other income and deductions (Account No. 408.2)		2,329
Total	\$	741,701
(t) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	25,980,000
Other income and deductions (Account No. 408.2)		120,000
Total	\$	26,100,000
(u) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	(200,570)
Other income and deductions (Account No. 409.2)		15,477
Total	\$	(185,093)
(v) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	528
Other income and deductions (Account No. 408.2)		3
Other		4,090
Total	\$	4,621
(w) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	8,463
(x) Concept: TaxesIncurredOther		

Gas (Account No. 408.1)	\$	1,818,000
(y) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	424
Other income and deductions (Account No. 408.2)		2
Other		3,285
Total	\$	3,711
(z) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	(15,551)
(aa) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,224,216
(ab) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	2
Other income and deductions (Account No. 409.2)		(3,186)
Total	\$	(3,184)
(ac) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	346
Other income and deductions (Account No. 408.2)		2
Other		2,681
Total	\$	3,029
(ad) Concept: TaxesIncurredOther		
Gas (Account No. 409.1)	\$	3,240
Total	\$	3,240
(ae) Concept: TaxesIncurredOther		
Other	\$	(3)
Total	\$	(3)
(af) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	(1)
Other		(9)
Total	\$	(10)
(ag) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	1,406
Other income and deductions (Account No. 408.2)		45
Other		(12,757)
Total	\$	(11,306)
(ah) Concept: TaxesIncurredOther		
Other income and deductions (Account No. 409.2)	\$	(1,209)
(ai) Concept: TaxesIncurredOther		
Other	\$	(1,283)
(aj) Concept: TaxesIncurredOther		
Other	\$	1,200
(ak) Concept: TaxesIncurredOther		
Gas (Account No. 408.1)	\$	7,202
Rounding		2
Total	\$	7,204

(a) Concept: TaxesIncurredOther		
Other income and deductions (Account No. 408.2)	\$	498
Other		28,108,570
Total	\$	28,109,068

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4			
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)										
Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.										
Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	24,070			411.4	4,718		19,352	58 Years	
4	7%									
5	10%	11,213,089			411.4	1,101,282		10,111,807	57 Years	
6	30%	895,270			411.4	97,312		797,958	22 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	12,132,429				1,203,312		10,929,117 ^(a)		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	Gas Utility									
12	4%	1,173			411.4	63		1,110	70 Years	
13	10%	552,213			411.4	103,412		448,801	51 Years	
14	TOTAL Gas Utility	553,386				103,475		449,911		
15	Common Utility									
16	4%	178			411.4	176		2	50 Years	
17	10%	53,713			411.4	5,873		47,840	50 Years	
18	TOTAL Common Utility	53,891				6,049		^(b) 47,842		
47	OTHER TOTAL									
48	GRAND TOTAL	12,739,706				1,312,836		11,426,870		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4												
FOOTNOTE DATA															
(a) Concept: AccumulatedDeferredInvestmentTaxCredits															
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.															
(b) Concept: AccumulatedDeferredInvestmentTaxCredits															
<table><tr><td>(a) Common Allocation</td><td></td><td></td></tr><tr><td>Electric - 92.96%</td><td>\$</td><td>44,473</td></tr><tr><td>Gas - 7.04%</td><td></td><td>3,369</td></tr><tr><td></td><td>\$</td><td>47,842</td></tr></table>				(a) Common Allocation			Electric - 92.96%	\$	44,473	Gas - 7.04%		3,369		\$	47,842
(a) Common Allocation															
Electric - 92.96%	\$	44,473													
Gas - 7.04%		3,369													
	\$	47,842													

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
OTHER DEFERRED CREDITS (Account 253)								
1. Report below the particulars (details) called for concerning other deferred credits. 2. For any deferred credit being amortized, show the period of amortization. 3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.								
Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)		
			Contra Account (c)	Amount (d)				
1	CapX2020 Promissory Notes		232	57,061		(57,061)		
2	Customer Prepayments	1,871,500	107	200,000	1,256,200	2,927,700		
3	Deferred Compensation - Employees	12,793,097	131	4,282,630	2,839,420	11,349,887		
4	Deferred Compensation - Employees (Wealth Op)	3,224,618	232	431,565	458,555	3,251,608		
5	401 Nicollet Lease Credit	4,800,014	101	757,896		4,042,118		
6	Deferred Revenue	201,744	^(b) Various	735,642	533,898			
7	Deferred Revenue-ITC Grant - Amortized over plant lives	694,542	405	68,945		625,597		
8	Environmental & Regulatory Reserves	1,359,363	242	1,285,551	1,701,271	1,775,083		
9	Executive PSP - Long Term	599,978	232	355,333	719,564	964,209		
10	Long-Term Income Tax & Interest Payable	19,978,365	^(g) Various	2,543,710	8,563	17,443,218		
11	Unfunded Nonqualified Pension Benefit Costs	1,699,999	232	355,379	412,379	1,756,999		
12	Nuclear Waste Strategy Coalition	63,953	253	21,980	20,400	62,373		
13	Postemployment Benefit-Injury Compensation	7,265,441	^(g) Various	1,959,021	801,766	6,108,186		
14	Pre-Funded AFUDC: Metro Emissions Reduction Rider	41,246,342	405	2,226,731		39,019,611		
15	Pre-Funded AFUDC: Mercury Emission Reduction Rider	122,778	405	24,816		97,962		
16	Pre-Funded AFUDC: Minnesota Transmission Cost Recovery Rider	37,310,408	^(g) Various	2,088,882	2,248,468	37,469,994		
17	Pre-Funded AFUDC: FERC Transmission	35,072,315	405	^(g) 684,493	^(d) 150,026	34,537,848		
18	Pre-Funded AFUDC: Renewable Energy Standards Rider	126,650,742	^(f) Various	8,142,258	37,230,781	155,739,265		
19	Pre-Funded AFUDC: South Dakota Transmission Cost Recovery Rider	2,438,832	^(g) Various	39,235	384,284	2,783,881		
20	Pre-Funded AFUDC: North Dakota Transmission Cost Recovery Rider	2,536,483	^(b) Various	48,290	592,022	3,080,215		
21	Renewable Development Fund Obligations	38,041,902	232	33,048,208	34,250,000	39,243,694		
22	Shared Network Upgrade	822,624				822,624		
23	^(g) ***Footnote from page 106b							
47	TOTAL	338,795,040		59,357,626	83,607,597	363,045,011		

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: DescriptionOfOtherDeferredCredits			
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.			
(b) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
456	\$		479,167
456.1			256,475
Total	\$		735,642
(c) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
232	\$		389,067
409.1			2,272,698
419			10,648
431			(128,703)
Total	\$		2,543,710
(d) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
232	\$		915,394
234			1,043,627
Total	\$		1,959,021
(e) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
405	\$		1,624,521
432			151,694
419.1			312,667
Total	\$		2,088,882
(f) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
405	\$		4,020,104
432			1,378,780
419.1			2,743,374
Total	\$		8,142,258
(g) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
432	\$		12,803
419.1			26,432
Total	\$		39,235
(h) Concept: DecreaseInOtherDeferredCreditsContraAccount			
Accounts charged:			
432	\$		15,793
419.1			32,497
Total	\$		48,290
(i) Concept: DecreaseInOtherDeferredCredits			
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 \$996,157.			
(j) Concept: IncreaseInOtherDeferredCredits			
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 \$218,813.			

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission				Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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. 3. Use footnotes as required.											
Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	17,911,074	(1,685,441)								16,225,633 (a)
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	17,911,074	(1,685,441)								16,225,633 (a)
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	17,911,074	(1,685,441)								16,225,633
18	Classification of TOTAL										
19	Federal Income Tax	13,953,095	(1,311,800)								12,641,295
20	State Income Tax	3,957,979	(373,641)								3,584,338
21	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty			
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 taxes balances of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.			
(b) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty			
All amounts in columns b - k are related to Electric Steam Production Plant			

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission			Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4			
ACCUMULATED DEFERRED 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. 3. Use footnotes as required.											
Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	2,905,773,694	139,567,539				182.3, 254 & 282	127,401,755	182.3, 254 & 282	277,734,900	3,195,674,378 ^(a)
3	Gas	184,012,552	65,639,850				182.3, 254 & 282	101,159	182.3, 254 & 282	4,001,143	253,552,386
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	3,089,786,246	205,207,389					127,502,914		281,736,043	3,449,226,764
6	Other (Non-Operating)	6,547,135			(6,106,332)		182.3, 254 & 282				440,803
9	TOTAL Account 282 (Total of Lines 5 thru 8)	3,096,333,381	205,207,389		(6,106,332)			127,502,914		281,736,043	3,449,667,567
10	Classification of TOTAL										
11	Federal Income Tax	2,097,158,506	127,693,267		(4,166,142)		182.3, 254 & 282	81,497,405	182.3, 254 & 282	191,538,787	2,330,727,013
12	State Income Tax	999,174,875	77,514,122		(1,940,190)		182.3, 254 & 282	46,005,509	182.3, 254 & 282	90,197,256	1,118,940,554
13	Local Income Tax										

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

	Dec. 31, 2024	410.1 & Adjustments	Dec. 31, 2025
Decommissioning Nonqualified	\$ —	\$ —	\$ —
Electric Distribution Plant	842,168,431	69,047,383	911,215,814
Electric General Plant	96,326,818	(26,764,897)	69,561,921
Electric Intangible Plant	13,251,957	(2,079,813)	11,172,144
Electric Nuclear Fuel	24,623,047	4,372,061	28,995,108
Electric Nuclear Production Plant	468,536,873	(2,649,598)	465,887,275
Electric Production Plant	1,173,550,456	61,756,927	1,235,307,383
Electric Transmission Plant	978,186,928	(2,291,949)	975,894,979
Electric Transmission-Production Plant	—	28,085,225	28,085,225
Common (Allocation to Electric)	41,238,016	10,092,202	51,330,218
Regulatory Differences - Prior Flow Thru / Rate Change	(1,111,697,028)	53,639,923	(1,058,057,105)
Regulatory Differences - AFUDC Equity	—	—	—
Decommissioning Qualified	379,588,196	96,693,220	476,281,416
Total Electric Plant Related Only	\$ 2,905,773,694	\$ 289,900,684	\$ 3,195,674,378

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 of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.

Amortization of Excess ADIT (Electric only) included in 410.1 is \$35,299,297 for 2024 and \$34,559,723 for 2025.

	2024 ARAM	2025 ARAM
Protected ARAM:		
Decommissioning	\$ —	\$ —
Electric Distribution Plant	4,282,485	5,563,350
Electric General Plant	2,441,013	1,666,971
Electric Intangible Plant	59,554	58,929
Electric Nuclear Fuel	(6,563)	(17,043)
Electric Production Plant	15,052,143	14,907,133
Electric Transmission Plant	3,564,893	2,798,096
Electric Transmission-Production Plant	81,380	87,963
Common (Allocation to Electric)	1,252,524	1,243,358
Total Protected ARAM	26,727,429	26,308,757
Unprotected ARAM:		
Decommissioning	—	—
Electric Distribution Plant	2,142,028	2,122,770
Electric General Plant	40,252	14,912
Electric Intangible Plant	113,808	112,023
Electric Nuclear Fuel	(2,188)	(5,318)
Electric Production Plant	5,232,616	4,737,144
Electric Transmission Plant	887,487	1,132,969
Electric Transmission-Production Plant	8,208	9,399
Common (Allocation to Electric)	149,717	127,388
Total Unprotected ARAM	8,571,928	8,251,287
Non Utility	(60)	(321)
Total Electric	\$ 35,299,297	\$ 34,559,723

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

Common (Unallocated)	\$	1,551,810	\$	1,498,940
For 2025, the flowback of permanent items included in 410.1 are included in 283.				
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)		12/31/2025 Excess		12/31/2025 Gross up
Flow Through	\$	1,280,113	\$	499,887
Method Life (Protected)		(629,079,833)		(245,657,825)
Other Basis Differences (Unprotected)		(133,116,859)		(51,982,588)
	\$	(760,916,579)	\$	(297,140,526)
Includes Non-Utility and Common Allocated. The common allocation for the financial reporting is different from the allocation used in rate making.				
Non-utility				12/31/2025 Total Regulatory
Flow Through	\$	99,995	\$	139,043
Method Life (Protected)		707		276
Other Basis Differences (Unprotected)		—		—
	\$	100,702	\$	140,026
Common (allocated)				
Flow Through	\$	19,810	\$	27,546
Method Life (Protected)		(6,132,522)		(2,394,771)
Other Basis Differences (Unprotected)		(132,145)		(51,603)
	\$	(6,244,857)	\$	(2,438,638)
Common (unallocated)				
Flow Through	\$	14,664	\$	20,390
Method Life (Protected)		(4,539,526)		(1,772,700)
Other Basis Differences (Unprotected)		(97,819)		(38,200)
	\$	(4,622,681)	\$	(1,805,174)

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission				Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4		
ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)											
1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283. 2. For other (Specify),include deferrals relating to other income and deductions. 3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other. 4. Use footnotes as required.											
Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Electric - Plant	183,430,715	116,870				182.3 & 283	247,402	182.3 & 283	11,604,215	194,904,398 ^(g)
4	Electric - Non-Plant	307,008,928	76,486,821	183,942,303			182.3	8,052,159	182.3	124,962	191,626,249
5											0
9	TOTAL Electric (Total of lines 3 thru 8)	490,439,643	76,603,691	183,942,303				8,299,561		11,729,177	386,530,647 ^(g)
10	Gas										
11	Gas	75,202,645	13,435,072	33,491,544			182.3 & 283	500,003	182.3 & 283	1,826,284	56,472,454
17	TOTAL Gas (Total of lines 11 thru 16)	75,202,645	13,435,072	33,491,544				500,003		1,826,284	56,472,454
18	TOTAL Other	(286,113)			(14,404)						(300,517)
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	565,356,175	90,038,763	217,433,847	(14,404)			8,799,564		13,555,461	442,702,584 ^(g)
20	Classification of TOTAL										
21	Federal Income Tax	390,478,899	62,670,577	152,026,494	(9,973)		182.3 & 283	7,919,668	182.3 & 283	8,955,756	302,149,097
22	State Income Tax	174,877,276	27,368,186	65,407,353	(4,431)		182.3 & 283	879,896	182.3 & 283	4,599,705	140,553,487
23	Local Income Tax										
NOTES											

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther					
		Balance at Beginning of Year	410.1 & Adjustments	Balance at End of Year	
Electric Distribution Plant	\$	149,979	\$	4,690,265	\$
Electric General Plant		398,443		1,252,807	
Electric Intangible Plant		10,125,170		(13,097,255)	
Electric Nuclear Production Plant		1,266,906		8,550,246	
Electric Production Plant		—		391,587	
Electric Transmission Plant		49,800		1,078,272	
Common (Allocation to Electric)		41,412,728		(2,749,052)	
Regulatory Differences - AFUDC Equity		130,027,689		11,356,813	
Total Electric Plant Related Only	\$	183,430,715	\$	11,473,683	\$
The flowback of permanent items included in FERC 283 is \$8,430,244 for 2024 and \$10,149,527 for 2025.					
(b) Concept: AccumulatedDeferredIncomeTaxesOther					
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 of non-property related items, and a prorated balance of property-related items in the formula. An adjustment is made to eliminate any accumulated deferred income tax balances related to regulatory differences related to income taxes.					
(c) Concept: AccumulatedDeferredIncomeTaxesOther					
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) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)		
			Account Credited (c)	Amount (d)				
1	Deferred Tax Collected in Rates in Excess of Current Tax Accrual Levels	1,094,967,286	282	53,232,912		1,041,734,374		
2	Department of Energy Settlement Payment - MN Docket E002/M-24-372	648			19,947,539	19,948,187		
3	Derivatives and Hedging - Retail Electric & Gas	21,451,582			43,882,207	65,333,789		
4	Electric Low Income Discount Program and PowerON Program - MN Docket E-002/GR-15-826 - MN Docket E-002/M-04-1956 - MN Docket E-002/M-17-629	15,677,471	^(a) Various	31,577,071	39,745,429	23,845,829		
5	Gain on Sale of Assets	420,721	254	420,721				
6	Gas Low Income Discount Program - MN Docket G-002/GR-06-1429	904,096	^(a) Various	4,337,870	4,766,879	1,333,105		
7	ITC Gross-Up to Pre-Tax Rate Levels	5,234,148	190	527,624		4,706,524		
8	Minnesota Electric Automatic Bill Credit Rider - MN Docket E-002/M-24-173	5,400,000	142	2,203,964		3,196,036		
9	Minnesota Deferred Electric Commodity Costs - MN Docket E-002/AA-23-153 - MN Docket E-002/AA-24-63	282,190,450	557	1,096,837,496	1,015,907,784	201,260,738		
10	Minnesota Deferred Electric Property Tax - 2024 - MN Docket E-002/GR-21-630	23,226,621	142	23,044,874	402,141	583,888		
11	Minnesota Credit Card Fee Tracker - Electric- MN Docket E-002/GR-24-320- Amortized over 3 years (01/2025-12/2027)	5,428,703	456	1,775,000	1,052	3,654,755		
12	Minnesota Credit Card Fee Tracker - Gas - MN Docket G-002/GR-23-413	1,390,025			1,339,502	2,729,527		
13	Minnesota Electric Conservation and Energy Management Program Costs - MN Docket E-002/M-25-50 - Generally amortized over 12 month period following the expenditure	41,404,717	232	165,759,029	128,333,536	3,979,224		
14	Minnesota Gas Conservation and Energy Management Program Costs - MN Docket G-002/M-25-47 - Generally amortized over 12 month period following the expenditure		232		4,109,729	4,109,729		
15	Minnesota Incentive Compensation Refund- MN Docket E-002/M-23-468	6,244,753	142	6,548,130	611,049	307,672		
16	Minnesota Natural Gas Innovation Act Rider - MN Docket G-002/M-25-402				3,151,508	3,151,508		
17	Minnesota Participant Compensation- MN Docket G-002/GR-23-413	54,729			84,600	139,329		
18	Minnesota Net Operating Loss - MN Docket E-002/GR-21-630	4,500,000	142	4,477,874	48,320	70,446		
19	Minnesota Service Quality Program - MN Docket E,G-002/CI-02-2034 - MN Docket E,G-002/M-12-383	3,175,002	456	943,233	1,668,283	3,900,052		
20	Minnesota Renewable Energy Standard Rider- MN Docket E-002/M-24-353	13,159,267	407.3	3,559,462		9,599,805		
21	Minnesota Transmission Cost Recovery Rider- MN Docket E-002/GR-25-386	7,523,242	407.4	6,955,060		568,182		
22	Nonplant Excess ADIT	14,195,521	190	4,500,018		^(a) 9,695,503		
23	North Dakota Deferred Electric Commodity Costs - ND Docket PU-24-011	3,981,449	557	61,754,228	62,582,205	4,809,426		
24	North Dakota Earnings Sharing - ND Docket PU-20-441 - ND Docket PU-21-160 - ND Docket PU-22-183	14,541,425	254	14,541,425	781,000	781,000		
25	North Dakota Environmental Cleanup - ND Docket PU-17-894	10,584	182.3	10,584				
26	North Dakota Electric Bill Credit Rider - ND Docket PU-24-362		142	17,488,908	26,688,041	9,199,133		
27	North Dakota ITC	8,617,380	410.1	4,657,598		3,959,782		
28	North Dakota Nuclear PTCs	12,396,629	254	6,744,291	139,706	5,792,044		

29	North Dakota Production Tax Credit Levelization - ND Docket PU-20-441 - ND Docket PU-23-312	37,809,568			9,495,596	47,305,164
30	North Dakota Renewable Energy Rider - ND Docket PU-24-341				615,925	615,925
31	North Dakota Retail Asset and Non-Asset Margin Sharing - ND Docket PU-10-657	4,465,571	557	5,753,827	5,548,574	4,260,318
32	Power Purchase Agreement	532,056				532,056
33	Pre-ARO Decommissioning	2,103,696,455			99,442,418	2,203,138,873
34	Renewable*Connect Classic - MN Docket E-002/GR-24-147	1,202,665	^(a) Various	3,268,720	3,337,764	1,271,709
35	Renewable*Connect Government - MN Docket E-002/GR-24-147	16,720	555	359,821	343,101	
36	Renewable*Connect Flex - MN Docket E-002/GR-24-147	1,513,520	^(a) Various	17,470,321	20,429,335	4,472,534
37	Sherco 3 Replacement Costs - MN Docket E-002/AA-18-373	47,068,747	^(a) Various	47,956,813	888,066	
38	South Dakota Deferred Electric Commodity Costs - SD Docket EL 14-058 - SD Docket EL 22-017	20,933,230	^(a) Various	76,551,790	57,738,700	2,120,140
39	South Dakota Infrastructure - SD Docket EL 24-029	1,104,033	407.3		8,796,650	9,900,683
40	South Dakota Property Tax Collected in the Fuel Clause Adjustment - SD Docket EL 14-058 - SD Docket EL 22-017	1,360,328	407.4	1,109,770		250,558
41	South Dakota Retail Asset and Non-Asset Margin Sharing - SD Docket EL 14-058 - SD Docket EL 22-017	1,396,958	557	6,289,941	6,033,751	1,140,768
42	Transmission Formula Rates	14,572,580	456	12,261,939	8,053,126	10,363,767
43	Unrealized Gains on Decommissioning Trust	983,875,159			250,624,378	1,234,499,537
44	WindsorSource - MN Docket E-002/M-01-1479 - MN Docket E-002/GR-13-868	1,817	555	1,620	113	310
41	TOTAL	4,805,645,856		1,682,921,934	1,825,538,007	4,948,261,929

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment				
Accounts charged:			\$	30,661,657
142				915,414
254				
Total			\$	31,577,071

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment				
Accounts charged:			\$	4,081,338
142				256,532
232				
Total			\$	4,337,870

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment				
Accounts charged:			\$	3,239,638
555				29,082
912				
Total			\$	3,268,720

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment				
Accounts charged:			\$	17,353,657
555				116,664
912				
Total			\$	17,470,321

(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment				
Accounts charged:			\$	51,061,965
142				(3,105,152)
254				
Total			\$	47,956,813

(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment				
Accounts charged:			\$	63,614,296
557				12,937,494
254				
Total			\$	76,551,790

(g) Concept: OtherRegulatoryLiabilities				
	Excess Nonplant ADIT - Regulatory Liability*	Gross-Up		Total
Electric	\$ 6,469,045	\$ 2,526,184	\$	8,995,229
Gas	503,612	196,662		700,274
Total	\$ 6,972,657	\$ 2,722,846	\$	9,695,503
*For purposes of calculating 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 12/31/2024	Amortization 2025	Excess Balance 12/31/2025	
Pension Expense	\$ 12,088,085	\$	(1,511,011)	\$ 10,577,074
Total Electric	\$ 12,088,085	\$	(1,511,011)	\$ 10,577,074

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
Electric Operating Revenues								
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. 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 page 108, 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.								
Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)	
1	Sales of Electricity							
2	(440) Residential Sales	1,777,533,259	1,616,662,430	10,813,601	10,232,245	1,420,807	1,405,248	
3	(442) Commercial and Industrial Sales							
4	Small (or Comm.) (See Instr. 4)	1,761,535,762	1,567,900,546	14,241,326	14,019,794	164,199	163,166	
5	Large (or Ind.) (See Instr. 4)	706,836,204	736,896,153	7,478,806	7,628,739	526	531	
6	(444) Public Street and Highway Lighting	30,083,252	27,155,316	102,793	106,083	7,128	6,940	
7	(445) Other Sales to Public Authorities	11,078,654	9,733,875	76,323	75,986	1,598	1,591	
8	(446) Sales to Railroads and Railways							
9	(448) Interdepartmental Sales	479,227	759,663	2,860	6,552			
10	TOTAL Sales to Ultimate Consumers	4,287,546,358	3,959,107,983	32,715,709	32,069,399	1,594,258	1,577,476	
11	(447) Sales for Resale	137,701,746	143,353,969	11,853,880	17,275,121			
12	TOTAL Sales of Electricity	4,425,248,104	4,102,461,952	44,569,589	49,344,520	1,594,258	1,577,476	
13	(Less) (449.1) Provision for Rate Refunds	14,435,322	(168,890,426)					
14	TOTAL Revenues Before Prov. for Refunds	4,410,812,782	4,271,352,378	44,569,589	49,344,520	1,594,258	1,577,476	
15	Other Operating Revenues							
16	(450) Forfeited Discounts	8,564,243	8,464,271					
17	(451) Miscellaneous Service Revenues	2,599,421	2,477,218					
18	(453) Sales of Water and Water Power							
19	(454) Rent from Electric Property	4,868,116	5,549,760					
20	(455) Interdepartmental Rents							
21	(456) Other Electric Revenues	590,756,719	212,744,480					
22	(456.1) Revenues from Transmission of Electricity of Others	364,782,347	333,085,326					
23	(457.1) Regional Control Service Revenues							
24	(457.2) Miscellaneous Revenues							
25	Other Miscellaneous Operating Revenues							
26	TOTAL Other Operating Revenues	971,570,846	562,321,055					

27	TOTAL Electric Operating Revenues	5,382,383,628	4,833,673,433				
Line12, column (b) includes \$ 30,991,161 of unbilled revenues. Line12, column (d) includes 278,866 MWH relating to unbilled revenues							

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4																																																																					
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<table><tr><td>Connection charges</td><td>\$</td><td>2,733,484</td></tr><tr><td>NSF Check Fees</td><td></td><td>501,268</td></tr><tr><td>Billing Concessions</td><td></td><td>(656,041)</td></tr><tr><td>Other, less than \$250,000 each</td><td></td><td>20,710</td></tr><tr><td></td><td>\$</td><td>2,599,421</td></tr></table>				Connection charges	\$	2,733,484	NSF Check Fees		501,268	Billing Concessions		(656,041)	Other, less than \$250,000 each		20,710		\$	2,599,421																																																						
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	\$	2,599,421																																																																						
(c) Concept: RentFromElectricProperty																																																																								
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.																																																																								
(d) Concept: OtherElectricRevenue																																																																								
<table><tr><td colspan="3">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.</td></tr><tr><td>Fixed Production Expense</td><td>\$</td><td>214,929,121</td></tr><tr><td>Variable Production Expense</td><td></td><td>193,643,532</td></tr><tr><td>Total Interchange Agreement</td><td>\$</td><td>408,572,653</td></tr></table> Also includes the following items: <table><tr><td>Change in net over-recovered electric commodity costs</td><td>\$</td><td>220,464,521</td></tr><tr><td>Renewable*Connect</td><td></td><td>27,424,855</td></tr><tr><td>North Dakota Earnings Sharing Refund *</td><td></td><td>12,889,164</td></tr><tr><td>Fees charged to burn Refuse Derived Fuel</td><td></td><td>7,789,047</td></tr><tr><td>North Dakota Other Electric Refund *</td><td></td><td>4,990,774</td></tr><tr><td>Net distribution of commodity trading margins under Joint Operating Agreement</td><td></td><td>2,407,757</td></tr><tr><td>Minnesota Credit Card Fee Tracker</td><td></td><td>1,773,948</td></tr><tr><td>Purchased Power Reimbursement</td><td></td><td>861,434</td></tr><tr><td>Distribution Facility Fixed Charges</td><td></td><td>695,484</td></tr><tr><td>Solar Gardens-Subscribed</td><td></td><td>467,865</td></tr><tr><td>Work on Customers' Equipment</td><td></td><td>315,184</td></tr><tr><td>Facilities Agreement</td><td></td><td>212,410</td></tr><tr><td>North Dakota Earnings Sharing Liability</td><td></td><td>(781,000)</td></tr><tr><td>Solar Energy Standard Exclusion</td><td></td><td>(2,068,774)</td></tr><tr><td>Service Quality Plans</td><td></td><td>(2,094,753)</td></tr><tr><td>Conservation Improvement Program incentive, net of accruals and recoveries</td><td></td><td>(12,728,211)</td></tr><tr><td>Nuclear Production Tax Credits Deferral</td><td></td><td>(82,344,791)</td></tr><tr><td>Other less than \$250,000 each</td><td></td><td>1,909,152</td></tr><tr><td></td><td>\$</td><td>590,756,719</td></tr></table> *Represents reclass between FERC 440-448 and FERC 456				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	\$	214,929,121	Variable Production Expense		193,643,532	Total Interchange Agreement	\$	408,572,653	Change in net over-recovered electric commodity costs	\$	220,464,521	Renewable*Connect		27,424,855	North Dakota Earnings Sharing Refund *		12,889,164	Fees charged to burn Refuse Derived Fuel		7,789,047	North Dakota Other Electric Refund *		4,990,774	Net distribution of commodity trading margins under Joint Operating Agreement		2,407,757	Minnesota Credit Card Fee Tracker		1,773,948	Purchased Power Reimbursement		861,434	Distribution Facility Fixed Charges		695,484	Solar Gardens-Subscribed		467,865	Work on Customers' Equipment		315,184	Facilities Agreement		212,410	North Dakota Earnings Sharing Liability		(781,000)	Solar Energy Standard Exclusion		(2,068,774)	Service Quality Plans		(2,094,753)	Conservation Improvement Program incentive, net of accruals and recoveries		(12,728,211)	Nuclear Production Tax Credits Deferral		(82,344,791)	Other less than \$250,000 each		1,909,152		\$	590,756,719
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(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers																																																																								
Includes \$73,628,117 reimbursement from NSP-Wisconsin for transmission costs shared under the FERC-approved Interchange Agreement between the companies. See Note 1 to the Financial Statements.																																																																								
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<table><tr><td>Connection charges</td><td>\$</td><td>2,653,053</td></tr><tr><td>NSF Check Fees</td><td></td><td>450,811</td></tr><tr><td>Billing Concessions</td><td></td><td>(722,214)</td></tr><tr><td>Other, less than \$250,000 each</td><td></td><td>95,568</td></tr><tr><td></td><td>\$</td><td>2,477,218</td></tr></table>				Connection charges	\$	2,653,053	NSF Check Fees		450,811	Billing Concessions		(722,214)	Other, less than \$250,000 each		95,568		\$	2,477,218																																																						
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(h) Concept: OtherElectricRevenue																																																																								
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	\$	204,632,199
Variable Production Expense		188,152,416
Total Interchange Agreement	\$	392,784,615
Also includes the following items:		
Renewable*Connect	\$	29,436,218
Fees charged to burn Refuse Derived Fuel		8,368,039
Net distribution of commodity trading margins under Joint Operating Agreement		3,681,903
Purchased Power Reimbursement		865,890
Distribution Facility Fixed Charges		694,619
Manitoba Hydro Energy Service Agreement		593,293
Solar Gardens-Subscribed		480,838
Work on Customers' Equipment		271,991
Transmission Owner's Interconnection Facilities (TOIF) Billings		263,035
Facilities Agreement		212,410
Windsorce Program		(53,677)
Solar Energy Standard Exclusion		(1,702,012)
Service Quality Plans		(2,419,250)
Minnesota Credit Card Fee Tracker		(5,428,703)
Conservation Improvement Program incentive, net of accruals and recoveries		(6,492,873)
Change in net over-recovered electric commodity costs		(8,511,852)
Nuclear Production Tax Credits Deferral		(201,144,170)
Other less than \$250,000 each		844,166
	\$	212,744,480
(i) Concept: RevenuesFromTransmissionOfElectricityOfOthers		
Includes \$67,116,676 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: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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)		
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46	TOTAL				

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Page 310. 2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Minnesota						
2	A00 Water Heating	131	21,280	35	3,743	0.1624	
3	A01 Residential	5,087,451	874,912,131	803,750	6,330	0.1720	
4	A02 Residential Time of Day	10,242	1,442,568	1,283	7,983	0.1408	
5	A03 Residential Underground	3,929,402	663,403,162	424,069	9,266	0.1688	
6	A04 Residential TOD Underground	8,696	1,271,458	636	13,673	0.1462	
7	A05 Energy Control	34,534	3,598,570	3,135	11,016	0.1042	
8	A06 Limited Off Peak	2,178	263,313	356	6,118	0.1209	
9	A07 Auto Protective Lighting	4,297	1,312,165			0.3054	
10	A08 Residential Electric Vehicle	6,974	857,227			0.1229	
11	A72 Resid TOU Pilot-Overhead	30,527	5,240,972	5,531	5,519	0.1717	
12	A74 Resid TOU Pilot-Underground	30,487	5,128,961	3,448	8,842	0.1682	
13	A79 Resid EV Pay-As-You-Go	4,422	443,950	992	4,458	0.1004	
14	A80 Resid EV Pilot Bundled	12,943	1,747,932			0.1350	
15	A81 Resid EV Pilot Pre-Pay	3,017	344,488			0.1142	
16	A82 Resid EV Pilot Bundled Subs	693	86,829			0.1253	
17	A83 Resid EV Pilot Pre-Pay Subs	22	2,868			0.1304	
18	A92 Multi-Dwelling EV Pilot	65	26,830			0.4128	
19	Unbilled-MN-Residential Sales	8,428	6,207,431			0.7365	
20	North Dakota						
21	D01 Residential	596,886	75,833,376	69,860	8,544	0.1270	
22	D02 Residential Time of Day	876	99,250	35	25,029	0.1133	
23	D03 Residential Underground	166,995	20,054,238	13,149	12,700	0.1201	
24	D04 Residential TOD Underground	178	20,893	12	14,833	0.1174	
25	D05 Energy Control	2,713	254,793	283	9,587	0.0939	
26	D10 Limited Off Peak	634	55,662	95	6,674	0.0878	
27	D11 Auto Protective Lighting	264	66,048			0.2502	
28	Unbilled-ND-Residential Sales	(215)	474,410			(2.2066)	
29	South Dakota						
30	E01 Residential	369,085	49,709,031	49,852	7,404	0.1347	
31	E02 Residential Time of Day	97	12,083	11	8,818	0.1246	
32	E03 Residential Underground	498,255	65,884,055	44,057	11,309	0.1322	

33	E04 Residential Time of Day	230	28,993	16	14,375	0.1261
34	E06 Residential Heat Pump	1,665	172,430	100	16,650	0.1036
35	E10 Energy Control	1,141	98,240	101	11,297	0.0861
36	E11 Limited Off Peak	2	220	1	2,000	0.1100
37	E12 Auto Protective Lighting	301	62,648			0.2081
38	Unbilled-SD-Residential Sales	(15)	(1,605,246)			107.0164
41	TOTAL Billed Residential Sales	10,805,403	1,772,456,664	1,420,807	7,605	0.1640
42	TOTAL Unbilled Rev. (See Instr. 6)	8,198	5,076,595			0.6192
43	TOTAL	10,813,601	1,777,533,259	1,420,807	7,611	0.1644

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Page 310. 2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading. 3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers. 4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly). 5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto. 6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.							
Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)	
1	Commercial Sales						
2	Minnesota						
3	A05 Energy Control	1,660	166,108	109	15,229	0.1001	
4	A06 Limited Off Peak	1,520	288,421	84	18,095	0.1898	
5	A07 Auto Protective Lighting	20,301	4,135,901			0.2037	
6	A09 Small General Service	25	11,355	98	255	0.4542	
7	A10 Small General Service	712,740	110,444,294	77,138	9,240	0.1550	
8	A11 Water Heating	208	30,683	68	3,059	0.1475	
9	A12 Small General TOD Service	37,418	5,139,440	3,026	12,365	0.1374	
10	A13 Direct Current	(108)	(14,182)	1	(108,000)	0.1313	
11	A14 General Service	7,087,083	931,623,623	44,010	161,033	0.1315	
12	A15 General TOD Service	2,539,006	279,695,475	4,717	538,267	0.1102	
13	A16 Small General kWh metered	16,239	2,317,523	3,146	5,162	0.1427	
14	A18 Small General TOD Service	25,321	3,699,370	4,027	6,288	0.1461	
15	A22 Small General TOD Low Wattage	901	135,966	2	450,500	0.1509	
16	A23 Peak Control Tiered	905,935	113,733,964	1,238	731,773	0.1255	
17	A24 Peak Control Time of Day	432,430	43,010,286	211	2,049,431	0.0995	
18	A25 General TOU - Pilot	17,198	1,509,275	10	1,719,800	0.0878	
19	A26 General TOU - Pilot CPP	34,150	2,655,284	1	34,150,000	0.0778	
20	A27 Tier 1 Energy Control	22,471	2,091,249	5	4,494,200	0.0931	
21	A29 Hiawatha Light Rail	25,824	3,238,316	30	860,800	0.1254	
22	A85 Solar Photo Voltaic		1,608,491				
23	A86 Solar Photo Voltaic		54,956				
24	A87 - EV Fleet Pilot Service	359	192,371			0.5359	
25	A90 - EV Public Charging Pilot	1,992	674,055	13	153,231	0.3384	
26	Unbilled-MN-Commercial Sales	352,700	33,063,683			0.0937	
27	North Dakota						
28	D05 Energy Control	970	88,634	48	20,208	0.0914	
29	D10 Limited Off Peak	363	48,081	35	10,371	0.1325	
30	D11 Auto Protective Lighting	2,290	396,040			0.1729	
31	D12 Small General Service	88,751	12,159,236	8,109	10,945	0.1370	
32	D14 Small General TOD Service	2,597	329,374	195	13,318	0.1268	

33	D16 General Service	638,072	73,901,370	4,074	156,621	0.1158
34	D17 General TOD Service	94,723	9,470,047	196	483,281	0.1000
35	D18 Small General TOD Service	548	78,018	99	5,535	0.1424
36	D19 Small General kWh metered	1,081	160,292	200	5,405	0.1483
37	D20 Peak Control	28,766	3,433,610	44	653,773	0.1194
38	D21 Peak Control Time of Day	6,144	706,533	7	877,714	0.1150
39	D22 Tier 1 Energy Control	91,366	8,255,344	51	1,791,490	0.0904
40	D34 Sm General TOD Low Wattage	52	5,638	5	10,400	0.1084
41	Unbilled-ND-Commercial Sales	(454)	444,509			(0.9791)
42	South Dakota					
43	E10 Energy Control	131	11,144	13	10,077	0.0851
44	E11 Limited Off Peak	255	23,359	7	36,429	0.0916
45	E12 Auto Protective Lighting	2,074	358,814			0.1730
46	E13 Small General Service	82,522	10,553,388	8,083	10,209	0.1279
47	E14 Small General TOD Service	2,876	350,947	361	7,967	0.1220
48	E15 General Service	710,777	78,900,007	4,397	161,650	0.1110
49	E16 General TOD Service	175,543	16,564,524	247	710,700	0.0944
50	E20 Peak Control	40,127	4,750,465	72	557,319	0.1184
51	E21 Peak Control Time of Day	24,547	2,167,787	11	2,231,545	0.0883
52	E22 Energy Control	15,962	1,456,221	11	1,451,091	0.0912
53	Unbilled-SD-Commercial Sales	(4,130)	(2,583,527)			0.6256
41	TOTAL Billed Small or Commercial	13,893,210	1,730,611,097	164,199	84,612	0.1246
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	348,116	30,924,665			
43	TOTAL Small or Commercial	14,241,326	1,761,535,762	164,199	86,732	0.1237

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Page 310. 2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Industrial Sales						
2	Minnesota						
3	A14 General Service	188,197	22,644,349	67	2,808,910	0.1203	
4	A15 General TOD Service	4,794,736	457,090,039	288	16,648,389	0.0953	
5	A23 Peak Control Tiered	26,584	2,904,024	9	2,953,778	0.1092	
6	A24 Peak Control Time of Day	1,471,346	140,043,303	97	15,168,515	0.0952	
7	A25 General TOU - Pilot	131,484	10,779,706	6	21,914,000	0.0820	
8	A27 Tier 1 Energy Control	213,098	13,473,870	5	42,619,600	0.0632	
9	A62 - Firm Real Time Pricing						
10	Unbilled-MN-Commercial Sales	(66,755)	(3,196,001)			0.0479	
11	North Dakota						
12	D16 General Service	49,838	3,578,508	8	6,229,750	0.0718	
13	D17 General TOD Service	95,181	8,795,348	5	19,036,200	0.0924	
14	D21 Peak Control Time of Day	127,572	11,973,488	5	25,514,400	0.0939	
15	D22 Tier 1 Energy Control	83,074	7,746,935	8	10,384,250	0.0933	
16	Unbilled-ND-Commercial Sales	(5,704)	(322,753)			0.0566	
17	South Dakota						
18	E15 General Service	23,880	2,411,257	5	4,776,000	0.1010	
19	E16 General TOD Service	302,763	26,017,245	15	20,184,200	0.0859	
20	E20 Peak Control	14,400	1,576,857	5	2,880,000	0.1095	
21	E21 Peak Control Time of Day	33,170	2,816,650	3	11,056,667	0.0849	
22	Unbilled-SD-Commercial Sales	(4,058)	(1,496,621)			0.3688	
41	TOTAL Billed Large (or Ind.) Sales	7,555,323	711,851,579	526	14,363,732	0.0942	
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(76,517)	(5,015,375)				
43	TOTAL Large (or Ind.)	7,478,806	706,836,204	526	14,218,262	0.0945	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenue			
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.			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Page 310. 2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Minnesota						
2	A30 Street Lighting Company Owned	27,712	21,548,113	2,192	12,642	0.7776	
3	A32 Street Lighting Customer Owned	19,267	1,836,040	424	45,441	0.0953	
4	A34 Street Lighting Metered	33,731	3,033,892	3,620	9,318	0.0899	
5	A37 Street Lighting St Paul	903	154,954	1	903,000	0.1716	
6	Unbilled-MN-Street Lighting Sales	(3)	35,790			(11.9300)	
7	North Dakota						
8	D30 Street Lighting Company Owned	639	568,332	63	10,143	0.8894	
9	D31 Street Lighting Customer Owned	8,977	866,095	38	236,237	0.0965	
10	D32 Street Lighting Ornamental	19	1,629	2	9,500	0.0857	
11	D33 Street Lighting Metered	2,669	236,737	169	15,793	0.0887	
12	Unbilled-ND-Street Lighting Sales	18	17,959			0.9977	
13	South Dakota						
14	E30 Street Lighting Company Owned	808	969,453	133	6,075	1.1998	
15	E31 Street Lighting Customer Owned	1,932	219,202	15	128,800	0.1135	
16	E32 Street Lighting Metered	5,490	546,529	383	14,334	0.0995	
17	E33 Street Lighting Ornamental	384	37,597	88	4,364	0.0979	
18	Unbilled-SD-Street Lighting Sales	247	10,930			0.0443	
41	TOTAL Billed Public Street and Highway Lighting	102,531	30,018,573	7,128	14,384	0.2928	
42	TOTAL Unbilled Rev. (See Instr. 6)	262	64,679			0.2469	
43	TOTAL	102,793	30,083,252	7,128	14,421	0.2927	

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 Page 310. 2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	Minnesota						
2	A40 Small Municipal Pumping	6,020	936,336	883	6,818	0.1555	
3	A41 Municipal Pumping	58,333	8,447,051	568	102,699	0.1448	
4	A42 Fire Siren		35,727				
5	Unbilled-MN-Other Sales	(784)	(22,447)			0.0286	
6	North Dakota						
7	D40 Small Municipal Pumping	618	84,907	58	10,655	0.1374	
8	D41 Municipal Pumping	12,545	1,629,705	89	140,955	0.1299	
9	D42 Fire Siren		1,318				
10	Unbilled-ND-Other Sales	(409)	(36,956)			0.0904	
11	South Dakota						
12	E40 Fire Siren		3,013				
41	TOTAL Billed Other Sales to Public Authorities	77,516	11,138,057	1,598	48,508	0.1437	
42	TOTAL Unbilled Rev. (See Instr. 6)	(1,193)	(59,403)			0.0498	
43	TOTAL	76,323	11,078,654	1,598	47,762	0.1452	

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
SALES OF ELECTRICITY BY RATE SCHEDULES							
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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	Interdepartmental						
2	Interdepartmental Sales						
41	TOTAL Billed Interdepartmental Sales	2,860	479,227			0.1676	
42	TOTAL Unbilled Rev. (See Instr. 6)						
43	TOTAL	2,860	479,227			0.1676	

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SALES OF ELECTRICITY BY RATE SCHEDULES							
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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	(Footnote for Instruction 5)						
41	TOTAL Billed Provision For Rate Refunds						
42	TOTAL Unbilled Rev. (See Instr. 6)						
43	TOTAL		14,435,322				

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
SALES OF ELECTRICITY BY RATE SCHEDULES							
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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)	
41	TOTAL Billed - All Accounts	32,436,843	4,256,555,197	1,594,258	20,346	0.1312	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	278,866	30,991,161			0.1111	
43	TOTAL - All Accounts	32,715,709	4,287,546,358	1,594,258	20,346	0.1311	

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesIncludingUnbilledRevenue			
Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:			
A00		\$	3,140
A01			117,227,350
A02			221,092
A03			91,836,187
A04			196,478
A05			852,201
A06			86,452
A07			432,349
A08			158,251
A09			578
A10			16,777,282
A11			4,935
A12			872,865
A13			(4,027)
A14			163,562,071
A15			154,621,528
A16			285,151
A18			598,365
A22			21,301
A23			21,446,651
A24			41,462,678
A25			2,913,583
A26			755,718
A27			5,030,366
A29			602,529
A30			485,537
A32			338,364
A34			481,946
A37			15,903
A40			138,824
A41			1,329,464
A72			675,901
A74			708,042
A79			102,144
A80			300,261
A81			70,261
A82			2,424
A83			85
A85			333,136
A87			8,596
A90			38,492
A92			1,491
Minnesota jurisdiction		\$	624,995,945

Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:		
D01	\$	15,935,410
D02		23,222
D03		4,455,671
D04		4,744
D05		100,328
D10		27,257
D11		53,097
D12		2,374,737
D14		69,214
D16		18,226,959
D17		4,887,853
D18		14,614
D19		28,800
D20		764,078
D21		3,427,151
D22		4,526,921
D30		13,330
D31		187,036
D32		397
D33		55,599
D34		1,404
D40		16,446
D41		330,542
North Dakota jurisdiction	\$	55,524,810
Estimated Fuel Revenue Collected Through Fuel Clause Adjustment:		
E01		8,662,088
E02		2,135
E03		11,670,964
E04		5,313
E06		38,856
E10		29,256
E11		6,387
E12		43,228
E13		1,879,380
E14		64,348
E15		16,882,398
E16		10,711,217
E20		1,247,401
E21		1,284,008
E22		367,812
E30		15,003
E31		36,850
E32		103,810
E33		7,108
South Dakota jurisdiction	\$	53,057,562
Total Company	\$	733,578,316

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
- RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.

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

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means longer than one year but less than five years.

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

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the last line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the last line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	NSP- Wisconsin	RQ									0
2	Citigroup Energy, Inc.	OS	V6				40,400			1,334,045	1,334,045
3	Citigroup Energy, Inc.	SF	V6				3,600		157,671		157,671
4	City of Ada, MN	OS	V6					114,193			114,193
5	City of Ada, MN	LF	V6				4,730		245,585		245,585
6	City of Ada, MN	AD	V6				189			11,786	11,786
7	City of Kasota, MN	OS	V6					63,241			63,241
8	City of Kasota, MN	LF	V6				4,051		242,429		242,429
9	City of Kasota, MN	AD	V6				33			2,307	2,307
10	Dahlberg Light and Power Co	OS	V6				8,410	248,807	183,687		432,494
11	Dahlberg Light and Power Co	SF	V6				100,027		6,360,611		6,360,611
12	Dahlberg Light and Power Co	AD	V6				793			224,175	224,175
13	Direct Energy Marketing	SF	V6				2,192		82,913		82,913
14	Direct Energy Marketing	OS	V6				28,544			807,439	807,439
15	East Texas Electric Cooperative, Inc.	SF	V6				120,585		2,374,319		2,374,319
16	East Texas Electric Cooperative, Inc.	OS	V6				10,815			212,947	212,947
17	Electric Reliability Council of Texas	OS	V6							2,559,836	2,559,836

18	Electric Reliability Council of Texas	SF	V6						82,466		82,466
19	J. Aron & Company LLC	SF	V6				8,800		373,740		373,740
20	J. Aron & Company LLC	OS	V6				93,200			2,982,862	^(u) 2,982,862
21	ICE NGX Canada Inc	OS	V6				572,560			18,002,686	18,002,686 ^(u)
22	ICE NGX Canada Inc	SF	V6				54,040		2,254,904		2,254,904
23	Karbone Energy LLC	OS	V6					28,049			28,049
24	Merrill Lynch Commodities, Inc.	SF	V6				46,800		1,200,660		1,200,660
25	Merrill Lynch Commodities, Inc.	OS	V6				85,200			2,553,686	^(u) 2,553,686
26	Midcontinent Independent System Operator	OS	V6				9,903,949	42,715,716	17,647,264	8,816,470	69,179,450 ^(m)
27	Midcontinent Independent System Operator	AD	V6				61,349	117,379		(277,529)	^(u) (160,150)
28	Morgan Stanley Capital Group, Inc.	OS	V6				18,025			398,353	^(u) 398,353
29	Morgan Stanley Capital Group, Inc.	SF	V6				200,975		4,441,548		4,441,548
30	North Central Power Company, Inc.	OS	V6					178,925			178,925
31	Northwestern Wisconsin Electric Company	OS	V6					1,176,155			1,176,155
32	PJM Interconnection, LLC	SF	V6				484,613		16,916,177	2,866,244	19,782,421 ^(u)
33	^(a) Footnote for 106b										
15	Subtotal - RQ						6,284,787				
16	Subtotal-Non-RQ						11,853,880	44,642,465	52,563,974	40,495,307	137,701,746
17	Total						11,853,880	44,642,465	52,563,974	40,495,307	137,701,746

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale			
Sales for Resales (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.			
(b) Concept: RevenueFromSalesOfElectricityForResale			
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. To address reconciling items between pages 300 (Electric Operating Revenues) and 310 (Sales for Resale), NSP-Minnesota has removed the volumes and dollars associated with the net production Interchange Agreement billings with NSP-Wisconsin. If included, NSP-Minnesota would have reflected 6,284,787 Mwh in column G, \$340,541,704 in column I, and \$340,541,704 in column K. See Note 1 to the Financial Statements.			
(c) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(d) Concept: RevenueFromSalesOfElectricityForResale			
Prior Period Adjustment			
(e) Concept: RevenueFromSalesOfElectricityForResale			
Prior Period Adjustment			
(f) Concept: RevenueFromSalesOfElectricityForResale			
Prior Period Adjustment			
(g) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(h) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(i) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(j) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(k) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(l) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(m) Concept: RevenueFromSalesOfElectricityForResale			
Demand - Resource Adequacy Auction, Other - Ancillary services			
(n) Concept: RevenueFromSalesOfElectricityForResale			
Prior Period Adjustment			
(o) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			
(p) Concept: RevenueFromSalesOfElectricityForResale			
Financial Trading			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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) (c)	
1	1. POWER PRODUCTION EXPENSES			
2	A. Steam Power Generation			
3	Operation			
4	(500) Operation Supervision and Engineering	2,661,971	2,834,215	
5	(501) Fuel	186,655,130	175,428,485	
6	(502) Steam Expenses	11,962,025	14,821,179	
7	(503) Steam from Other Sources			
8	(Less) (504) Steam Transferred-Cr.			
9	(505) Electric Expenses	4,982,333	4,730,394	
10	(506) Miscellaneous Steam Power Expenses	9,725,843	12,113,121	
11	(507) Rents	1,379,962	1,720,279	
12	(509) Allowances			
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	217,367,264	211,647,673	
14	Maintenance			
15	(510) Maintenance Supervision and Engineering	1,294,722	1,437,329	
16	(511) Maintenance of Structures	3,588,125	5,132,920	
17	(512) Maintenance of Boiler Plant	12,052,840	16,892,810	
18	(513) Maintenance of Electric Plant	3,081,181	5,822,855	
18.1	(513.1) Maintenance of Computer Hardware	6,350		
18.2	(513.2) Maintenance of Computer Software	31,454		
18.3	(513.3) Maintenance of Communication Equipment	18,221		
19	(514) Maintenance of Miscellaneous Steam Plant	5,053,931	6,340,754	
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,126,824	35,626,668	
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	242,494,088	247,274,341	
22	B. Nuclear Power Generation			
23	Operation			
24	(517) Operation Supervision and Engineering	38,222,442	27,343,822	
25	(518) Fuel	114,498,542	105,717,834	
26	(519) Coolants and Water	10,272,011	8,507,254	
27	(520) Steam Expenses	65,230,952	58,888,601	
28	(521) Steam from Other Sources			
29	(Less) (522) Steam Transferred-Cr.			
30	(523) Electric Expenses	3,077,536	2,551,012	

31	(524) Miscellaneous Nuclear Power Expenses	137,648,536	137,959,213
32	(525) Rents	7,681,597	6,476,187
33	TOTAL Operation (Enter Total of lines 24 thru 32)	376,631,616	347,443,923
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	7,389,672	6,485,604
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment	25,227,322	22,674,197
38	(531) Maintenance of Electric Plant	16,710,488	14,232,679
38.1	(531.1) Maintenance of Computer Hardware	405,827	
38.2	(531.2) Maintenance of Computer Software	4,615,473	
38.3	(531.3) Maintenance of Communication Equipment	74,531	
39	(532) Maintenance of Miscellaneous Nuclear Plant	47,511,884	39,747,996
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	101,935,197	83,140,476
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	478,566,813	430,584,399
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	27,437	16,269
45	(536) Water for Power	65,717	49,506
46	(537) Hydraulic Expenses	259,251	228,899
47	(538) Electric Expenses	12,822	12,087
48	(539) Miscellaneous Hydraulic Power Generation Expenses	122,516	115,662
49	(540) Rents	36,924	29,040
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	524,667	451,463
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	44	53
54	(542) Maintenance of Structures	35,817	18,191
55	(543) Maintenance of Reservoirs, Dams, and Waterways	94,330	171,879
56	(544) Maintenance of Electric Plant	270,681	39,913
56.1	(544.1) Maintenance of Computer Hardware	3	
56.2	(544.2) Maintenance of Computer Software	128	
56.3	(544.3) Maintenance of Communication Equipment	897	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,511	139
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	403,411	230,175
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	928,078	681,638
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	3,273,647	3,880,128
63	(547) Fuel	155,431,236	191,809,638
64	(548) Generation Expenses	7,371,415	8,059,153

65	(549) Miscellaneous Other Power Generation Expenses	6,688,129	21,360,535
66	(550) Rents	1,525,557	18,983,020
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	174,289,984	244,092,474
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,410,540	1,473,105
70	(552) Maintenance of Structures	4,600,087	7,697,271
71	(553) Maintenance of Generating and Electric Plant	9,626,611	13,941,038
71.1	(553.1) Maintenance of Computer Hardware	2,573	
71.2	(553.2) Maintenance of Computer Software	54,407	
71.3	(553.3) Maintenance of Communication Equipment	297,477	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	927,579	14,395,528
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	16,919,274	37,506,942
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	191,209,258	281,599,416
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	920,506,785	1,043,810,933
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits	8,113,705	
77	(556) System Control and Load Dispatching	1,226,788	1,326,160
78	(557) Other Expenses	83,877,386	74,599,323
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,013,724,664	1,119,736,416
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	60,458	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	607,486	
79.6	(558.4) Rents	1,502,947	
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	2,170,891	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering	37,313	
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment	515,069	
79.11	(558.8) Maintenance of Computer Hardware	4,100	
79.12	(558.9) Maintenance of Computer Software		
79.13	(558.10) Maintenance of Communication Equipment	3,115	
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant	566,388	
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	1,125,985	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	3,296,876	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering	1,736,245	
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses	14,478,338	

79.21	(558.16) Rents	17,339,136	
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)	33,553,719	
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering	108,640	
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment	3,763,268	
79.26	(558.20) Maintenance of Computer Hardware	236	
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment	24,342	
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant	11,649,833	
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)	15,546,319	
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)	49,100,038	
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering	184,459	
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses	4,853,484	
79.36	(559.3) Fuel	7,037,310	
79.37	(559.4) Rents	325,523	
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)	12,400,776	
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering	195,536	
79.41	(559.7) Maintenance of Structures	643,671	
79.42	(559.9) Maintenance of Boilers	2,454,532	
79.43	(559.10) Maintenance of Generating and Electric Equipment	557,818	
79.44	(559.12) Maintenance of Computer Hardware	36,233	
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment	4,314	
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant	1,212,833	
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)	5,104,937	
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)	17,505,713	
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	1,996,825,528	2,079,876,210
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,108,312	7,422,164
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,344,860	5,109,568
87	(561.3) Load Dispatch-Transmission Service and Scheduling	996,561	
88	(561.4) Scheduling, System Control and Dispatch Services	10,883,711	7,906,015
89	(561.5) Reliability, Planning and Standards Development	71,886	32,541
90	(561.6) Transmission Service Studies	44,718	=(90,961)
91	(561.7) Generation Interconnection Studies	444,396	497,991

92	(561.8) Reliability, Planning and Standards Development Services	4,069,483	3,619,872
93	(562) Station Expenses	4,649,536	5,363,869
94	(563) Overhead Lines Expenses	990,885	785,882
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	396,614,888	363,054,825
97	(566) Miscellaneous Transmission Expenses	5,724,329	9,800,404
98	(567) Rents	1,444,446	1,426,373
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	434,388,011	404,928,543
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	182,347	
104	(569.2) Maintenance of Computer Software	1,709,742	
105	(569.3) Maintenance of Communication Equipment	6,178,894	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,936,483	2,520,984
108	(571) Maintenance of Overhead Lines	5,631,258	6,305,878
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	44,836	
111	TOTAL Maintenance (Total of Lines 101 thru 110)	16,683,560	8,826,862
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	451,071,571	413,755,405
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision	200,809	74,910
116	(575.2) Day-Ahead and Real-Time Market Facilitation	233,476	243,791
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance	54,830	52,274
121	(575.7) Market Facilitation, Monitoring and Compliance Services	10,832,537	10,929,696
122	(575.8) Rents	20,690	18,261
123	Total Operation (Lines 115 thru 122)	11,342,342	11,318,932
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	271,289	
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant	9,950	
130	Total Maintenance (Lines 125 thru 129)	281,239	
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	11,623,581	11,318,932

131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	21,763,937	17,166,234
135	(581) Load Dispatching	132,820	816,721
136	(582) Station Expenses	2,589,792	3,041,592
137	(583) Overhead Line Expenses	4,335,032	5,981,809
138	(584) Underground Line Expenses	9,215,578	9,202,149
139	(585) Street Lighting and Signal System Expenses	580,046	523,567
140	(586) Meter Expenses	(546,827)	1,151,242
141	(587) Customer Installations Expenses	3,691,689	2,912,475
142	(588) Miscellaneous Expenses	12,663,641	11,699,392
143	(589) Rents	4,109,173	3,489,118
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	58,534,881	55,984,299
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	222,778	158,310
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,759,158	1,056,055
148.1	(592.2) Maintenance of Computer Hardware	77,861	
148.2	(592.3) Maintenance of Computer Software	2,951,288	
148.3	(592.4) Maintenance of Communication Equipment	2,541,653	
149	(593) Maintenance of Overhead Lines	57,457,728	58,159,954
150	(594) Maintenance of Underground Lines	8,435,241	5,285,043
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems	1,490,101	2,060,462

153	(597) Maintenance of Meters	560,774	597,625
154	(598) Maintenance of Miscellaneous Distribution Plant	35,916	164,040
155	TOTAL Maintenance (Total of Lines 146 thru 154)	75,532,498	67,481,489
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	134,067,379	123,465,788
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	69,292	128,313
160	(902) Meter Reading Expenses	25,515,130	20,966,417
161	(903) Customer Records and Collection Expenses	25,185,861	26,996,944
162	(904) Uncollectible Accounts	20,344,194	18,041,849
163	(905) Miscellaneous Customer Accounts Expenses	218,632	231,692
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	71,333,109	66,365,215
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	106,560,888	161,795,106
169	(909) Informational and Instructional Expenses	1,109,573	1,226,524
170	(910) Miscellaneous Customer Service and Informational Expenses	191,770	305,379
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	107,862,231	163,327,009
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,237,103	4,709,981
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	41,503	37,615
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	4,278,606	4,747,596
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	108,710,205	94,316,697
182	(921) Office Supplies and Expenses	18,105,904	69,308,765
183	(Less) (922) Administrative Expenses Transferred-Credit	84,918,550	80,134,456
184	(923) Outside Services Employed	25,277,902	24,528,067
185	(924) Property Insurance	2,865,296	10,139,893
186	(925) Injuries and Damages	31,469,826	17,066,397
187	(926) Employee Pensions and Benefits	86,754,414	84,636,871
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	14,582,918	11,928,463
190	(929) (Less) Duplicate Charges-Cr.	6,840,884	6,417,105
191	(930.1) General Advertising Expenses	3,294,698	3,359,124
192	(930.2) Miscellaneous General Expenses	4,114,319	5,108,965

193	(931) Rents	8,916,039	58,941,492
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	212,332,087	292,783,173
195	Maintenance		
196	(935) Maintenance of General Plant	1,243,130	805,159
196.1	(935.1) Maintenance of Computer Hardware	58,513,673	
196.2	(935.2) Maintenance of Computer Software	32,054,183	
196.3	(935.3) Maintenance of Communication Equipment	12,926,669	
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	104,737,655	805,159
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	317,069,742	293,588,332
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	3,094,131,747	3,156,444,487

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: OtherExpensesOtherPowerSupplyExpenses Includes \$52,186,664 of fixed costs and \$15,844,285 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.			
(b) Concept: TransmissionOfElectricityByOthers Includes \$164,255,561 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.			
(c) Concept: TransmissionExpenses 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.			
(d) Concept: MeterExpenses Credit balance due to meter transfer install O&M credits.			
(e) Concept: OtherExpensesOtherPowerSupplyExpenses Includes \$50,648,189 of fixed costs and \$14,387,429 of variable costs reimbursed to NSP-Wisconsin for production costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.			
(f) Concept: TransmissionServiceStudies Credit balance due to timing difference between period that cost is incurred and reimbursement.			
(g) Concept: TransmissionOfElectricityByOthers Includes \$151,156,475 of fixed costs reimbursed to NSP-Wisconsin for transmission costs shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.			

Name of Respondent: Northern States Power Company (Minnesota)					This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4					
PURCHASED POWER (Account 555)														
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. 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, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) 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 (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13. 9. Footnote entries as required and provide explanations following all required data.														
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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1	ACE Lincoln Heights Wind Holdings, LLC	AD					9					281		281
2	ACE Lincoln Heights Wind Holdings, LLC	LU					13,240					436,947		436,947
3	Adams Wind Generations	LU					57,241					3,806,526		3,806,526
4	Agassiz Beach, LLC	AD					(98)					(2,953)		(2,953)
5	Agassiz Beach, LLC	LU					3,316					99,496		99,496
6	Apple River Solar, LLC	LU					18,951					895,427		895,427
7	Aurora Distributed Solar, LLC	AD					(119)					(13,331)		(13,331)
8	Aurora Distributed Solar, LLC	LU					186,965					21,413,163		21,413,163
9	Best Power International LLC	LU					1,833					193,724		193,724
10	Big Blue Wind Farm, LLC	AD					(1,048)					(55,836)		(55,836)
11	Big Blue Wind Farm, LLC	LU					70,625					6,664,326		6,664,326
12	Bisson Windfarm, LLC	AD					69					2,362		2,362
13	Bisson Windfarm, LLC	LU					3,712					126,195		126,195
14	Boeve Windfarm, L.L.C.	AD					16					524		524
15	Boeve Windfarm, L.L.C.	LU					4,799					160,778		160,778
16	Cannon Falls Energy Center	AD					(69,463)				498	(171,153)		(170,655)

17	Cannon Falls Energy Center	LU		357			804,931				15,445,172	53,529,553		68,974,725
18	Carleton College	AD					17					575		575
19	Carleton College	LU					4,085					134,785		134,785
20	CG Windfarm, LLC	AD					(129)					(4,397)		(4,397)
21	CG Windfarm, LLC	LU					1,855					63,098		63,098
22	Cisco Wind Energy, L.L.C.	AD										21,932		21,932
23	Cisco Wind Energy, L.L.C.	LU					11,874					752,925		752,925
24	Citigroup Energy, Inc.	OS											8	8
25	Covanta Hennepin Energy Resource Co LP	AD										22,153		22,153
26	Crowned Ridge Wind, LLC	AD					434					6,512		6,512
27	Crowned Ridge Wind, LLC	LU					808,414					16,145,715		16,145,715
28	Dairyland Electric Cooperative Incorporated	LU					17,200					401,104		401,104
29	Dakota Range III, LLC	LU					617,987					11,100,868		11,100,868
30	Danielson Wind Farms, LLC	AD					(79)					(5,241)		(5,241)
31	Danielson Wind Farms, LLC	LU					55,869					3,715,274		3,715,274
32	Deuel Harvest Wind Energy LLC	AD					1,929					36,523		36,523
33	Deuel Harvest Wind Energy LLC	LU					362,546					7,701,213		7,701,213
34	East Ridge group	AD					55					1,820		1,820
35	East Ridge group	LU					16,122					532,017		532,017
36	Electric Reliability Council of Texas	AD					2,186					23		23
37	Electric Reliability Council of Texas	SF					7,745					5,168,553		5,168,553
38	Ewington Energy Systems, LLC	AD					16					46,240		46,240
39	Ewington Energy Systems, LLC	LU					81,500					2,981,672		2,981,672
40	Fenton Power Partners I, L.L.C.	AD										29,464		29,464
41	Fenton Power Partners I, L.L.C.	LU					387,879					37,735,210		37,735,210
42	Fey Windfarm, L.L.C.	AD					45					1,563		1,563
43	Fey Windfarm, L.L.C.	LU					4,190					146,667		146,667
44	Fillmore County Solar Project, LLC	AD					1,506					(48,587)		(48,587)
45	Fillmore County Solar Project, LLC	LU					55,231					3,079,104		3,079,104
46	Garwin McNeilus	AD					(224)					(4,991)		(4,991)
47	Garwin McNeilus	LU					54,688					1,815,654		1,815,654
48	Grant County Windfarm, LLC	AD					(584)					(39,708)		(39,708)
49	Grant County Windfarm, LLC	LU					52,905					3,597,530		3,597,530
50	Great American West Wind, LLC	AD					766					10,154		10,154
51	Great American West Wind, LLC	LU					439,262					6,148,058		6,148,058
52	Hastings Lock & Dam	LU		2			13,998				399,888	213,713		613,601
53	Heartland Divide Wind II, LLC	AD					104					2,165		2,165
54	Heartland Divide Wind II, LLC	LU					798,138					16,877,496		16,877,496
55	Hilltop Power, L.L.C.	LU					775					34,081		34,081
56	JJN Windfarm, LLC	AD					13					441		441
57	JJN Windfarm, LLC	LU					2,744					91,928		91,928

58	Karbone Energy, LLC	LU					13,254					2,746,383		2,746,383
59	Kas Brothers Windfarm, L.L.C.	AD					6					(a)(1) 232		232
60	Kas Brothers Windfarm, L.L.C.	LU					1,459					59,753		59,753
61	K-Brink Windfarm, L.L.C.	AD					32					(a)(1) 1,075		1,075
62	K-Brink Windfarm, L.L.C.	LU					5,661					189,646		189,646
63	Keller Paving & Landscaping, Inc.	LU					196					6,072		6,072
64	KODA Energy, LLC	AD					(206)					(a)(1) (41)		(41)
65	KODA Energy, LLC	LU					6,916					312,932		312,932
66	Lake Benton Power Partners, L.L.C.	AD										(a)(1) 19,204		19,204
67	Lake Benton Power Partners, L.L.C.	LU					234,735					6,904,902		6,904,902
68	Louise Solar Project, LLC	AD					54					(a)(1) 2,635		2,635
69	Louise Solar Project, LLC	LU					92,958					5,182,459		5,182,459
70	LSP Cottage Grove Incorporated	LU		245			555,894				5,481,517	20,085,865		25,567,382
71	Manitoba Hydro	AD					(a)(1) (46,500)							
72	Manitoba Hydro	LU		2,707			810,934				23,105,160	67,848,711		90,953,871
73	Mankato Energy Center I, L.L.C.	AD					(2,823)				93,750	(a)(1) (350,377)		(256,627)
74	Mankato Energy Center I, L.L.C.	LU		375			1,159,279				26,730,418	90,313,019		117,043,437
75	Mankato Energy Center II, L.L.C.	AD					2,671				39,330	(a)(1) (81,982)		(42,652)
76	Mankato Energy Center II, L.L.C.	LU		345			1,224,811				19,634,113	12,826,730		32,460,843
77	Marshall Solar	AD										(a)(1) 2		2
78	Marshall Solar	LU					96,571					7,757,131		7,757,131
79	Merrill Lynch Commodities, Inc.	OS											(a)(1) 21,056	21,056
80	Metro Wind LLC	AD					(3)					(a)(1) (100)		(100)
81	Metro Wind LLC	LU					710					21,317		21,317
82	Midcontinental ISO	AD					15,491					(a)(1) (295,354)		(295,354)
83	Midcontinental ISO	SF					3,533,419					68,827,280		68,827,280
84	MinnDakota Wind LLC	AD					1,672					(a)(1) 37,213		37,213
85	MinnDakota Wind LLC	LU					337,313					7,727,712		7,727,712
86	Miscellaneous	AD	NAEMA										1,855,820 (a)(1) (a)(2)	1,855,820
87	Miscellaneous	OS	NAEMA										(17,716,465) (a)(1)	(17,716,465)
88	Moraine Wind, L.L.C.	AD										(a)(1) 280		280
89	Moraine Wind, L.L.C.	LU					101,628					3,073,088		3,073,088
90	Morgan Stanley Capital Group Inc.	LU					73,000					1,488,387		1,488,387
91	N A E Lakota Ridge, LLC	AD					47					(a)(1) 515		515
92	N A E Lakota Ridge, LLC	LU					13,639					150,036		150,036
93	N A E Shaokatan Hills, LLC	AD					28					(a)(1) 311		311
94	N A E Shaokatan Hills, LLC	LU					11,446					125,902		125,902
95	NAE Shaokatan, LLC	AD										(a)(1) 9		9
96	NAE Shaokatan, LLC	LU					20,439					613,148		613,148
97	Natural Gas Exchange Inc.	OS											26,837,105 (a)(1)	26,837,105

98	North Star Solar	AD										(a) (2,974)		(2,974)
99	North Star Solar	LU					181,202					13,416,939		13,416,939
100	NSP-M Solar Gardens	AD					(54,828)					(a) 44,483,549		44,483,549
101	NSP-M Solar Gardens	LU					1,662,067					163,711,260		163,711,260
102	Odell Wind Farm, LLC	LU					768,537					22,217,564		22,217,564
103	Otter Tail Power Company	OS					1,875					93,750		93,750
104	Pipestone	AD					38					(a) 1,255		1,255
105	Pipestone	LU					1,602					29,067		29,067
106	PJM Interconnection LLC	AD											(b) (b) 76	76
107	PJM Interconnection LLC	OS											(b) 286,084	286,084
108	Poet, LLC	AD					(115)					(a) (2,327)		(2,327)
109	Poet, LLC	LU					202					4,084		4,084
110	Prairie Rose Wind, LLC	LU					460,262					29,133,041		29,133,041
111	Restore Renewables, LLC	LU					1,155					102,544		102,544
112	Ridgewind Power Partners, LLC	AD					(a) 17							
113	Ridgewind Power Partners, LLC	LU					76,104					4,940,926		4,940,926
114	Rock Ridge Power Partners LLC	AD										(a) 430		430
115	Rock Ridge Power Partners LLC	LU					1,390					34,161		34,161
116	Ruthton Ridge	LU					31,994					959,831		959,831
117	SAF Hydroelectric, L.L.C.	LU					30,112					1,752,498		1,752,498
118	Shane's Wind Machine LLC	LU					420					13,866		13,866
119	Shell Energy North America US LP	OS											(b) 4,650,292	4,650,292
120	Slayton Solar, LLC	LU					2,350					242,081		242,081
121	South Ridge Power Partners, LLC	AD										(a) 1,395		1,395
122	South Ridge Power Partners, LLC	LU					2,786					79,717		79,717
123	Southwest Power Pool, Inc.	AD					(111)					(a) (4,027)		(4,027)
124	Southwest Power Pool, Inc.	OS					4,757					174,449		174,449
125	St Cloud	AD										(a) 1		1
126	St Cloud	LU					46,044					1,782,814		1,782,814
127	St. Olaf College	LU					10					338		338
128	St. Paul Cogeneration	LU					74,500					7,301,018		7,301,018
129	Taygete Energy Project, LLC	SF					383,169					9,562,493		9,562,493
130	Tenaska Power Services Co.	OS											(a) 78,300	78,300
131	TG Windfarm, LLC	AD					69					(a) 2,362		2,362
132	TG Windfarm, LLC	LU					3,712					126,195		126,195
133	Tholen Transmission-Trust	AD					74					(a) 2,448		2,448
134	Tholen Transmission-Trust	LU					35,744					1,132,394		1,132,394
135	Tofteland Windfarm, LLC	AD					69					(a) 2,362		2,362
136	Tofteland Windfarm, LLC	LU					3,712					126,195		126,195
137	Uilk Wind Farm, LLC	LU					6,568					362,785		362,785
138	University of Minnesota	LU					1,950					58,361		58,361

139	Valley View Transmission	AD					(776)					b3 (44,273)		(44,273)
140	Valley View Transmission	LU					3,792					437,160		437,160
141	Velva Windfarm, LLC	AD					(486)					b3 (16,027)		(16,027)
142	Velva Windfarm, LLC	LU					20,038					661,249		661,249
143	Western Area Power Administration	AD					1,074					b3 29,975		29,975
144	Western Area Power Administration	LU					11,784					354,369		354,369
145	Westridge Windfarm, LLC	AD					69					b3 2,362		2,362
146	Westridge Windfarm, LLC	LU					3,712					126,195		126,195
147	Windcurrent Farms, L.L.C.	AD					90					b3 3,152		3,152
148	Windcurrent Farms, L.L.C.	LU					4,691					164,196		164,196
149	Windvest Power Partners, LLC	AD										b3 981		981
150	Windvest Power Partners, LLC	LU					638					11,446		11,446
151	Winona County Wind LLC	LU					4,354					291,249		291,249
152	Woodstock Hills, L.L.C.	LU					37,088					785,150		785,150
153	Woodstock Municipal Wind, LLC	LU					798					53,414		53,414
154	Zephyr Wind LLC	LU					88,091					7,667,790		7,667,790
15	TOTAL						17,063,166	0	0	0	90,929,846	813,564,663	16,012,276	920,506,785

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: MegawattHoursPurchasedOtherThanStorage Prior Period Adjustment			
(b) Concept: MegawattHoursPurchasedOtherThanStorage Prior Period Adjustment			
(c) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
(d) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
(e) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
(f) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
(g) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
(h) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
(i) Concept: EnergyChargesOfPurchasedPower Prior Period Adjustment			
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(af) Concept: EnergyChargesOfPurchasedPower
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(aj) Concept: EnergyChargesOfPurchasedPower
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Prior Period Adjustment

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(at) Concept: EnergyChargesOfPurchasedPower
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(au) Concept: EnergyChargesOfPurchasedPower
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(ax) Concept: EnergyChargesOfPurchasedPower
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(ay) Concept: EnergyChargesOfPurchasedPower
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(az) Concept: EnergyChargesOfPurchasedPower
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(ba) Concept: EnergyChargesOfPurchasedPower
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(bb) Concept: EnergyChargesOfPurchasedPower
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(bc) Concept: EnergyChargesOfPurchasedPower
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(bd) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(be) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bf) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bg) Concept: EnergyChargesOfPurchasedPower
Prior Period Adjustment
(bh) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bi) Concept: OtherChargesOfPurchasedPower
Financial Trading

(bj) Concept: OtherChargesOfPurchasedPower
Prior Period Adjustment
(bk) Concept: OtherChargesOfPurchasedPower
Miscellaneous
(bl) Concept: OtherChargesOfPurchasedPower
Miscellaneous
(bm) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bn) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bo) Concept: OtherChargesOfPurchasedPower
Prior Period Adjustment
(bp) Concept: OtherChargesOfPurchasedPower
Financial Trading
(bq) Concept: OtherChargesOfPurchasedPower
Financial Trading
(br) Concept: OtherChargesOfPurchasedPower
Financial Trading

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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.
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.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the 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.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total Revenues (\$) (k+l+m) (n)
1	Buffalo Ridge Wind	Buffalo Ridge Wind	MISO	OS	3751	Buffalo Ridge	Buffalo Ridge						110,316	110,316
2	Great River Energy	Various	Various	FNO	Various	Various	Various				65,861,852		126,983	65,988,835
3	Marshall Solar	Marshall Solar	MISO	OS	3514	Lyon County	Lyon County						142,014	142,014
4	MidAmerican Energy Company	Palo Alto	MISO	OS	3721	Palo Alto	Palo Alto						329,206	329,206
5	Midcontinent ISO (MISO)	Various	Various	FNO	MISO OATT	Various	Various				126,331,776	75,970,750		202,302,526
6	Missouri River Energy Services (MRES)	Various	Various	FNO	304	Various	Various				7,868,034			7,868,034
7	North Star Solar PV LLC	North Star Solar	MISO	OS	2871	Chisago County	Chisago County						427,873	427,873
8	(a) Northern States Power-Minnesota	Blazing Star 2	MISO	OS	3418	Steep Bank Lake	Steep Bank Lake						919,949	919,949
9	Sioux Falls, City of	Western Area Power Administration (WAPA)	Sioux Falls, City of	OS	484	WAPA	Sioux Falls, City of						215,335	215,335
10	South Dakota State Penitentiary (SDSP)	WAPA	SDSP	OS	385	WAPA	SDSP						15,856	15,856
11	Southern MN Municipal Power Agency	Various	Various	FNO	304	Various	Various				9,609,145			9,609,145
12	Stoneray Power	Stoneray Power Partners	MISO	OS	3513	Chanarambie	Chanarambie						292,338	292,338
13	Tenaska Nobles 2 Holdings LLC	Nobles 2 Wind Farm	MISO	OS	3347	Zephyr	Zephyr						1,632,993	1,632,993
14	University of North Dakota (UND)	WAPA	University of North Dakota	OS	440	WAPA	UND						53,061	53,061
15	Walleye Wind, LLC	Walleye Wind	MISO	OS	1495	Rock County	Rock County						559,280	559,280
16	Wisconsin Public Power, Inc. (WPPI)	Minnesota Power Authority	WPPI	OS	466								40,320	40,320
17	North Hills Wind Project, LLC	North Hills	MISO	OS	4424	DPC	Various						647,149	647,149
18	(b) Northern States Power-Wisconsin	(g) Various	Various	OS	437	Various	Various				73,628,117			73,628,117
19	(c) Footnote from page 106b													
35	TOTAL							0	0	0	283,298,924	75,970,750	5,512,673	364,782,347

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: PaymentByCompanyOrPublicAuthority Affiliate - Generation Function of Northern States Power - MN (b) Concept: PaymentByCompanyOrPublicAuthority Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc. (c) Concept: PaymentByCompanyOrPublicAuthority 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. (d) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName Reimbursement from NSP-Wisconsin for transmission costs shared through the FERC- approved Interchange Agreement. See Note 1 - Summary of Significant Accounting Policies in the Notes to the Financial Statements. (e) Concept: StatisticalClassificationCode FNO, LFP, SFP, NF (f) Concept: RateScheduleTariffNumber 28, 304 and OA97-25-000 et al. (g) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers MISO Schedule 26-A revenue (h) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue (i) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Schedule 2 Revenue (j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue (k) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue (l) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue (m) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Affiliate - Interconnection Network Upgrade revenue (n) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Facilities Charge (o) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Facilities Charge (p) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue (q) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue (r) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Facilities Charge (s) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers Interconnection Network Upgrade revenue			

(t) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Meter Charge
(u) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Interconnection Network Upgrade revenue

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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 Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
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47					
48					
49					
40	TOTAL				

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4		
TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)								
1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter. 2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported. 3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications. 4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service. 5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered. 6. Enter ""TOTAL"" in column (a) as the last line. 7. Footnote entries and provide explanations following all required data.								
Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Basin Electric Power	OS					2,400	2,400
2	Central MN Municipal Pw	FNS			1,882,892			1,882,892
3	Dairyland Power	OS					19,744	19,744
4	Great River Energy	FNS			44,922,912			44,922,912
5	ITC Midwest	OS					726,036	726,036
6	McLeod Coop Power	OLF			24,500			24,500
7	Midcontinent ISO (MISO)	LFP			77,587,377	80,589,369		158,176,746
8	MN Municipal Pwr Agy	FNS			1,330,625			1,330,625
9	Minnkota Power Coop	OLF				61,256	780,000	841,256
10	Missouri Riv Engy Serv	FNS			1,622,838		68,699	1,691,537
11	Montana-Dakota Util Co	OS					1,277,562	1,277,562
12	Northwestern Wis Elect	FNS			612,659			612,659
13	Northern States Pwr-MN	OS					919,949	919,949
14	Otter Tail Pwr Co	OS					2,593,643	2,593,643
15	Rochester Public Util	FNS			1,551,860			1,551,860
16	Southern MN Muncipl Pwr	FNS			15,588,663			15,588,663
17	Southwest Power Pool	FNS			58,570	602		59,172
18	Stearns Coop Electric	OS				2,796	461	3,257
19	Verendrye Electric Coop	OLF				133,914		133,914
20	Northern States Pwr-WI	OLF			164,255,561			164,255,561
	TOTAL		0	0	309,438,457	80,787,937	6,388,494	396,614,888

FOOTNOTE DATA
(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Affiliate - Transmission Function of Northern States Power Company - MN
(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers
Northern States Power Company (a Minnesota Corporation) and Northern States Power Company (a Wisconsin Corporation) are both operating company subsidiaries of Xcel Energy, Inc.
(c) Concept: StatisticalClassificationCode
Two year notification required for termination
(d) Concept: StatisticalClassificationCode
LFP, FNS, FNO, OS
(e) Concept: StatisticalClassificationCode
Four year notification required for termination
(f) Concept: StatisticalClassificationCode
OS, LFP - Two year notification required for termination
(g) Concept: StatisticalClassificationCode
Two year notification required for termination
(h) Concept: StatisticalClassificationCode
Reimbursement to NSP-Wisconsin for transmission shared through the FERC-approved Interchange Agreement. See Note 1 to the Financial Statements.
(i) Concept: EnergyChargesTransmissionOfElectricityByOthers
MISO Schedule 26-A expense & MISO Admin FERC fee
(j) Concept: OtherChargesTransmissionOfElectricityByOthers
Meter Agent Service Charges
(k) Concept: OtherChargesTransmissionOfElectricityByOthers
Facility Charges
(l) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge
(m) Concept: OtherChargesTransmissionOfElectricityByOthers
Fixed Transmission Service Charge
(n) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge
(o) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge
(p) Concept: OtherChargesTransmissionOfElectricityByOthers
Affiliate - Interconnection upgrade charge
(q) Concept: OtherChargesTransmissionOfElectricityByOthers
Interconnection upgrade charge
(r) Concept: OtherChargesTransmissionOfElectricityByOthers
Fixed Facility Charge

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)				
Line No.	Description (a)	Amount (b)		
1	Industry Association Dues	1,593,734		
2	Nuclear Power Research Expenses			
3	Other Experimental and General Research Expenses			
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities			
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than \$5,000			
6	Shareholder Related Expenses	357,844		
7	Director Fees and Expenses	1,666,125		
8	SEC Filing Expense	22,075		
9	Research and Development Expense	474,492		
10	Other	49		
46	TOTAL	4,114,319		

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
Depreciation and Amortization of Electric Plant (Account 403, 404, 405)								
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 B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year. 3. Report all available information called for in Section 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 of 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.								
Line No.	A. Summary of Depreciation and Amortization Charges							
	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			15,570		15,570		
2	Steam Production Plant	94,455,781	565,497		(1,036,402)	93,984,876		
3	Nuclear Production Plant	171,998,435	(2,412,145)	10,443,647		180,029,937		
4	Hydraulic Production Plant-Conventional	1,706,851		106,828	(67,064)	1,746,615		
5	Hydraulic Production Plant-Pumped Storage							
5.1	Solar Production Plant	13,112,945	243,974		(566,024)	12,790,895		
5.2	Wind Production Plant	156,695,153	8,646,844		(3,143,985)	162,198,012		
5.3	Other Renewable Production Plant	20,408,899	223,679			20,632,578		
6	Other Production Plant	56,048,682	39,471		(1,068,254)	55,019,899		
7	Transmission Plant	118,807,560	5,255		(1,239,336)	117,573,479		
8	Distribution Plant	230,337,681	234,059		(991,333)	229,580,407		
9	Regional Transmission and Market Operation							
9.1	Energy Storage Plant							
10	General Plant	23,754,452			1,530	23,755,982		
11	Common Plant-Electric	51,855,745	3,467	85,641,115	(4,412)	137,495,915		
12	TOTAL	939,182,184	7,550,101	96,207,160	(8,115,280)	1,034,824,165		
B. Basis for Amortization Charges								
ACCOUNT 404 Column (d) Common Plant-Electric (Software) is amortized over its expected useful life of 3, 5, 7, 10, or 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.								
Line No.	C. Factors Used in Estimating Depreciation Charges							
	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	16,061						
14	311	297,297						
15	312	1,345,579						
16	314	270,464						
17	315	183,989						
18	315.1	6						
19	315.2	382						
20	315.2	96						

21	^(a) 315.3	18					
22	316	52,917					
23	317	76,298					
24	Subtotal Steam Prod	2,243,107					
25	Nuclear Production						
26	320	1,681					
27	321	678,959					
28	322	2,199,732					
29	323	693,959					
30	324	569,964					
31	^(b) 324.1	23,868					
32	⁽ⁱ⁾ 324.2	24,927					
33	⁽ⁱⁱ⁾ 324.2	48,507					
34	^(b) 324.2	4,411					
35	⁽ⁱ⁾ 324.3	626					
36	^(m) 324.3	160					
37	325	214,048					
38	326	(117,688)					
39	Subtotal Nuclear Prod	4,343,154					
40	Hydro Production						
41	330	1,693					
42	331	1,647					
43	332	14,922					
44	333	10,157					
45	334	3,284					
46	^(a) 334.1						
47	335	134					
48	336	368					
49	337						
50	Subtotal Hydro Prod	32,205					
51	Solar Production						
52	338.12	4,103					
53	338.1	1,826					
54	338.2	6,846					
55	338.4	267,170					
56	338.5	12,855					
57	338.6	4,730					
58	338.7	42,781					
59	338.8	1,217					

60	338.9 ^(a)	159				
61	338.10 ^(a)	1,060				
62	338.10 ^(a)	2,023				
63	338.13	6,721				
64	Subtotal Solar Prod	351,491				
65	Wind Production					
66	338.20	14,968				
67	338.21	162,348				
68	338.23	1,529,595				
69	338.24	226,497				
70	338.26	49,521				
71	338.27	311				
72	338.29	29,006				
73	338.30 ^(a)	3,468				
74	338.31 ^(a)	1,158				
75	338.31 ^(a)	739				
76	338.32 ^(a)	952				
77	338.32 ^(a)	5,972				
78	338.32 ^(a)	1,202				
79	338.33	8,271				
80	338.34	150,871				
81	Subtotal Wind Prod	2,184,879				
82	Other Renewable Generation Production					
83	339.12	847				
84	339.1	628				
85	339.2	14,570				
86	339.3	6,907				
87	339.4	49,939				
88	339.6	12,634				
89	339.8	4,036				
90	339.9 ^(a)	25				
91	339.13	1,328				
92	Subtotal Orwn Prod	90,914				
93	Other Production					
94	340	20,407				
95	341	350,827				
96	342	32,090				
97	343	154,157				

98	344	2,784,499					
99	345	297,949					
100	^(j) 345.1	212					
101	^(k) 345.2	109					
102	^(l) 345.3	157					
103	^(m) 345.3	4					
104	346	56,663					
105	347	161,263					
106	348						
107	Subtotal Other Prod	3,858,337					
108	Transmission						
109	350	191,236					
110	⁽ⁿ⁾ 351.1	356					
111	^(o) 351.2	465					
112	^(p) 351.2	1,657					
113	^(q) 351.2	21,482					
114	^(r) 351.2	1,065					
115	^(s) 351.3	246					
116	^(t) 351.3	19,779					
117	^(u) 351.3	45,526					
118	352	180,513					
119	353	1,753,054					
120	354	126,487					
121	355	1,862,325					
122	356	896,969					
123	357	32,182					
124	358	37,009					
125	359	5,374					
126	359.1	173					
127	Subtotal Transmission	5,175,898					
128	Distribution						
129	360	20,985					
130	361	73,034					
131	362	909,825					
132	^(v) 363.1	2,791					
133	^(w) 363.2	9,550					
134	^(x) 363.2	1,661					

135	^(ان) 363.2	7,692					
136	^(ان) 363.2	11,438					
137	^(ان) 363.3	157					
138	^(ان) 363.3	8,733					
139	^(ان) 363.3	3,568					
140	^(ان) 363.3	40,578					
141	^(ان) 363.3	19,340					
142	364	929,401					
143	365	829,477					
144	366	442,671					
145	367	1,602,455					
146	^(ان) 368	696,528					
147	^(ان) 368	29,520					
148	^(ان) 369	125,954					
149	^(ان) 369	374,397					
150	370	331,316					
151	371	19,068					
152	373	111,556					
153	374	12,231					
154	Subtotal Distribution	6,613,926					
155	General						
156	389	22,534					
157	^(ان) 390	213,134					
158	^(ان) 390	^(ان) 1,075					
159	^(ان) 391	29,791					
160	^(ان) 391	41,366					
161	^(ان) 392	9,401					
162	^(ان) 392	64,725					
163	^(ان) 392	31,723					
164	^(ان) 392	147,134					
165	393	1,881					
166	394	168,141					
167	395	2,042					
168	396	99,265					
169	^(ان) 397	3,002					
170	^(ان) 397	36,439					

171	(b)(1) 397	3,568					
172	(b)(1) 397	65,072					
173	(b)(1) 397	39,732					
174	(b)(1) 397.1	7,276					
175	(b)(1) 397.2	4,954					
176	(b)(1) 397.2	9,347					
177	(b)(1) 397.2	4,519					
178	(b)(1) 397.3	81					
179	(b)(1) 397.3						
180	(b)(1) 397.3	11,146					
181	398	1,796					
182	Subtotal General	1,019,144					
183	TOTAL	(b)(1)25,913,055					

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments			
Transmission Serving Production		\$	4,127,656
(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments			
Distribution Serving Production		\$	95,384
(c) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments			
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		\$	(4,633,263)
Transmission Plant			(4,171,205)
General Plant			(37,768)
Total		\$	<u>(8,842,236)</u>
(d) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
315.1 Computer Hardware			
(e) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
315.2 Computer Software - 5 Year			
(f) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
315.2 Computer Software - 7 Year			
(g) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
315.3 Communication Equipment - Two Way			
(h) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
324.1 Computer Hardware			
(i) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
324.2 Computer Software - 10 Year			
(j) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
324.2 Computer Software - 5 Year			
(k) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
324.2 Computer Software - 7 Year			
(l) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
324.3 Communication Equipment			
(m) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
324.3 Communication Equipment - Two Way			
(n) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
334.1 Computer Hardware			
(o) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
338.9 Computer Hardware			
(p) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
338.10 Computer Software - 10 Year			
(q) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges			
338.10 Computer Software - 7 Year			

(r) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
338.30 Computer Hardware
(s) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
338.31 Computer Software - 5 Year
(t) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
338.31 Computer Software - 7 Year
(u) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
338.32 Communication Equipment
(v) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
338.32 Communication Equipment - Two Way
(w) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
338.32 Communication Equipment - EMS
(x) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
339.9 Computer Hardware
(y) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
345.1 Computer Hardware
(z) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
345.2 Computer Software - 5 Year
(aa) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
345.3 Communication Equipment
(ab) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
345.3 Communication Equipment - Two Way
(ac) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.1 Computer Hardware
(ad) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.2 Computer Software - 10 Year
(ae) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.2 Computer Software - 3 Year
(af) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.2 Computer Software - 5 Year
(ag) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.2 Computer Software - 7 Year
(ah) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.3 Communication Equipment
(ai) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.3 Communication Equipment - Two Way
(aj) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
351.3 Communication Equipment - EMS
(ak) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.1 Computer Hardware
(al) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.2 Computer Software - 10 Year

(am) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.2 Computer Software - 3 Year
(an) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.2 Computer Software - 5 Year
(ao) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.2 Computer Software - 7 Year
(ap) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.3 Communication Equipment
(aq) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.3 Communication Equipment - Two Way
(ar) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.3 Communication Equipment - AMR
(as) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.3 Communication Equipment - AGIS
(at) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
363.3 Communication Equipment - EMS
(au) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
368 Line Transformers
(av) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
368 Line Capacitors
(aw) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
369 Overhead Services
(ax) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
369 Underground Services
(ay) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
390 Structures and Improvements
(az) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
390 Structures and Improvements - Leasehold Improvements
(ba) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
391 Office Furniture and Equipment
(bb) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
391 Network Equipment
(bc) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
392 Transportation Equipment - Automobiles
(bd) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
392 Transportation Equipment - Light Trucks
(be) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
392 Transportation Equipment - Trailers
(bf) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges
392 Transportation Equipment - Heavy Trucks 392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1).

		Charged to Clearing Accounts		Depreciable Plant Base	
392 Transportation Equipment	\$	20,325,304	\$	252,983,000	
396 Power Operated Equipment		12,576,192		99,265,000	
Total	\$	32,901,496	\$	352,248,000	
(bg) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397 Communication Equipment					
(bh) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397 Communication Equipment - Two Way					
(bi) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397 Communication Equipment - AMR					
(bj) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397 Communication Equipment - EMS					
(bk) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397 Communication Equipment - Smart Grid					
(bl) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.1 Computer Hardware					
(bm) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.2 Computer Software - 3 Year					
(bn) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.2 Computer Software - 5 Year					
(bo) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.2 Computer Software - 7 Year					
(bp) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.3 Communication Equipment					
(bq) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.3 Communication Equipment - Two Way					
(br) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges					
397.3 Communication Equipment - EMS					
(bs) Concept: DepreciablePlantBase					
Account 390 Structures and Improvements - Leasehold Improvements is computed using an end of life method rather than a specific rate.					
(bt) Concept: DepreciablePlantBase					
(1)	Column (b) Computation: Depreciable Plant Balances are an average of the beginning and ending plant balance for the year.				

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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. 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 columns (f), (g), and (h), expenses incurred during the 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			
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	MINNESOTA PUBLIC UTILITIES COMMISSION											
2	Electric Assessments	12,834,121		12,834,121		Elec	928	11,058,550				
3	Gas Assessments					Gas	928	1,775,571				
4	E002/GR-21-630 2022 Electric Rate Increase	98,313		98,313		Elec	928			186	98,313	
5	G002/GR-23-413 2024 Natural Gas Rate Increase - Amortized through 2026	783,097		783,097		Gas	928			186	783,097	
6	E002/GR-24-320 2025 Electric Rate Case - Amortized through 2027	1,639,970		1,639,970		Elec	928			186	1,639,970	
7	E999/AA-18-373 Sherco Unit 3 Replacement Cost	37,602	1,416	39,018		Elec	928	39,018				
8	E002/C-23-424 Technical Planning Standards Appeal		20,032	20,032		Elec	928	20,032				
9	E002/AA-22-179 2023 Prairie Island Outage Prudence Case		340,659	340,659		Elec	928	340,659				
10	E002/M-13-867 Community Solar Garden Bill Credit Change		90,357	90,357		Elec	928	90,357				
11	E002/SA-25-129 Slayton, MN Municipalization Contested Case		227,516	227,516		Elec	928	227,516				
12	Electric Miscellaneous - Minnesota	136,170		136,170		Elec	928	108,785				
13	Gas Miscellaneous - Minnesota					Gas	928	27,385				
14	NORTH DAKOTA PUBLIC SERVICE COMMISSION											
15	Gross Receipts Tax Assessment Electric	52,688		52,688		Elec	928	38,924				
16	Gross Receipts Tax Assessment Gas					Gas	928	13,764				
17	Assessments	(184,712)		(184,712)		Elec	928	(184,712)				
18	PU-23-367 2024 Natural Gas Rate Increase - Amortized through 2027	272,500		272,500		Gas	928			186	272,500	
19	PU-24-376 2025 Electric Rate Case - Amortized through 2028	428,695		428,695		Elec	928			186	428,695	
20	PU-25-257 2026 Transmission Cost Rider Rate Adjustment	10,000		10,000		Elec	928	10,000				
21	PU-25-248 2026 Renewable Energy Rider Rate Adjustment	10,000		10,000		Elec	928	10,000				
22	Miscellaneous	1,145		1,145		Elec	928	1,058				
23						Gas	928	87				
24	SOUTH DAKOTA PUBLIC UTILITIES COMMISSION											
25	Gross Receipts Tax Assessment	402,560		402,560		Elec	928	402,560				
26	EL-25-031 2026 Transmission Cost Recovery Rate Adjustment	2,692		2,692		Elec	928	2,692				

27	EL25-033 2026 Infrastructure Rider Project Eligibility and Factor Update	5,664		5,664		Elec	928	5,664				
28	EL22-017 2022 SD Electric Rate Increase - Amortized through 2025	238,643		238,643		Elec	928			186	238,643	
29	Other											
30	FEDERAL ENERGY REGULATORY COMMISSION											
31	EL22-78 MISO Complaint	244		244		Elec	928	244				
32	Miscellaneous - Electric	164	16,183	16,347		Elec	928	5,950				
33	Miscellaneous - Gas					Gas	928	10,397				
46	TOTAL	16,769,556	696,163	17,465,719				14,004,501			3,461,218	

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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 and 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 and 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: Electric R, D and D Performed Internally: Generation hydroelectric Recreation fish and wildlife Other hydroelectric Fossil-fuel steam Internal combustion or gas turbine Nuclear Solar Wind Other renewable Unconventional generation Siting and heat rejection Transmission Overhead Underground Distribution Regional Transmission and Market Operation Energy Storage Environment (other than equipment) Other (Classify and include items in excess of \$50,000.) Total Cost Incurred Electric, R, D and D Performed Externally: Research Support to the electrical Research Council or the Electric Power Research Institute Research Support to Edison Electric Institute Research Support to Nuclear Power Groups Research Support to Others (Classify) Total Cost Incurred 3. Include in column (c) all R, D and 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 and 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 and 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 and 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.							
Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	B(1)	Electric Power Research Institute		465,859	930.2	465,859	
2	B(4)	Other, 2 items under \$50,000		23,436	930.2	23,436	
3				9,188	566	9,188	
4				7,208	588	7,208	
5	B(5)	Total		505,691		505,691	

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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	193,123,356			
4	Transmission	14,746,321			
5	Regional Market	463,226			
5.1	Energy Storage				
6	Distribution	36,390,191			
7	Customer Accounts	15,664,321			
8	Customer Service and Informational	1,375,975			
9	Sales	1,755,311			
10	Administrative and General	108,380,577			
11	TOTAL Operation (Enter Total of lines 3 thru 10)	371,899,278			
12	Maintenance				
13	Production	71,571,605			
14	Transmission	3,011,781			
15	Regional Market				
15.1	Energy Storage				
16	Distribution	26,312,874			
17	Administrative and General	5,270,615			
18	TOTAL Maintenance (Total of lines 13 thru 17)	106,166,875			
19	Total Operation and Maintenance				
20	Production (Enter Total of lines 3 and 13)	264,694,961			
21	Transmission (Enter Total of lines 4 and 14)	17,758,102			
22	Regional Market (Enter Total of Lines 5 and 15)	463,226			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)				
23	Distribution (Enter Total of lines 6 and 16)	62,703,065			
24	Customer Accounts (Transcribe from line 7)	15,664,321			
25	Customer Service and Informational (Transcribe from line 8)	1,375,975			
26	Sales (Transcribe from line 9)	1,755,311			
27	Administrative and General (Enter Total of lines 10 and 17)	113,651,192			
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	478,066,153	8,027,155	486,093,308	
29	Gas				
30	Operation				

31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	197,111		
34	Storage, LNG Terminaling and Processing	2,061,988		
35	Transmission	890,475		
36	Distribution	20,423,765		
37	Customer Accounts	3,899,017		
38	Customer Service and Informational	1,013,140		
39	Sales			
40	Administrative and General	10,221,302		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	38,706,798		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	2,311,720		
47	Transmission	270,904		
48	Distribution	8,301,419		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	10,884,043		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	197,111		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	4,373,708		
56	Transmission (Lines 35 and 47)	1,161,379		
57	Distribution (Lines 36 and 48)	28,725,184		
58	Customer Accounts (Line 37)	3,899,017		
59	Customer Service and Informational (Line 38)	1,013,140		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	10,221,302		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	49,590,841	1,425,850	51,016,691
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	527,656,994	9,453,005	537,109,999
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	238,501,235	66,975,417	305,476,652
69	Gas Plant	25,442,716	11,347,921	36,790,637
70	Other (provide details in footnote):	(a) 1,048,112		1,048,112

71	TOTAL Construction (Total of lines 68 thru 70)	264,992,063	78,323,338	343,315,401
72	Plant Removal (By Utility Departments)			
73	Electric Plant	16,940,165	4,412,818	21,352,983
74	Gas Plant	519,402	747,682	1,267,084
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	17,459,567	5,160,500	22,620,067
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Other Accounts Receivable (Acct No. 143)	213		213
80	Merchandise (Acct No. 155)		65,573	65,573
81	Prepayments (Acct No. 165)		35,902	35,902
82	Regulatory Assets (Acct No. 182.3)	12,553,304	268,345	12,821,649
83	Preliminary Survey and Investigation (Acct No. 183)	311,034		311,034
84	Miscellaneous Deferred Debits (Acct No. 186)	3,097	15,105	18,202
85	Miscellaneous Deferred Credits (Acct No. 253)	171,630	1,239	172,869
86	Regulatory Liabilities (Acct No. 254)	369,086	5,458	374,544
87	Non-utility (Accts No. 416-417.1)	113,131	1,265	114,396
88	Miscellaneous Income and Deductions (Accts No. 426.1-426.5)	561,413	4,092	565,505
89	Non-utility CWP and RWP	429,448	11,433	440,881
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	14,512,356	408,412	14,920,768
96	TOTAL SALARIES AND WAGES	824,620,980	93,345,255	917,966,235

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: SalariesAndWagesUtilityPlantConstructionOther			
E120.1 Nuclear fuel in process of refinement, conversion, enrichment and fabrication			

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4	
COMMON UTILITY PLANT AND EXPENSES				
1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric 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 the order of the Commission or other authorization.				
Instruction 1:				
Account	Electric	Allocated to Utility Departments Gas	Cost at Dec. 31, 2025	
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED (ACCOUNTS 101 AND 106)				
301	Organization	91,217	9,391	100,608
303	Computer Software	756,408,288	77,874,454	834,282,742
Total intangible plant		756,499,505	77,883,845	834,383,350
389	Land and land rights	14,777,464	1,175,338	15,952,802
390	Structures and improvements	354,577,498	28,201,636	382,779,134
391	Office furniture and equipment	259,603,711	20,647,810	280,251,521
392	Transportation equipment	12,758,982	2,356,769	15,115,751
393	Stores equipment	228,026	18,136	246,162
394	Tools/shop/garage equipment	25,110,978	2,003,726	27,114,704
395	Laboratory equipment	—	—	—
396	Power operated equipment	2,440,174	303,980	2,744,154
397	Communications equipment	942,740	74,981	1,017,721
398	Miscellaneous equipment	15,145	1,204	16,349
399.1	Asset retirement costs for general plant	316,834	25,200	342,034
Total		1,427,271,057	132,692,625	1,559,963,682
COMMON UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)				
	General Plant	15,196,131	1,545,241	16,741,372

COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS (ACCOUNT 107)							
	General Plant			279,607,432		24,507,145	304,114,577
Instruction 2:							
COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION (ACCOUNT 108 AND 111)							
	General Plant			600,500,314		58,457,139	658,957,453
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.							
				Cost of Removal Reserve			
	Common General			\$	4,592,376		
	Common Intangible				—		
	Total Common				4,592,376		
Instruction 3:							
		Common Utility Plant Expenses					
					Electric	Gas	Total
403	Depreciation Expense				51,855,745	3,896,791	55,752,536
403.1	Depreciation Expense - ARC				3,467	272	3,739
404	Amortization of limited term plant				85,641,115	8,947,028	94,588,143
405	Amortization of other plant				(4,412)	(332)	(4,744)
407.4	Amortization of regulatory credits				(25,403)	(1,996)	(27,399)
411.1	Accretion expense				21,937	1,725	23,662
Total					137,492,449	12,843,488	150,335,937
Basis of Allocation of Common Utility 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.							

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS							
1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchase 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)						
2.1	Net Purchases (Account 555.1)						
3	Net Sales (Account 447)						
4	Transmission Rights						
5	Ancillary Services						
6	Other Items (list separately)						
7	Midcontinent Ind Sys Operator (MISO)						
8	MISO - Net Purchases (Account 555)	21,771,879	90,442,231	135,088,973	172,680,241		
9	MISO - Net Sales (Account 447)	(54,094,772)	(109,014,840)	(146,342,270)	(69,019,302)		
10	MISO - Transmission Rights	(10,501,221)	(22,865,503)	(47,446,441)	(118,776,133)		
11	MISO - Ancillary Services	1,955,772	3,619,577	8,939,249	10,660,786		
12	MISO - Uplift Charges	(1,732,953)	1,055,281	353,296	3,967,031		
13	Electric Reliability Council of TX (ERCOT)						
14	ERCOT - Net Purchases (Account 555)	836,602	1,950,327	4,177,371	5,162,118		
15	ERCOT - Net Sales (Account 447)	(514,495)	(835,075)	(1,697,248)	(2,642,302)		
16	ERCOT - Transmission Rights						
17	ERCOT - Ancillary Services						
18	ERCOT - Uplift Charges	4,342	(620)	4,334	6,458		
19	PJM Interconnection						
20	PJM - Net Purchases (Account 555)						
21	PJM - Net Sales (Account 447)	(1,972,622)	(8,075,256)	(12,102,453)	(19,782,420)		
22	PJM - Transmission Rights		115,285	181,929	280,531		
23	PJM - Ancillary Services						
24	PJM - Uplift Charges	267	267	267	5,628		
25	Southwest Power Pool (SPP)						
26	SPP - Net Purchases (Account 555)	33,147	60,697	106,105	158,908		
27	SPP - Net Sales (Account 447)						
28	SPP - Transmission Rights						
29	SPP - Ancillary Services	616	1,134	1,570	2,237		
30	SPP - Uplift Charges	2,471	5,026	6,944	9,278		
46	TOTAL	(44,210,967)	(43,541,469)	(58,728,374)	(17,286,941)		

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4		
PURCHASES AND SALES OF ANCILLARY SERVICES							
Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff. In columns for usage, report usage-related billing determinant and the unit of measure. 1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year. 2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year. 3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year. 4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year. 5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period. 6. On Line 7 columns (b), (c), (d), and (e) 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		
Line No.	Type of Ancillary Service (a)	Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	0	0	11,366,630	0	0	879,942
2	Reactive Supply and Voltage	0	0	11	0	0	128,989
3	Regulation and Frequency Response	0	0	3,384,217	0	0	8,019,780
4	Energy Imbalance	0	0		0	0	
5	Operating Reserve - Spinning	0	0	2,015,457	0	0	1,688,658
6	Operating Reserve - Supplement	0	0	552,773	0	0	171,421
7	Other	0	0	9,336,085	0	0	4,185,547
8	Total (Lines 1 thru 7)			26,655,173			15,074,337

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: AncillaryServicesPurchasedNumberOfUnits			
Number of units is not available			
(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower			
Unit of measure is not available			
(c) Concept: AncillaryServicesSoldNumberOfUnits			
Volume of units is not available			
(d) Concept: AncillaryServicesSoldUnitsOfMeasure			
Unit of measure is not available			
(e) Concept: AncillaryServicesPurchasedNumberOfUnits			
Number of units is not available			
(f) Concept: AncillaryServicesPurchasedNumberOfUnitsPower			
Unit of measure is not available			
(g) Concept: AncillaryServicesSoldNumberOfUnits			
Volume of units is not available			
(h) Concept: AncillaryServicesSoldUnitsOfMeasure			
Unit of measure is not available			
(i) Concept: AncillaryServicesPurchasedNumberOfUnits			
Number of units is not available			
(j) Concept: AncillaryServicesPurchasedNumberOfUnitsPower			
Unit of measure is not available			
(k) Concept: AncillaryServicesSoldNumberOfUnits			
Volume of units is not available			
(l) Concept: AncillaryServicesSoldUnitsOfMeasure			
Unit of measure is not available			
(m) Concept: AncillaryServicesPurchasedNumberOfUnits			
Number of units is not available			
(n) Concept: AncillaryServicesPurchasedNumberOfUnitsPower			
Unit of measure is not available			
(o) Concept: AncillaryServicesSoldNumberOfUnits			
Volume of units is not available			
(p) Concept: AncillaryServicesSoldUnitsOfMeasure			
Unit of measure is not available			
(q) Concept: AncillaryServicesPurchasedNumberOfUnits			
Number of units is not available			
(r) Concept: AncillaryServicesPurchasedNumberOfUnitsPower			

Unit of measure is not available		
(s) Concept: AncillaryServicesSoldNumberOfUnits		
Volume of units is not available		
(t) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(u) Concept: AncillaryServicesPurchasedNumberOfUnits		
Number of units is not available		
(v) Concept: AncillaryServicesPurchasedNumberOfUnitsPower		
Unit of measure is not available		
(w) Concept: AncillaryServicesPurchasedAmount		
NSPP Real-Time Short-Term Reserve Cost Distribution Amount	\$	9,336,085
(x) Concept: AncillaryServicesSoldNumberOfUnits		
Volume of units is not available		
(y) Concept: AncillaryServicesSoldUnitsOfMeasure		
Unit of measure is not available		
(z) Concept: AncillaryServicesSoldAmount		
NSPP Real-Time Ramp Capability Amount	\$	63,508
NSPP Day-Ahead Ramp Capability Amount	\$	246,496
NSPP Day-Ahead Short-Term Reserve Amount	\$	3,878,949
NSPP Real-Time Short-Term Reserve Amount	\$	(3,406)
	\$	4,185,547

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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.										
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)
	NAME OF SYSTEM: Northern States Power Co. Integrated System									
1	January	7,680	20	18	6,323	1,678				
2	February	7,373	17	19	6,030	1,627				
3	March	6,420	19	14	5,265	1,394				
4	Total for Quarter 1				17,618	4,699	0			0
5	April	6,267	2	13	5,126	1,359				
6	May	8,243	14	18	6,807	1,746				
7	June	9,714	22	18	7,852	2,055				
8	Total for Quarter 2				19,785	5,160	0			0
9	July	10,136	15	17	8,322	2,117				
10	August	9,494	7	17	7,629	2,088				
11	September	9,285	16	17	7,554	2,003				
12	Total for Quarter 3				23,505	6,208	0			0
13	October	8,436	3	17	6,816	1,829				
14	November	6,499	26	12	5,249	1,470				
15	December	7,376	19	18	5,994	1,676				
16	Total for Quarter 4				18,059	4,975	0			0
17	Total				78,967	21,042	0	0	0	0

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

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.

(b) Concept: FirmNetworkServiceForSelf

"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			339
February			302
March			253
April			233
May			327
June			213
July			324
August			242
September			292
October			228
November			233
December			310
Total			3,296

"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			63
February			62
March			53
April			47
May			43
June			57
July			63
August			69
September			58
October			60
November			54
December			55
Total			684

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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).										
Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import 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)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 2026-04-09		Year/Period of Report End of: 2025/ 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)	32,715,709			
3	Steam	5,951,069	23	Requirements Sales for Resale (See instruction 4, page 311.)	6,284,787			
4	Nuclear	13,226,335	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	11,853,880			
5	Hydro-Conventional	46,815	25	Energy Furnished Without Charge	214			
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	50,782			
6.1	Solar	613,181	27	Total Energy Losses	244,212			
6.2	Wind	9,042,162	27.1	Total Energy Stored				
6.3	Other Renewable	238,358	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	51,149,584			
7	Other	4,968,497						
8	Less Energy for Pumping							
9	Net Generation (Enter Total of lines 3 through 8)	34,086,417						
10	Purchases (other than for Energy Storage)	17,063,166						
10.1	Purchases for Energy Storage	0						
11	Power Exchanges:							
12	Received	0						
13	Delivered	0						
14	Net Exchanges (Line 12 minus line 13)	0						
15	Transmission For Other (Wheeling)							
16	Received							
17	Delivered							
18	Net Transmission for Other (Line 16 minus line 17)	0						
19	Transmission By Others Losses							
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	51,149,583						

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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).							
Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)	
	NAME OF SYSTEM: Northern States Power Co. Integrated System						
29	January	4,988,156	1,458,138	5,443	20	18	
30	February	4,309,089	1,283,426	5,152	17	19	
31	March	4,573,973	1,541,406	4,561	4	18	
32	April	3,999,129	1,212,254	4,389	2	13	
33	May	3,679,959	665,644	6,016	14	18	
34	June	4,095,959	729,103	6,937	22	18	
35	July	5,014,822	998,603	7,205	15	17	
36	August	4,767,490	982,923	6,806	7	17	
37	September	3,817,551	588,083	6,649	16	17	
38	October	3,946,133	666,257	6,084	3	17	
39	November	3,690,139	664,853	4,510	17	18	
40	December	4,267,184	1,063,190	5,089	19	18	
41	Total	51,149,584	11,853,880				

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: EnergyActivity									
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
	20-Jan	1800	6,525	4,666	399	378	1,059		24
	17-Feb	1900	6,270	4,402	383	367	1,091		26
	4-Mar	1800	5,461	3,952	307	302	883		18
	2-Apr	1300	5,312	3,823	280	286	904		19
	14-May	1800	6,988	5,227	351	438	955		17
	22-Jun	1800	8,152	6,095	330	512	1,195		20
	15-Jul	1700	8,446	6,421	274	510	1,222		19
	7-Aug	1700	8,008	5,930	404	472	1,181		20
	16-Sep	1700	7,807	5,801	358	490	1,137		21
	3-Oct	1700	7,140	5,278	355	451	1,036		19
	17-Nov	1800	5,479	3,944	281	285	950		19
	19-Dec	1800	6,173	4,431	335	323	1,062		23

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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Steam Electric Generating Plant Statistics

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 Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA 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.

Line No.	Item (a)	Plant Name: A S King	Plant Name: Angus Anson	Plant Name: Black Dog 2, 5, & 6	Plant Name: Blue Lake	Plant Name: High Bridge 7,8,9	Plant Name: Inver Hills	Plant Name: Monticello	Plant Name: Prairie Island	Plant Name: Riverside	Plant Name: Sherburne County
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Gas Turbine	CC / Gas Turb ^(a)	Gas Turbine	Combined Cycle	Gas Turbine	Nuclear ^(b)	Nuclear ^(c)	Combined Cycle	Steam ^(d)
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional	Ind Enclosures	Conventional	Ind Enclosures	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1968	1994	1987	1974	1924	1972	1971	1973	1911	1976
4	Year Last Unit was Installed	1968	2005	2018	2005	2008	1972	1971	1974	2009	1987
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	598.40	405.70	554.30	559.30	644.10	280.50	685.00	1,186.20	585.90	1,319.10
6	Net Peak Demand on Plant - MW (60 minutes)	516	357	526	330	628	267	663	1,118	510	1,258
7	Plant Hours Connected to Load	2,111	1,477	7,018	1,878	6,486	1,426	7,491	8,760	981	8,260
8	Net Continuous Plant Capability (Megawatts)	511	401	523	545	580	357	646	1,092	502	1,197
9	When Not Limited by Condenser Water	511	401	523	545	580	357	646	1,092	500	1,197
10	When Limited by Condenser Water	511	343	491	454	530	272	617	1,040	454	1,197
11	Average Number of Employees	70	7	24	5	26	7	328	448	24	212
12	Net Generation, Exclusive of Plant Use - kWh	890,433,000	236,480,994	853,676,000	439,460,420	2,979,959,000	129,990,000	4,676,575,000	8,549,760,000	328,931,000	5,060,636,000
13	Cost of Plant: Land and Land Rights	1,335,100	9,388,366	952,692	141,878	523,582	351,801	778,651	892,327	450,133	14,078,025
14	Structures and Improvements	42,096,260	8,700,065	58,970,864	2,362,645	71,970,752	1,913,160	323,534,682	359,958,586	59,749,670	241,335,474
15	Equipment Costs	680,361,666	150,134,148	320,505,006	198,278,020	383,861,340	65,677,444	1,438,001,189	2,297,194,594	280,621,290	1,101,005,779
16	Asset Retirement Costs	5,502,624	412,520	48,896,030	170,055	20,138	26,851	59,466,115	(177,153,829)	1,060,163	14,372,265
17	Total Cost (10-23)	729,295,649	168,635,099	429,324,591	200,952,598	456,375,812	67,969,256	1,821,780,637	2,480,891,678	341,881,255	1,370,791,543
18	Cost per KW of Installed Capacity (line 17/5) Including	1,218.7427	415.6645	774.5347	359.2930	708.5481	242.3146	2,659.5338	2,091.4615	583.5147	1,039.1870
19	Production Expenses: Oper, Supv, & Engr	943,678	241,083	1,018,552	246,759	785,887	185,602	16,415,293	21,807,149	795,764	1,718,293
20	Fuel	29,716,081	7,600,736	33,829,660	17,428,270	82,651,763	9,117,249	38,788,974	75,709,568	19,295,715	142,293,633
21	Coolants and Water (Nuclear Plants Only)							3,874,278	6,397,733		
22	Steam Expenses	4,318,972						25,976,024	39,254,928		7,643,053
23	Steam From Other Sources										
24	Steam Transferred (Cr)										
25	Electric Expenses	924,187	239,476	2,009,632	462,988	2,039,041	309,493	261,811	2,815,725	2,310,786	4,058,146
26	Misc Steam (or Nuclear) Power Expenses	3,262,182	573,105	1,969,470	246,337	1,975,491	180,954	53,777,778	83,870,758	1,742,771	6,463,661

27	Rents	412,122	112,497	485,923	104,280	375,825	76,000	2,868,374	4,813,223	371,032	967,840							
28	Allowances																	
29	Maintenance Supervision and Engineering	426,090	178,040	414,998	96,814	320,201	83,609	3,213,173	4,176,499	316,877	868,632							
30	Maintenance of Structures	638,337	344,608	1,556,969	848,851	695,492	55,734			1,098,434	2,949,788							
31	Maintenance of Boiler (or reactor) Plant	3,410,350						9,102,115	16,125,207		8,642,490							
32	Maintenance of Electric Plant	1,137,442	933,654	3,811,209	396,648	2,405,705	513,417	6,122,147	15,684,172	1,917,861	1,999,764							
33	Maintenance of Misc Steam (or Nuclear) Plant	1,202,806	17,239	135,226	44,216	199,817	378,492	17,330,186	30,181,698	152,589	3,851,125							
34	Total Production Expenses	46,392,247	10,240,438	45,231,639	19,875,163	91,449,222	10,900,550	177,730,153	300,836,660	28,001,829	181,456,425							
35	Expenses per Net kWh	0.0521	0.0433	0.0530	0.0452	0.0307	0.0839	0.0380	0.0352	0.0851	0.0359							
35	Plant Name	A S King	A S King	A S King	Angus Anson	Angus Anson	Black Dog 2, 5, & 6	Blue Lake	Blue Lake	High Bridge 7,8,9	Inver Hills	Inver Hills	Monticello	Prairie Island	Riverside	Riverside	Sherburne County	Sherburne County
36	Fuel Kind	Coal	Gas	Oil	Gas	Oil	Gas	Gas	Oil	Gas	Gas	Oil	Nuclear	Nuclear	Gas	Oil	Coal	Oil
37	Fuel Unit	T	Mcf	bbl	Mcf	bbl	Mcf	Mcf	bbl	Mcf	Mcf	bbl	g	g	Mcf	bbl	T	bbl
38	Quantity (Units) of Fuel Burned	536,097	71,930	38	2,859,394	95	8,031,512	4,663,227	1,298	20,560,421	1,953,257	4,171	447,761	847,431	2,571,565	14	3,026,360	13,672
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	10,639	967	146,654	1,016	113,472	981	1,031	146,757	1,035	1,033	139,263	110,381	106,841	1,005	152,184	10,305	137,745
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.866	7.613	106.882	3.398	94	4.091	3.700	111.853	3.953	4.300	168.612			7.490	69.557	42.308	104.219
41	Average Cost of Fuel per Unit Burned	52.756	7.613	106.882	3.398	94	4.091	3.700	111.853	3.953	4.300	168.612			7.490	69.557	45.268	104.219
42	Average Cost of Fuel Burned per Million BTU	2.479	7.868	17.353	3.344	20	4.171	3.590	18.147	3.819	4.164	28.827	0.787	0.839	7.451	10.882	2.196	18.014
43	Average Cost of Fuel Burned per kWh Net Gen		0.032				0.038		0.038	0.026	0.046		0.010	0.009	0.060			0.027
44	Average BTU per kWh Net Generation		12,666.31			13,134	9,218.41		10,392.70	6,784.23	10,375.19		10,513.89	10,412.67	8,086			12,341.00

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: PlantKind			
Black Dog Unit 2 & 5 are combined cycle plants. Black Dog Unit 6 is a gas turbine.			
(b) Concept: PlantKind			
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 85 metric tons of uranium with a nominal U-235 enrichment of 4.1 weight percent in the fresh fuel. The reactor is licensed to operate at 2,004 MWt.			
(c) Concept: PlantKind			
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 48 metric tons of uranium with a nominal U-235 enrichment of 4.91 weight percent in the fresh fuel. The reactor is licensed to operate at 1677 MWt.			
(d) Concept: PlantKind			
Sherburne County Generating Plant Unit 3 is jointly owned by NSP-Minnesota (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). See Note 3 of the Financial Statements on Page 123 for disclosures regarding Sherco Unit 3. Sherburne County Generating Plant Unit 2 retired Dec. 31, 2023.			
(e) Concept: FuelBurnedAverageHeatContent			
The Coal BTU numbers for the AS King and Sherburne plant are estimates			
(f) Concept: FuelBurnedAverageHeatContent			
The "Average Heat Content of Fuel Burned" is calculated as: Coal: Btu/pound Oil: BTU/gallons Gas: Btu/cubic ft			
(g) Concept: FuelBurnedAverageHeatContent			
The Coal BTU numbers for the AS King and Sherburne plant are estimates			
(h) Concept: AverageCostOfFuelBurnedPerMillionBritishThermalUnit			
The Coal BTU numbers for the AS King and Sherburne plant are estimates			
(i) Concept: AverageCostOfFuelBurnedPerMillionBritishThermalUnit			
The Coal BTU numbers for the AS King and Sherburne plant are estimates			

Name of Respondent: Northern States Power Company (Minnesota)										This report is: (1) ☒ An Original (2) ☐ A Resubmission					Date of Report: 04/09/2026			Year/Period of Report End of: 2025/ Q4					
Renewable Generating Plant Statistics																							
1. Report data for plant in Service only. 2. Report in this page renewable plants of 10,000 Kw or more. 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. 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.																							
Line No.	Item (a)	Plant Name: 0	Plant Name: Ben Fowke Wind Energy Center	Plant Name: Blazing Star Wind 1	Plant Name: Blazing Star Wind 2	Plant Name: Borders Wind	Plant Name: Community Wind North	Plant Name: Courtenay Wind	Plant Name: Crowned Ridge	Plant Name: Dakota Range 1 & 2	Plant Name: Foxtail Wind	Plant Name: Freeborn	Plant Name: Jeffers	Plant Name: Lake Benton Wind	Plant Name: Mower County	Plant Name: Nobles Wind	Plant Name: Northern Wind CV	Plant Name: Pleasant Valley Wind	Plant Name: Red Wing	Plant Name: Rock Aetna	Plant Name: Sherco Solar 1	Plant Name: Sherco Solar 2	Plant Name: Wilmarth
1	Kind of Plant (Solar, Wind, Biomass, etc.)		Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	Wind	RDF	Wind	Solar	Solar	RDF
2	Type of Constr (PV Tracking, Offshore, Boiler, etc)		Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Onshore	Steam	Onshore	Tracking	Tracking	Steam
3	Year Originally Constructed		2008	2020	2020	2015	2020	2016	2020	2022	2019	2021	2020	2019	2020	2010	2023	2015	1949	2022	2024	2025	1948
4	Year Last Unit was Installed		2023	2020	2020	2025	2020	2016	2020	2022	2019	2021	2020	2019	2020	2022	2023	2025	1949	2022	2024	2025	1951
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		107.50	218.00	218.00	165.00	26.40	200.00	200.60	304.00	163.60	218.00	44.00	100.20	98.90	212.80	100.20	220.00	23.00	21.60	264.60	281.40	25.00
6	Net Peak Demand on Plant - MW (60 minutes)		98	200	200	143	26	193	196	290	151	199	44	101	91	199	91	184	23	20	223	237	24
7	Plant Hours Connected to Load		7,993	8,194	8,221	6,492	8,238	7,448	8,240	8,211	8,114	8,206	8,001	8,291	8,070	8,119	8,223	6,533	7,706	8,115	4,101	3,120	7,414
8	Net Continuous Plant Capability (Megawatts)		100	200	200	150	26	190	192	298	150	200	43	99	91	200	92	200	18	20	223	237	18
9	Net Generation, Exclusive of Plant Use - KWh		375,759,615	872,935,989	881,756,347	384,898,273	110,318,531	424,361,802	865,884,489	1,018,280,772	623,225,829	785,247,929	196,466,157	440,363,731	333,214,093	823,448,094	358,042,484	463,695,226	139,346,000	84,263,126	414,640,024	198,541,083	99,012,000
10	Cost of Plant: Land and Land Rights		10,672,452	633,701	239,814		5,420	2,085,661	422,100	53,129	177,364	684,885	40,442	10,337,215	698,578	3,884,834			755,399		3,635,971	16,719	499,773
11	Structures and Improvements		12,179,498	22,800,119	26,572,211	32,400,712	2,712,147	7,621,664	21,008,188	353,187,074	32,656,437	54,185,756	3,717,258	37,707,863	11,872,559	13,556,122		9,875,174	15,591,612		6,692,585	6,999,163	13,547,869
12	Solar Panels, Wind Turbines and Generators		112,889,487	278,170,375	308,263,646	290,644,748	26,675,080	265,447,542	286,792,261	35,829,603	207,316,496	244,407,938	38,763,501	119,796,963	195,321,067	221,083,412	164,778,835	366,408,621	10,987,079	32,236,732	276,762,976	257,576,936	14,281,384
13	Fuel Holders																		6,492,454				7,321,355
14	Boilers																		51,551,772				48,325,489
15	Collector System		554,140	10,276,174	4,961,278	338,362	1,277,890	9,591,089	11,552,563	11,444,118		11,649,357	487,141	7,650,226	2,274,806	19,675,129	1,150,656	6,082,658		75,819	46,736	25,663,284	
16	Generator Step-up Transformers (GSU)																	622,868			26,955	9,433,061	

17	Inverters																				55,674,407	29,886,878	
18	Other Accessory Electrical Equipment		7,490,981	340,603	3,335,530	763,755	217,623	1,801,217	414,809	4,061,948	4,629,385	3,046,072	23,790	322,679	218,442	14,626,217	14,480,139	21,549	5,440,097	2,217,480	2,683	2,431,701	2,631,452
19	Computer Hardware																						
20	Computer Software																				1,028,897	1,091,871	
21	Communication Equipment					2,177,649		2,059,711									10,262,356	1,408,120		344,630			
22	Miscellaneous Power Plant Equipment				1,888,182		81,546	36,482	80,774	501,703		13,698,261	189,833			65,295			972,710		3,120,745	5,085,986	721,794
23	Asset Retirement Costs		6,926,293	35,794,662	38,866,926	11,538,159	5,741,613	18,329,666	33,088,153	20,045,831	8,205,762	33,780,078	9,119,820	7,912,467	15,109,988	24,502,176	7,694,118	23,337,033	1,330,835	1,750,048	6,816,208	6,626,197	1,325,991
24	Total Cost (10- 23)		150,712,851	348,015,634	384,127,587	337,863,385	36,711,319	306,973,032	353,358,848	425,123,406	252,985,444	361,452,347	52,341,785	183,727,413	225,495,440	297,393,185	198,366,104	407,756,023	93,121,958	36,624,709	353,808,163	344,811,796	88,655,107
25	Cost per KW of Installed Capacity (line 24/5) Including		1,401.9800	1,596.4020	1,762.0532	2,047.6569	1,390.5803	1,534.8652	1,761.5097	1,398.4323	1,546.3658	1,658.0383	1,189.5860	1,833.6069	2,280.0348	1,397.5244	1,979.7016	1,853.4365	4,048.78	1,695.5884	1,337.1435	1,225.3440	3,546.2043
26	Production Expenses: Oper, Supv, & Engr		167,590	162,883	138,362	100		73,714	168,984	130,077	149,397	176,244	3,149	86,979	163,957	239,294		75,515	25,883		53,063	7,395	158,576
27	Generation and Other Plant Operating Expenses		591,281	1,399,980	1,379,104	817,630	220,748	1,477,658	834,909	591,868	(133,721)	1,518,939	364,771	408,997	1,520,428	1,618,556	550,754	1,164,414	2,008,165	152,022	473,034	134,452	2,845,319
28	Fuel																		3,492,181				3,657,693
29	Steam Expenses																						
30	Electric Expenses																						
31	Misc Steam Power Expenses																						
32	Rents		839,728	1,627,676	1,759,840	407,124	183,026	1,423,517	926,201	1,908,162	741,520	2,966,182	296,512	531,029	706,884	1,170,175	539,509	1,163,133	165,089	148,918	1,502,601	346	160,434
33	Environmental Credits																						
34	Maintenance Supervision and Engineering					82,919		67	1,957	23,545	55			55				42	194,297		30,415	6,898	1,239
35	Maintenance of Structures and Equipment		140,644	205,579	213,044	115,803	5,287	43,268	646,898	351,160	309,817	341,478	27,220	209,539	396,177	550,727	66,298	122,029	397,988	18,300	515,069		245,683
36	Maintenance of Boiler Plant																		1,520,415				934,117
37	Maintenance of Electric Plant																		103,666				454,152
38	Maintenance of Computer Hardware		0		0	0	0	0		0	0	0	0	0	0	236				0	4,100	0	36,233
39	Maintenance of Computer Software																						

40	Maintenance of Communication Equipment		0		50	0	0	681		2,178	0	0	21,432	0	0	1			1,823	0	2,368	747	2,491
41	Maintenance of Misc Plant		852,821	1,295,806	1,302,932	743,739	202,159	1,319,185	1,080,828	424,676	(150,675)	1,383,759	336,653	571,291	62,782	1,042,505	576,033	446,339	689,096	159,000	432,854	133,534	523,737
42	Total Production Expenses		2,592,064	4,691,924	4,793,332	2,167,315	611,220	4,338,090	3,659,777	3,431,666	916,393	6,386,602	1,049,737	1,807,890	2,850,228	4,621,494	1,732,594	2,971,472	8,598,603	478,240	3,013,504	283,372	9,019,674
43	Expenses per Net KWh		0.0069	0.0054	0.0054	0.0056	0.0055	0.0102	0.0042	0.0034	0.0015	0.0081	0.0053	0.0041	0.0086	0.0056	0.0048	0.0064	0.0617	0.0057	0.0073	0.0014	0.0911

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
Hydroelectric Generating Plant Statistics							
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. 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.							
Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0		FERC Licensed Project No. 0 Plant Name: Henn Is & Upper Dam			
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)			13.90			
6	Net Peak Demand on Plant-Megawatts (60 minutes)			10			
7	Plant Hours Connect to Load			8,539			
8	Net Plant Capability (in megawatts)						
9	(a) Under Most Favorable Oper Conditions			7			
10	(b) Under the Most Adverse Oper Conditions			6			
11	Average Number of Employees			2			
12	Net Generation, Exclusive of Plant Use - kWh			46,815,369			
13	Cost of Plant						
14	Land and Land Rights			1,548,707			
15	Structures and Improvements			1,701,921			
16	Reservoirs, Dams, and Waterways			26,037,166			
17	Equipment Costs			3,417,909			
18	Roads, Railroads, and Bridges			369,302			
19	Asset Retirement Costs						
20	Total Cost (10-23)			33,075,005			
21	Cost per KW of Installed Capacity (line 20 / 5)			2,379.497			
22	Production Expenses						
23	Operation Supervision and Engineering			27,437			
24	Water for Power			65,717			
25	Hydraulic Expenses			259,251			
26	Electric Expenses			12,822			
27	Misc Hydraulic Power Generation Expenses			122,516			
28	Rents			36,924			
29	Maintenance Supervision and Engineering			44			
30	Maintenance of Structures			35,817			

31	Maintenance of Reservoirs, Dams, and Waterways		94,330
32	Maintenance of Electric Plant		271,709
33	Maintenance of Misc Hydraulic Plant		1,511
34	Total Production Expenses (total 23 thru 33)		928,078
35	Expenses per net kWh		0.0198

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
Pumped Storage Generating Plant Statistics				
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 that 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." 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.				
Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0		
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)	0		
6	Plant Hours Connect to Load While Generating	0		
7	Net Plant Capability (in megawatts)	0		
8	Average Number of Employees			
9	Generation, Exclusive of Plant Use - kWh	0		
10	Energy Used for Pumping			
11	Net Output for Load (line 9 - line 10) - Kwh	0		
12	Cost of Plant			
13	Land and Land Rights			
14	Structures and Improvements	0		
15	Reservoirs, Dams, and Waterways	0		
16	Water Wheels, Turbines, and Generators	0		
17	Accessory Electric Equipment	0		
18	Miscellaneous Powerplant Equipment	0		
19	Roads, Railroads, and Bridges	0		
20	Asset Retirement Costs	0		
21	Total Cost (10-23)			
22	Cost per KW of installed cap (line 21 / 4)			
23	Production Expenses			
24	Operation Supervision and Engineering	0		
25	Water for Power	0		
26	Pumped Storage Expenses	0		
27	Electric Expenses	0		
28	Misc Pumped Storage Power generation Expenses	0		
29	Rents	0		

30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
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)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

[illegible]

29													
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34												
35	TOTAL		0	0	0	0	0	0	0	0		0

Name of Respondent: Northern States Power Company (Minnesota)			This report is: (1) ☒ An Original (2) ☐ A Resubmission		Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ Q4	
ENERGY STORAGE OPERATIONS (Small Plants)								
1. Small Plants are plants less than 10,000 Kw. 2. In columns (a) and (b) report the name of the energy storage project, and location. 3. In column (c), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project. 4. In column (d), report operation expenses excluding fuel, (e), maintenance expenses, (f) fuel costs for storage operations and (g) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. 5. If any other expenses, report in column (h) and footnote the nature of the item(s).								
Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses				
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
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29								
30								
31								
32								
33								
34								
35								
36	TOTAL							

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.

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

4. 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.

5. 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.

6. 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).

7. 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.

8. 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.

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

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	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			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	(5703;01) CHISAGO CO.	FORBES	500.0	500.0	TOWER	61.450	0.000	1	9-1192 ACSR	2,237,403	16,180,329	18,417,732				
2	(5702;01) FORBES	REIL (MN)	500.0	500.0	TOWER	203.628	0.000	1	9-1192.5 ACSR	3,087,573	86,638,588	89,726,161				
3	(5654;01) HAMPTON	HELENA	345.0	345.0	3 POLE	1.317	0.000	1	3-397.5 ZTACSR-VR2							
4	(5654;01) HAMPTON	HELENA	345.0	345.0	SINGLE POLE	37.689	0.000		3-397.5 ZTACSR-VR2		28,957,664	28,957,664				
5	(5653;01) LYON CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	5.681	34.682	1	6-397.5 ZTACSR-VR2		24,643,197	24,643,197				
6	(5653-SD;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	7.250	2.942	1	6-397.5 ZTACSR-VR2		4,059,063	4,059,063				
7	(5653-MN;01) BROOKINGS CO.	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	4.037	4.825	1	6-397.5 ZTACSR-VR2		5,531,171	5,531,171				
8	(5652;01) SHERBURNE CO.	SHERCO SOLAR EAST	345.0	345.0	SINGLE POLE	2.040	0.000	1	3-556.5 KMCIL ACSR/VR2		8,374,512	8,374,512				
9	(5651;01) SHERBURNE CO.	SHERCO SOLAR WEST	345.0	345.0	SINGLE POLE	3.708	0.000	1	3-556.5 ACSR/VR2		14,584,083	14,584,083				
10	(5650;01) DAKOTA RANGE WIND	TWIN BROOKS SW. ST.	345.0	345.0	SINGLE POLE	0.091	0.000	1	6-795 ACSR							
11	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.000	4.432	1	6-954 ACSS							
12	(0998;01) SIOUX CITY (WAPA)	SPLIT ROCK	345.0	345.0	SINGLE POLE	0.049	0.580		6-954 ACSS/TW		670,200	670,200				
13	(0997;01) SPLIT ROCK	WHITE (WAPA)	345.0	345.0	SINGLE POLE	5.152	0.000	1	6-954 ACSS/TW	139,860	8,455,822	8,595,682				
14	(0996;01) DICKINSON SW STA (GRE)	PARKERS LAKE	345.0	345.0	TOWER	0.148	9.578	1	6-954 ACSR		576,104	576,104				

15	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	SINGLE POLE	0.088	31.458	1	6-954 ACSR		1,648,291	1,648,291				
16	(0994;01) ALLEN S KING	CHISAGO CO.	345.0	345.0	TOWER	0.056	6.604		6-795 ACSR							
17	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	8.839	0.000	1	6-954 ACSR							
18	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	2.654	0.000		6-954 ACSR							
19	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	5.515	14.789		6-954 ACSR	472,775	20,979,702	21,452,477				
20	(0992;02) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	0.309	11.336		6-954 ACSR							
21	(0991;01) MONTICELLO SUB	SHERBURNE CO.	345.0	345.0	TOWER	0.128	5.697	1	6-954 ACSR		196,978	196,978				
22	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	K-FRAME	0.787	0.000	1	6-795 ACSR							
23	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	SINGLE POLE	0.111	0.730		6-795 ACSR							
24	(0989;01) BLUE LAKE	INVER HILLS	345.0	345.0	TOWER	4.064	16.627		6-795 ACSR	80,238	1,436,429	1,516,667				
25	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	H-FRAME	0.532	0.000	1	6-795 ACSR							
26	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	K-FRAME	1.997	0.000		6-795 ACSR							
27	(0989;01) INVER HILLS	RED ROCK	345.0	345.0	TOWER	4.408	1.613		6-795 ACSR	272,767	1,672,480	1,945,247				
28	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.000	2.102	1	6-795 ACSR							
29	(0988;01) BLUE LAKE	PARKERS LAKE	345.0	345.0	TOWER	0.137	12.557		6-795 ACSR		478,209	478,209				
30	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	20.956	1.202	1	6-795 ACSR		7,178,149	7,178,149				
31	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	0.000	5.108		6-795 ACSR							
32	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.000	2.256		6-795 ACSR							
33	(0987;01) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.148	2.335		6-954 ACSR							
34	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	K-FRAME	22.146	0.000	1	6-795 ACSR							
35	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	SINGLE POLE	5.108	0.000		6-795 ACSR	661,692	10,230,595	10,892,287				
36	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	2.256	0.000		6-795 ACSR							
37	(0986;02) PRAIRIE ISLAND	RED ROCK	345.0	345.0	TOWER	0.121	2.357		6-954 ACSR							
38	(0985;01) ELM CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	16.969	0.000	1	6-954 ACSR	17,617	14,477,502	14,495,119				
39	(0985;01) ELM CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	3.362	0.000		6-954 ACSR							
40	(0985;01) ELM CREEK	SHERBURNE CO.	345.0	345.0	TOWER	6.083	5.467		6-954 ACSR							
41	(0985;01) COON CREEK	ELM CREEK	345.0	345.0	SINGLE POLE	0.299	0.942	1	6-954 ACSR	199	163,882	164,081				
42	(0984;01) COON CREEK	SHERBURNE CO.	345.0	345.0	H-FRAME	12.218	0.000	1	6-954 ACSR	506,296	24,916,627	25,422,923				

43	(0984;01) COON CREEK	SHERBURNE CO.	345.0	345.0	K-FRAME	3.569	0.000		6-954 ACSR							
44	(0984;01) COON CREEK	SHERBURNE CO.	345.0	345.0	SINGLE POLE	18.855	0.000		6-954 ACSR							
45	(0984;01) COON CREEK	SHERBURNE CO.	345.0	345.0	TOWER	8.835	0.000		6-954 ACSR							
46	(0984;01) COON CREEK	TERMINAL	345.0	345.0	SINGLE POLE	0.000	4.550	1	6-795 ACSR							
47	(0984;01) COON CREEK	TERMINAL	345.0	345.0	TOWER	0.126	9.028		6-795 ACSR	160,760	3,812,917	3,973,677				
48	(0982;01) BLUE LAKE	SCOTT CO.	345.0	345.0	TOWER	8.156	0.000	1	6-795 ACSR	155,317	1,558,016	1,713,333				
49	(0982;01) CRANDALL	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	2.205	0.000	1	6-795 ACSR	63,508	1,945,935	2,009,443				
50	(0982;01) CRANDALL	WILMARTH	345.0	345.0	H-FRAME	4.300	0.000	1	6-795 ACSR							
51	(0982;01) CRANDALL	WILMARTH	345.0	345.0	K-FRAME	26.859	3.785		6-795 ACSR	548,763	13,367,785	13,916,548				
52	(0982;01) CRANDALL	WILMARTH	345.0	345.0	SINGLE POLE	0.000	17.456		6-556.5 ACSR/T2							
53	(0982;01) HELENA	SCOTT CO.	345.0	345.0	3 POLE	1.421	0.000	1	6-397.5 ZTACSR							
54	(0982;01) HELENA	SCOTT CO.	345.0	345.0	H-FRAME	15.198	0.529		6-397.5 ZTACSR	129,740	26,902,542	27,032,282				
55	(0982;01) HELENA	SHEAS LAKE	345.0	345.0	K-FRAME	7.454	0.000	1	6-795 ACSR	95,480	1,697,636	1,793,116				
56	(0982;01) LAKEFIELD JCT (IPW)	LAKEFIELD GENERATING	345.0	345.0	K-FRAME	18.391	0.294	1	6-795 ACSR	214,005	8,153,743	8,367,748				
57	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	K-FRAME	22.121	0.000	1	6-795 ACSR	271,747	4,589,042	4,860,789				
58	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	SINGLE POLE	0.196	0.000		6-795 ACSR							
59	(0982;01) SHEAS LAKE	WILMARTH	345.0	345.0	TOWER	1.115	0.000		6-795 ACSR							
60	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	K-FRAME	2.682	0.000	1	6-795 ACSR	24,099	872,818	896,917				
61	(0981-MN;01) ALLEN S KING	EAU CLAIRE	345.0	345.0	TOWER	1.532	15.170		6-795 ACSR							
62	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	31.623	0.376	1	6-954 ACSR	4,408,021	41,110,044	45,518,065				
63	(0980;01) CHISAGO CO.	KOHLMAN LAKE	345.0	345.0	TOWER	0.000	5.594		6-795 ACSR							
64	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	SINGLE POLE	4.550	2.816	1	6-795 ACSR							
65	(0980;01) COON CREEK	KOHLMAN LAKE	345.0	345.0	TOWER	7.340	5.235		6-795 ACSR	1,384,573	2,657,526	4,042,099				
66	(0979;01) ADAMS	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	16.854	0.000	1	6-795 ACSR	41,979	5,158,973	5,200,952				
67	(0979;01) BYRON (SMMPA)	NORTH ROCHESTER	345.0	345.0	K-FRAME	13.517	0.000	1	6-795 ACSR	35,037	4,307,001	4,342,038				
68	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	H-FRAME	1.120	0.000	1	6-795 ACSR							
69	(0979;01) BYRON (SMMPA)	PLEASANT VALLEY (GRE)	345.0	345.0	K-FRAME	15.177	0.000		6-795 ACSR	43,098	5,274,529	5,317,627				
70	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	H-FRAME	1.995	0.000	1	6-795 ACSR							

71	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	K-FRAME	25.227	0.000		6-795 ACSR	67,126	11,730,188	11,797,314				
72	(0979;01) NORTH ROCHESTER	PRAIRIE ISLAND	345.0	345.0	TOWER	2.422	0.000		6-954 ACSR							
73	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	H-FRAME	16.962	0.000	1	6-954 ACSR	868,700	16,323,261	17,191,961				
74	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	K-FRAME	3.371	0.000		6-954 ACSR							
75	(0978;01) ELM CREEK	MONTICELLO SUB	345.0	345.0	TOWER	5.776	0.000		6-954 ACSR							
76	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	SINGLE POLE	0.586	0.000	1	6-954 ACSR							
77	(0978;01) ELM CREEK	PARKERS LAKE	345.0	345.0	TOWER	10.447	0.000		6-954 ACSR	13,498	3,803,955	3,817,453				
78	(0977;01) ALLEN S KING	KOHLMAN LAKE	345.0	345.0	TOWER	12.705	0.000	1	6-795 ACSR	1,136,939	2,280,784	3,417,723				
79	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	SINGLE POLE	2.816	0.000	1	6-795 ACSR							
80	(0977;01) KOHLMAN LAKE	TERMINAL	345.0	345.0	TOWER	7.376	0.000		6-795 ACSR	1,136,938	2,189,075	3,326,013				
81	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	SINGLE POLE	3.816	0.000	1	6-795 ACSR	104,148	1,866,654	1,970,802				
82	(0976;01) BLUE LAKE	EDEN PRAIRIE	345.0	345.0	TOWER	1.722	0.000		6-795 ACSR							
83	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	2 POLE	0.659	0.000	1	6-954 ACSR							
84	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	K-FRAME	11.874	0.000		6-954 ACSR							
85	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	SINGLE POLE	0.841	0.000		6-795 ACSR							
86	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	17.117	0.000		6-795 ACSR	873,092	2,859,820	3,732,912				
87	(0976;01) BLUE LAKE	HAMPTON	345.0	345.0	TOWER	3.344	0.000		6-954 ACSR							
88	(0976;01) EDEN PRAIRIE	PARKERS LAKE	345.0	345.0	TOWER	9.391	0.094	1	6-795 ACSR	45,639	521,262	566,901				
89	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	K-FRAME	16.004	0.000	1	6-795 ACSR	1,296,677	6,949,323	8,246,000				
90	(0976;01) HAMPTON	PRAIRIE ISLAND	345.0	345.0	TOWER	3.564	0.000		6-795 ACSR							
91	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	K-FRAME	3.544	0.000	1	6-795 ACSR							
92	(0975;01) ALLEN S KING	RED ROCK	345.0	345.0	TOWER	21.857	0.000		6-795 ACSR	401,128	3,248,399	3,649,527				
93	(0974;01) MANKATO ENERGY CENTER	WILMARTH	345.0	345.0	SINGLE POLE	0.218	0.000	1	6-795 ACSR		888,655	888,655				
94	(0973;01) MONTICELLO SUB	QUARRY	345.0	345.0	SINGLE ^(g) POLE	30.038	0.000	1	6-954 ACSS/TW	5,368,660	10,969,295	16,337,955				
95	(0972;01) HAWKS NEST LAKE	LYON CO.	345.0	345.0	SINGLE ^(d) POLE	30.546	0.000	1	6-954 ACSS/TW	4,933,373	35,536,857	40,470,230				
96	(0972-SD;01) BROOKINGS CO.	HAWKS NEST LAKE	345.0	345.0	SINGLE ^(g) POLE	10.193	0.000	1	6-954 ACSS/TW	509,810	20,993,905	21,503,715				
97	(0972-MN;01) BROOKINGS CO.	HAWKS NEST LAKE	345.0	345.0	SINGLE ^(f) POLE	18.707	0.000	1	6-954 ACSS/TW	3,021,299	21,753,012	24,774,311				
98	(0971;01) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.434	0.000	1	6-795 ACSS	13,748	816,296	830,044				
99	(0970;02) BROOKINGS CO.	WHITE (WAPA)	345.0	345.0	SINGLE POLE	0.378	0.000	1	6-795 ACSS		1,215,849	1,215,849				

100	(0969;02) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.080	0.000	1	6-954							
101	(0968;01) BLAZING STAR 1	STEEP BANK LAKE	345.0	345.0	SINGLE POLE	0.079	0.000	1	6-954		847,917	847,917				
102	(0967;01) HUNTLEY (ITC)	WILMARTH	345.0	345.0	SINGLE POLE	52.026	0.000	1	6-556.5 ACSR/T2	3,004,649	48,897,554	51,902,203				
103	(0966;01) BIG STONE SOUTH	DEUEL (OTP)	345.0	345.0	SINGLE POLE	30.879	0.000	1	6-556.5 ACSR/T2	2,256,494	37,013,225	39,269,719				
104	(0966;01) ASTORIA (OTP)	BROOKINGS CO.	345.0	345.0	SINGLE POLE	16.483	0.000	1	6-556.5 ACSR/T2	505,485	8,291,464	8,796,949				
105	(0966;01) ASTORIA (OTP)	DEUEL (OTP)	345.0	345.0	SINGLE POLE	24.612	0.000	1	6-556.5 ACSR/T2	765,019	12,548,592	13,313,611				
106	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	2 POLE	3.121	0.000	1	6-954 ACSS/TW	5,358,507	59,722,203	65,080,710				
107	(0965-MN;01) BRIGGS ROAD	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	40.065	0.000		6-954 ACSS/TW							
108	(0964;01) HAMPTON	NORTH ROCHESTER	345.0	345.0	SINGLE POLE	37.851	0.000	1	6-397.5 TACSR/VR2	9,431,341	54,128,384	63,559,725				
109	(0962;01) HAZEL CREEK	LYON CO.	345.0	345.0	SINGLE POLE	24.542	0.000	1	6-954 ACSS/TW	340,384	26,971,692	27,312,076				
110	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.0	345.0	3 POLE	0.000	1.317	1	6-954 ACSS/TW							
111	(0961;01) CHUB LAKE (GRE)	HAMPTON	345.0	345.0	SINGLE POLE	0.291	16.494		6-954 ACSS/TW	7,244,068	37,803,259	45,047,327				
112	(0960;01) CHUB LAKE (GRE)	HELENA	345.0	345.0	SINGLE POLE	0.104	20.764	1	6-954 ACSS/TW	8,314,945	36,282,633	44,597,578				
113	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE	0.000	0.906	1	6-954 ACSS/TW							
114	(0959;02) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	0.047	72.109		6-954 ACSS/TW							
115	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	3 POLE	0.906	0.000	1	6-954 ACSS/TW	15,584,347	105,175,230	120,759,577				
116	(0958;01) CEDAR MTN. (GRE)	HELENA	345.0	345.0	SINGLE POLE	72.196	0.000		6-954 ACSS/TW							
117	(0957;02) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	0.000	49.488	1	6-954 ACSS/TW							
118	(0956;01) CEDAR MTN. (GRE)	LYON CO.	345.0	345.0	SINGLE POLE	49.488	0.000	1	6-954 ACSS/TW	5,315,434	65,965,365	71,280,799				
119	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	2 POLE	2.060	0.000	1	6-954 ACSS/TW							
120	(0955-MN;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	102.332	0.000		6-954 ACSS/TW	6,637,015	84,683,466	91,320,481				
121	(0955-ND;01) ALEXANDRIA SW. ST.	BISON	345.0	345.0	SINGLE POLE	34.384	0.000	1	6-954 ACSS/TW	1,513,232	22,705,097	24,218,329				
122	(0954;01) ALEXANDRIA SW. ST.	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	45.160	0.000	1	6-954 ACSS/TW	2,327,849	37,174,146	39,501,995				
123	(0954;01) QUARRY	RIVERVIEW (GRE)	345.0	345.0	SINGLE POLE	36.090	0.000	1	6-954 ACSS/TW	1,860,437	29,709,888	31,570,325				
124	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	22.671	0.000	1	6-397.5 ACSR/T2	3,515,668	56,701,466	60,217,134				
125	(0953;01) LAKEFIELD JCT (IPW)	NOBLES CO.	345.0	345.0	SINGLE POLE	13.270	0.000		6-954 ACSS/TW							
126	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	10.689	0.000	1	6-397.5 ZTACSR							
127	(0953-MN;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	32.044	0.000		6-954 ACSS/TW	3,623,388	69,628,917	73,252,305				
128	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	4.432	0.000	1	6-954 ACSS							

129	(0953-SD;01) NOBLES CO.	SPLIT ROCK	345.0	345.0	SINGLE POLE	5.073	0.000		6-954 ACSS/TW	860,566	11,145,078	12,005,644				
130	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	2 POLE	0.633	0.000	1	6-954 ACSS/TW							
131	(0963;01) HAZEL CREEK	MINNESOTA VALLEY	230.0	345.0	SINGLE POLE	4.336	0.000		6-954 ACSS/TW	355,907	9,176,023	9,531,930				
132	(0929;01) BORDER WIND FARM (RES)	PEACE GARDEN	230.0	230.0	2 POLE	0.042	0.000	1	6-		98,889	98,889				
133	(0928;01) CROWNED RIDGE 1	CROWNED RIDGE 2	230.0	230.0	SINGLE POLE	4.763	0.000	1	3- ACSR		3,173,402	3,173,402				
134	(0927;01) FOXTAIL	FOXTAIL	230.0	230.0	SINGLE POLE	0.115	0.000	1	3-795 ACSR		48,277	48,277				
135	(0924;01) MCHENRY (GRE)	MAGIC CITY	230.0	230.0	SINGLE POLE	20.573	0.000	1	3-477 ACSR/VR2	844,717	26,746,196	27,590,913				
136	(0923;01) CASS LAKE (OTP)	WILTON (MPC)	230.0	230.0	SINGLE POLE	19.318	0.000	1	3-795 ACSS	884,508	9,194,724	10,079,232				
137	(0922;01) BOSWELL (MINNESOTA POWER)	CASS LAKE (OTP)	230.0	230.0	SINGLE POLE	51.461	0.000	1	3-795 ACSS	1,023,124	23,387,110	24,410,234				
138	(0920;01) GLENBORO (MHEB)	PEACE GARDEN	230.0	230.0	H-FRAME	1.985	0.000	1	3-954 ACSR	45,143	438,700	483,843				
139	(0920;01) PEACE GARDEN	RUGBY (OTP)	230.0	230.0	H-FRAME	54.672	0.000	1	3-954 ACSR	1,243,364	12,803,423	14,046,787				
140	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	H-FRAME	2.181	0.000	1	3-795 ACSR							
141	(0919;01) PAYNESVILLE TRANS. S	WILLMAR (GRE)	230.0	230.0	SINGLE POLE	27.554	0.000		3-795 ACSR	302,577	7,615,686	7,918,263				
142	(0918;01) SIOUX FALLS (WAPA)	SPLIT ROCK	230.0	230.0	3 POLE	0.938	0.000	1	3-795 ACSS	531,676	605,867	1,137,543				
143	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	H-FRAME	6.321	0.000	1	3-954 ACSR	24,662	1,546,432	1,571,094				
144	(0916;01) GRAND FORKS (WAPA)	PRAIRIE	230.0	230.0	SINGLE POLE	0.476	0.000		3-954 ACSR							
145	(0915;01) FARGO (WAPA)	SHEYENNE	230.0	230.0	H-FRAME	4.247	0.000	1	3-795 ACSR	21,223	765,985	787,208				
146	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	3 POLE	0.068	0.000	1	3-954 ACSR							
147	(0912;01) DRAYTON (MINNKOTA)	LETELLIER (MANITOBA HYDRO)	230.0	230.0	H-FRAME	28.660	0.000		3-954 ACSR	57,281	3,010,357	3,067,638				
148	(0911;01) AUDUBON (OTP)	SHEYENNE	230.0	230.0	H-FRAME	1.409	0.000	1	3-795 ACSR	10,733	237,425	248,158				
149	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	H-FRAME	2.801	0.000	1	3-795 ACSR	21,002	597,200	618,202				
150	(0911;01) MAPLE RIVER	SHEYENNE	230.0	230.0	TOWER	0.250	3.530		3-795 ACSR							
151	(0910;01) MAPLE RIVER	WAHPETON (MINNKOTA)	230.0	230.0	TOWER	3.604	0.000	1	3-795 ACSR	55,625	283,964	339,589				
152	(0909;01) ERIE JUNCTION (OTP)	HUBBARD (GRE)	230.0	230.0	H-FRAME	26.067	0.000	1	3-795 ACSR	39,347	5,603,428	5,642,775				
153	(0909;01) AUDUBON (OTP)	ERIE JUNCTION (OTP)	230.0	230.0	H-FRAME	12.457	0.000	1	3-795 ACSR	18,516	3,124,397	3,142,913				
154	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	H-FRAME	0.922	0.000	1	3-795 ACSR							
155	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	K-FRAME	52.990	0.000		3-795 ACSR							
156	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	SINGLE POLE	10.985	0.000		3-1272 ACSR	407,857	8,109,966	8,517,823				
157	(0902,0921;01) ROCK CREEK	RUSH CITY (GRE)	230.0	230.0	TOWER	2.783	0.000		3-1272 ACSR							

158	(0902;01) BEAR CREEK (GRE)	ROCK CREEK	230.0	230.0	SINGLE POLE	12.551	0.000	1	3-795 ACSR	29,881	1,250,116	1,279,997				
159	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	H-FRAME	1.340	0.000	1	3-795 ACSR	371,590	5,856,711	6,228,301				
160	(0900;01) BLUE LAKE	MCLEOD (MUNI)	230.0	230.0	TOWER	45.150	0.000		3-795 ACSR							
161	(0900;02) GRANITE FALLS (WAPA)	PANTHER (GRE)	230.0	230.0	TOWER	32.809	0.000	1	3-795 ACSR	5,902	1,864,332	1,870,234				
162	(0900;01) MCLEOD (MUNI)	PANTHER (GRE)	230.0	230.0	TOWER	28.490	0.000	1	3-795 ACSR	59,673	1,519,137	1,578,810				
163	(5313;01) FREEBORN	GLENWORTH (ITC)	161.0	161.0	SINGLE POLE	7.121	0.000	1	3-1272 ACSR		6,203,947	6,203,947				
164	(5312;01) ADAMS	MOWER CO. WIND FARM	161.0	161.0	SINGLE POLE	7.932	0.000	1	3-477 ACSR		1,288,029	1,288,029				
165	(5311;01) PLEASANT VALLEY (GRE)	PLEASANT VALLEY WIND FARM	161.0	161.0	SINGLE POLE	4.982	0.000	1	3-954 ACSR		427,525	427,525				
166	(5310;01) NORTHERN HILLS	NORTH ROCHESTER	161.0	161.0	SINGLE ^(a) POLE	15.507	0.000	1	3-795 ACSS	1,314,415	9,559,156	10,873,571				
167	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE ^(a) POLE	11.408	0.000	1	3-397.5 TACSR/TW	567,003	12,379,705	12,946,708				
168	(5309;01) CHESTER (RPU)	NORTH ROCHESTER	161.0	161.0	SINGLE ^(a) POLE	1.866	14.388		6-954 ACSS/TW							
169	(5308;01) GRAND MEADOW	PLEASANT VALLEY (GRE)	161.0	161.0	SINGLE POLE	5.703	0.000	1	6-795 ACSS		3,667,734	3,667,734				
170	(5306;01) BYRON (SMPMA)	PLEASANT VALLEY (GRE)	161.0	161.0	SINGLE POLE	16.604	0.000	1	3-795 ACSS	477,246	6,134,098	6,611,344				
171	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	SINGLE POLE	1.567	0.000	1	3-795 ACSS	69,923	10,278,048	10,347,971				
172	(5305-MN;01) LAWRENCE CREEK	ST CROIX FALLS	161.0	161.0	UNDERGROUND	0.579	0.000		3-3000 CU							
173	(5301;01) ELK (ITC)	ROCK CO.	161.0	161.0	H-FRAME	5.389	0.000	1	3-477 ACSR	16,110	650,054	666,164				
174	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	H-FRAME	3.453	0.000	1	3-477 ACSR	17,390	603,450	620,840				
175	(5301-MN;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.037	0.000		3-477 ACSR							
176	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	H-FRAME	10.274	0.000	1	3-477 ACSR	25,772	1,548,304	1,574,076				
177	(5301-SD;01) ROCK CO.	SPLIT ROCK	161.0	161.0	SINGLE POLE	0.867	0.000		3-2312 ACSR							
178	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	SINGLE POLE	31.376	0.000	1	3-636 ACSR/VR2	143,079	31,815,613	31,958,692				
179	(5300;01) HUNTLEY (ITC)	SOUTH BEND	161.0	161.0	SINGLE POLE	0.118	0.000		3-795 ACSS							
180	SUMMARY OF 115 KV SYSTEM		115.0	115.0	^(a) Overhead	1,476.698	156.685			25,989,561	830,318,057	856,307,618				
181	SUMMARY OF 115 KV SYSTEM		115.0	115.0	Underground	13.221	0.000									
182	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Overhead	1,494.574	88.839			8,369,192	628,116,049	636,485,241				
183	SUMMARY OF 69 KV SYSTEM		69.0	69.0	Underground	1.532	0.000									
184	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Overhead	61.959	30.632			436,068	29,234,653	29,670,721				
185	SUMMARY OF 34.5 KV SYSTEM		34.5	34.5	Underground	0.590	0.000									
186	Expenses, except depreciation and taxes												990,885	5,631,258	1,444,446	8,066,589
36	TOTAL					5,255.940	700.298	112		157,082,217	3,052,082,419	3,209,164,636	990,885	5,631,258	1,444,446	8,066,589

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: SupportingStructureOfTransmissionLineType NSM ((5653-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 62.2394%(6.343 miles) of 10.192 miles of this circuit: remaining 37.7606%(3.849 miles) is owned by other members of a joint venture partnership Schedule Page: 422 Line No.: 1.20 Column: e NSM ((5653;01) LYON CO.-STEEP BANK LAKE) : Xcel Energy owns 62.2394%(25.122 miles) of 40.363 miles of this circuit: remaining 37.7606%(15.241 miles) is owned by other members of a joint venture partnership (b) Concept: SupportingStructureOfTransmissionLineType NSM ((5653-MN;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 62.2394%(5.516 miles) of 8.862 miles of this circuit: remaining 37.7606%(3.346 miles) is owned by other members of a joint venture partnership (c) Concept: SupportingStructureOfTransmissionLineType NSM ((0973;01) MONTICELLO SUB-QUARRY) : Xcel Energy owns 36.1%(10.84 miles) of 30.04 miles of this circuit: remaining 63.9%(19.19 miles) is owned by other members of a joint venture partnership (d) Concept: SupportingStructureOfTransmissionLineType NSM ((0972;01) HAWKS NEST LAKE-LYON CO.) : Xcel Energy owns 67.7971%(20.709 miles) of 30.546 miles of this circuit: remaining 32.2029%(9.837 miles) is owned by other members of a joint venture partnership (e) Concept: SupportingStructureOfTransmissionLineType NSM ((0972-SD;01) BROOKINGS CO.-STEEP BANK LAKE) : Xcel Energy owns 67.8%(6.91 miles) of 10.19 miles of this circuit: remaining 32.2%(3.28 miles) is owned by other members of a joint venture partnership (f) Concept: SupportingStructureOfTransmissionLineType NSM ((0972-MN;01) BROOKINGS CO.-HAWKS NEST LAKE) : Xcel Energy owns 67.7971%(12.683 miles) of 18.707 miles of this circuit: remaining 32.2029%(6.024 miles) is owned by other members of a joint venture partnership (g) Concept: SupportingStructureOfTransmissionLineType NSM ((0967;01) HUNTLEY (ITC)-WILMARTH) : Xcel Energy owns 50.0%(26.01 miles) of 52.03 miles of this circuit: remaining 50.0%(26.01 miles) is owned by other operating companies (h) Concept: SupportingStructureOfTransmissionLineType NSM ((0966;01) BIG STONE SOUTH-DEUEL (OTP)) : Xcel Energy owns 50%(15.44 miles) of 30.879 miles of this circuit: remaining 50%(15.44 miles) is owned by other members of a joint venture partnership (i) Concept: SupportingStructureOfTransmissionLineType NSM ((0966;01) ASTORIA (OTP)-BROOKINGS CO.) : Xcel Energy owns 50%(8.242 miles) of 16.483 miles of this circuit: remaining 50%(8.242 miles) is owned by other members of a joint venture partnership (j) Concept: SupportingStructureOfTransmissionLineType NSM ((0966;01) ASTORIA (OTP)-DEUEL (OTP)) : Xcel Energy owns 50%(12.306 miles) of 24.612 miles of this circuit: remaining 50%(12.306 miles) is owned by other members of a joint venture partnership (k) Concept: SupportingStructureOfTransmissionLineType NSM ((0965-MN;01) BRIGGS ROAD-NORTH ROCHESTER) : Xcel Energy owns 64.0%(27.64 miles) of 43.19 miles of this circuit: remaining 36.0%(15.55 miles) is owned by other members of a joint venture partnership (l) Concept: SupportingStructureOfTransmissionLineType NSM ((0964;01) HAMPTON-NORTH ROCHESTER) : Xcel Energy owns 64.0%(24.22 miles) of 37.85 miles of this circuit: remaining 36.0%(13.63 miles) is owned by other members of a joint venture partnership (m) Concept: SupportingStructureOfTransmissionLineType NSM ((0962;01) HAZEL CREEK-LYON CO.) : Xcel Energy owns 67.8%(16.64 miles) of 24.54 miles of this circuit: remaining 32.2%(7.9 miles) is owned by other members of a joint venture partnership (n) Concept: SupportingStructureOfTransmissionLineType NSM ((0961;01) CHUB LAKE (GRE)-HAMPTON) : Xcel Energy owns 67.8%(12.27 miles) of 18.1 miles of this circuit: remaining 32.2%(5.83 miles) is owned by other members of a joint venture partnership (o) Concept: SupportingStructureOfTransmissionLineType NSM ((0960;01) CHUB LAKE (GRE)-HELENA) : Xcel Energy owns 67.8%(14.15 miles) of 20.87 miles of this circuit: remaining 32.2%(6.72 miles) is owned by other members of a joint venture partnership (p) Concept: SupportingStructureOfTransmissionLineType NSM ((0959;02) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.53 miles) of 73.06 miles of this circuit: remaining 32.2%(23.53 miles) is owned by other members of a joint venture partnership (q) Concept: SupportingStructureOfTransmissionLineType NSM ((0958;01) CEDAR MTN. (GRE)-HELENA) : Xcel Energy owns 67.8%(49.56 miles) of 73.1 miles of this circuit: remaining 32.2%(23.54 miles) is owned by other members of a joint venture partnership (r) Concept: SupportingStructureOfTransmissionLineType NSM ((0957;02) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership (s) Concept: SupportingStructureOfTransmissionLineType			

NSM ((0956;01) CEDAR MTN. (GRE)-LYON CO.) : Xcel Energy owns 67.8%(33.55 miles) of 49.49 miles of this circuit: remaining 32.2%(15.94 miles) is owned by other members of a joint venture partnership
(t) Concept: SupportingStructureOfTransmissionLineType
NSM ((0955-MN;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(37.69 miles) of 104.39 miles of this circuit: remaining 63.9%(66.71 miles) is owned by other members of a joint venture partnership
(u) Concept: SupportingStructureOfTransmissionLineType
NSM ((0955-ND;01) ALEXANDRIA SW. ST.-BISON) : Xcel Energy owns 36.1%(12.41 miles) of 34.38 miles of this circuit: remaining 63.9%(21.97 miles) is owned by other members of a joint venture partnership
(v) Concept: SupportingStructureOfTransmissionLineType
NSM ((0954;01) ALEXANDRIA SW. ST.-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(16.3 miles) of 45.16 miles of this circuit: remaining 63.9%(28.86 miles) is owned by other members of a joint venture partnership
(w) Concept: SupportingStructureOfTransmissionLineType
NSM ((0954;01) QUARRY-RIVERVIEW (GRE)) : Xcel Energy owns 36.1%(13.03 miles) of 36.09 miles of this circuit: remaining 63.9%(23.06 miles) is owned by other members of a joint venture partnership
(x) Concept: SupportingStructureOfTransmissionLineType
NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8%(3.37 miles) of 4.97 miles of this circuit: remaining 32.2%(1.6 miles) is owned by other members of a joint venture partnership
(y) Concept: SupportingStructureOfTransmissionLineType
NSM ((0963;01) HAZEL CREEK-MINNESOTA VALLEY) : Xcel Energy owns 67.8%(3.37 miles) of 4.97 miles of this circuit: remaining 32.2%(1.6 miles) is owned by other members of a joint venture partnership
(z) Concept: SupportingStructureOfTransmissionLineType
NSM ((0923;01) CASS LAKE (OTP)-WILTON (MPC)) : Xcel Energy owns 26.2%(5.06 miles) of 19.32 miles of this circuit: remaining 73.8%(14.26 miles) is owned by other members of a joint venture partnership
(aa) Concept: SupportingStructureOfTransmissionLineType
NSM ((0922;01) BOSWELL (MINNESOTA POWER)-CASS LAKE (OTP)) : Xcel Energy owns 26.2%(13.48 miles) of 51.46 miles of this circuit: remaining 73.8%(37.98 miles) is owned by other members of a joint venture
(ab) Concept: SupportingStructureOfTransmissionLineType
NSM ((5310;01) NORTHERN HILLS-NORTH ROCHESTER) : Xcel Energy owns 64.0%(9.92 miles) of 15.51 miles of this circuit: remaining 36.0%(5.58 miles) is owned by other members of a joint venture partnership
(ac) Concept: SupportingStructureOfTransmissionLineType
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(ad) Concept: SupportingStructureOfTransmissionLineType
NSM ((5309;01) CHESTER (RPU)-NORTH ROCHESTER) : Xcel Energy owns 64.0%(17.7 miles) of 27.66 miles of this circuit: remaining 36.0%(9.96 miles) is owned by other members of a joint venture partnership
(ae) Concept: SupportingStructureOfTransmissionLineType
NSM ((5558;01) CEDAR MTN. (GRE)-FRANKLIN) : Xcel Energy owns 67.8%(2.92 miles) of 4.3 miles of this circuit: remaining 32.2%(1.39 miles) is owned by other members of a joint venture partnership

Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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 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.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	(5654;01) HAMPTON	HELENA	1.317	3 POLE	6	2	2	3-397.5	ZTACSR-VR2	26/7	345.0		104,597	836,206		940,803	
2	(5654;01) HAMPTON	HELENA	37.689	SINGLE POLE	6	2	2	3-397.5	ZTACSR-VR2	26/7	345.0		2,993,287	23,929,973		26,923,260	
3	(5652;01) SHERBURNE CO.	SHERCO SOLAR EAST	2.040	SINGLE POLE	7	2	2	3-556.5 kmcil	ACSR/VR2	26/7	345.0		7,015,027	1,359,485		8,374,512	
4	(5651;01) SHERBURNE CO.	SHERCO SOLAR WEST	1.239	SINGLE POLE	8	1	1	3-556.5	ACSR/VR2	26/7	345.0		1,500,141	1,364,964		2,865,105	
5	(0832;01) CHUB LAKE (GRE)	FARIBAULT ENERGY PARK	0.15	H-FRAME	8	1	1	3-795	ACSS	26/7	115.0		601,617	171,628		773,245	
6	(5578;01) EMPIRE	UMORE PARK	0.65	SINGLE POLE	9	1	1	3-954	ACSS	54/7	115.0						
7	(5509;01) GRANITE CITY	MAYHEW LAKE	0.06	SINGLE POLE	17	1	1	3-795	ACSR	45/7	115.0						
8	(5579;01) ROSEMOUNT	UMORE PARK	0.65	SINGLE POLE	13	1	1	3-954	ACSS	54/7	115.0						
9	(5412;01) AVERILL	MAPLE RIVER	0.03	3WAY NONSWITCH	80	1	1	3-266.8	ACSR	26/7	69.0		50,540	65,608		116,148	
10	(5412;01) AVERILL	MAPLE RIVER	0.05	SINGLE POLE	80	1	1	3-266.8	ACSR	26/7	69.0		50,540	65,608		116,148	
11	(0729,0730;01) CLIFF AVENUE	SOUTH SIOUX FALLS	0.56	SINGLE POLE	23	1	1	3-795	ACSR	26/7	69.0		5,483,516	642,950		6,126,466	
12	(0749;01) LOON LAKE	WASECA JCT (ITC)	0.07	SINGLE POLE	19	1	1	3-336.4	ACSR/VR2	26/7	69.0		3,907,487	2,486,569		6,394,056	
13	(0724;01) NIGHTHAWK	TROY SW. ST.	0.02	SINGLE POLE	20	1	1	3-4/0	ACSR	6/1	69.0						
14	(0724;01) NIGHTHAWK	TROY SW. ST.	0.15	SINGLE POLE	20	1	1	3-477	ACSR	26/7	69.0						
44	TOTAL		45		316	17	17						21,706,752	30,922,991		52,629,743	

Name of Respondent: Northern States Power Company (Minnesota)				This report is: (1) ☒ An Original (2) ☐ A Resubmission			Date of Report: 04/09/2026		Year/Period of Report End of: 2025/ 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). 5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity. 6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.												
Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	ADAMS-TR09	Transmission	Unattended	345.00	161.00	13.80	300.00	1				
2	ADA-TR01	Distribution	Unattended	69.00	23.00	4.16	14.00	1				
3	AFTON-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
4	AFTON-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
5	AIR LAKE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
6	AIR LAKE-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
7	AIRPORT-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
8	AIRPORT-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
9	ALBANY-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
10	ALDRICH-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
11	ALDRICH-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
12	ALDRICH-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
13	ALEXANDRIA-TR01ABC	Distribution	Unattended	34.50	4.16		2.00	3				
14	ALTURA-TR01	Distribution	Unattended	69.00	13.80		7.00	1				
15	ANNANDALE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
16	APACHE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
17	APACHE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
18	ARDEN HILLS-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
19	ARDEN HILLS-TR02	Transmission	Unattended	115.00	69.00	13.80	70.00	1				
20	ARLINGTON-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
21	AS KING-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
22	AS KING-TR91	Distribution	Unattended	115.00	34.50		25.00	1				
23	ATWATER-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
24	AVERILL-TR01	Distribution	Unattended	69.00	23.00	4.00	14.00	1				
25	AVON-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
26	BASSETT CREEK-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
27	BASSETT CREEK-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
28	BATTLE CREEK-TR01	Distribution	Unattended	115.00	13.80		48.00	1				

29	BATTLE CREEK-TR02	Distribution	Unattended	115.00	13.80		48.00	1				
30	BAYTOWN-TR01	Distribution	Unattended	118.00	13.80		28.00	1				
31	BECKER-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
32	BECKER-TR02	Distribution	Unattended	69.00	34.50		4.70	1				
33	BELLE PLAINE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
34	BIRCH-TR01	Distribution	Unattended	69.00	34.50		14.00	1				
35	BIRD ISLAND-TR02	Distribution	Unattended	69.00	4.16		2.50	1				
36	BLUE HERON-TR01	Distribution	Unattended	69.00	13.80		9.40	1				
37	BLUE LAKE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
38	BLUE LAKE-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
39	BLUE LAKE-TR07	Transmission	Unattended	230.00	115.00	13.80	336.00	1				
40	BLUE LAKE-TR09	Transmission	Unattended	345.00	115.00	14.00	336.00	1				
41	BLUFF CREEK-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
42	BLUFF CREEK-TR05	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
43	BROOKINGS COUNTY-TR09	Transmission	Unattended	345.00	115.00	34.50	448.00	1				
44	BROOKINGS COUNTY-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
45	BROOKLYN PARK-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
46	BROOKLYN PARK-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
47	BROOTEN-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
48	BROWNTON-TR01	Distribution	Unattended	69.00	2.40		1.40	1				
49	BUFFALO LAKE-TR01	Distribution	Unattended	69.00	12.50		5.60	1				
50	BUFFALO RIDGE-TR01	Distribution	Unattended	115.00	34.50	13.80	120.00	1				
51	BUFFALO RIDGE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
52	BURNSIDE-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
53	BURNSIDE-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
54	BUTTERFIELD-TR01	Distribution	Unattended	69.00	4.16		1.50	1				
55	CANISTOTA JCT-TR01	Distribution	Unattended	69.00	13.80		8.00	1				
56	CANISTOTA-TR01ABC	Distribution	Unattended	69.00	4.16		3.00	3				
57	CANNON FALLS XMSN-TR06	Transmission	Unattended	115.00	69.00	13.80	112.00	1				
58	CANNON FALLS XMSN-TR07	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
59	CANNON FALLS-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
60	CANTON-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
61	CANTON-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
62	CARVER COUNTY-TR01	Transmission	Unattended	115.00	69.00	35.00	70.00	1				
63	CARVER COUNTY-TR02	Transmission	Unattended	115.00	69.00	35.00	70.00	1				
64	CASS COUNTY-TR01XY	Distribution	Unattended	115.00	23.00	3.00	50.00	2				
65	CASS COUNTY-TR02	Distribution	Unattended	115.00	23.00		47.00	1				
66	CASS COUNTY-TR03	Distribution	Unattended	115.00	23.00	14.00	46.70	1				
67	CASTLE ROCK-TR01	Distribution	Unattended	69.00	4.00		1.00	1				
68	CEDAR LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
69	CEDAR LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				

70	CEDARVALE-TR01	Distribution	Unattended	115.00	13.80		20.00	1				
71	CEDARVALE-TR02	Distribution	Unattended	115.00	13.80		23.00	1				
72	CENTERVILLE-TR01	Distribution	Unattended	69.00	13.80		7.00	1				
73	CHANARAMBIE-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
74	CHANARAMBIE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
75	CHANARAMBIE-TR04	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
76	CHEMOLITE-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
77	CHEMOLITE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
78	CHERRY CREEK-TR01	Distribution	Unattended	115.00	13.80		37.00	1				
79	CHERRY CREEK-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
80	CHISAGO COUNTY-TR02	Distribution	Unattended	115.00	34.50		47.00	1				
81	CHISAGO COUNTY-TR05	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
82	CHISAGO COUNTY-TR06	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
83	CHISAGO COUNTY-TR09ABC	Transmission	Unattended	500.00	345.00	35.00	1203.00	3				
84	CHISAGO COUNTY-TR10ABC	Transmission	Unattended	500.00	345.00	35.00	1203.00	3				
85	CLARA CITY-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
86	CLARA CITY-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
87	CLARKS GROVE-TR01	Distribution	Unattended	69.00	7.20		2.00	1				
88	CLIFF AVENUE-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
89	CLIFF AVENUE-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
90	COKATO-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
91	COLVILL-TR04	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
92	COLVILL-TR05	Transmission	Unattended	161.00	115.00	14.00	187.00	1				
93	COON CREEK-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
94	COON CREEK-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
95	COON CREEK-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
96	COON CREEK-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
97	COTTAGE GROVE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
98	COTTAGE GROVE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
99	CREDIT RIVER-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
100	CREDIT RIVER-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
101	CROOKED LAKE-TR01	Distribution	Unattended	119.00	13.80		46.70	1				
102	CROOKED LAKE-TR02	Distribution	Unattended	119.00	13.80		46.70	1				
103	CROOKED LAKE-TR03	Distribution	Unattended	115.00	12.50		28.00	1				
104	CROOKED LAKE-TR65ABC	Distribution	Unattended	13.80	12.50		10.00	3				
105	CROSSROADS-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
106	CROSSROADS-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
107	CROSSROADS-TR03	Distribution	Unattended	115.00	13.80		22.00	1				
108	CRYSTAL FOODS-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
109	DAHLGREN-TR01	Distribution	Unattended	115.00	13.80		14.00	1				
110	DANUBE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				

111	DASSEL-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
112	DAYTONS BLUFF-TR01	Distribution	Unattended	115.00	13.80		63.00	1				
113	DAYTONS BLUFF-TR02	Distribution	Unattended	115.00	13.80		63.00	1				
114	DAYTONS BLUFF-TR03	Distribution	Unattended	115.00	13.80		63.00	1				
115	DEEPHAVEN-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
116	DEEPHAVEN-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
117	DELANO-TR01XY	Distribution	Unattended	69.00	7.20		0.40	2				
118	DELL RAPIDS-TR02	Distribution	Unattended	34.50	12.50		10.50	1				
119	DODGE CENTER-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
120	DODGE CENTER-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
121	DODGE CENTER-TR03	Distribution	Unattended	69.00	12.50		10.50	1				
122	DOME PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1				
123	DOUGLAS COUNTY-TR01	Transmission	Unattended	115.00	69.00	35.00	46.70	1				
124	DOUGLAS COUNTY-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
125	DOUGLAS COUNTY-TR03	Distribution	Unattended	69.00	13.80		7.20	1				
126	DUNDAS-TR01	Distribution	Unattended	69.00	13.80		20.00	1				
127	DUNDAS-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
128	EAGLE LAKE-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
129	EAST BLOOMINGTON-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
130	EAST BLOOMINGTON-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
131	EAST BLOOMINGTON-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
132	EAST WINONA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
133	EASTWOOD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
134	EASTWOOD-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
135	EASTWOOD-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
136	EDEN PRAIRIE-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
137	EDEN PRAIRIE-TR03	Distribution	Unattended	115.00	13.80		47.00	1				
138	EDEN PRAIRIE-TR04	Distribution	Unattended	115.00	13.80		51.00	1				
139	EDEN PRAIRIE-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
140	EDEN PRAIRIE-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
141	EDGERTON-TR01	Distribution	Unattended	23.00	4.16		2.00	1				
142	EDINA-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
143	EDINA-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
144	EDINA-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
145	ELLIOT PARK-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
146	ELLIOT PARK-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
147	ELLIOT PARK-TR03	Distribution	Unattended	115.00	13.80		72.50	1				
148	ELM CREEK-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
149	ELM CREEK-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
150	ELM CREEK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
151	ELM CREEK-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				

152	EMERY-TR01ABC	Distribution	Unattended	34.50	4.16		1.50	3				
153	ESSIG-TR01ABC	Distribution	Unattended	69.00	2.40		0.45	3				
154	EXCELSIOR-TR01	Distribution	Unattended	69.00	13.80		19.00	1				
155	FAIR PARK-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
156	FAIR PARK-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
157	FALLS-TR01	Distribution	Unattended	115.00	13.80		62.60	1				
158	FALLS-TR02	Distribution	Unattended	115.00	13.80		62.60	1				
159	FARIBAULT-TR01	Distribution	Unattended	69.00	13.80		22.40	1				
160	FARIBAULT-TR02	Distribution	Unattended	69.00	13.80		14.00	1				
161	FARMINGTON-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
162	FARMINGTON-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
163	FENTON-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
164	FENTON-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
165	FENTON-TR05	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
166	FIESTA CITY-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
167	FIESTA CITY-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
168	FIFTH STREET-TR01	Distribution	Unattended	115.00	13.80		84.00	1				
169	FIFTH STREET-TR02	Distribution	Unattended	115.00	13.80		84.00	1				
170	FIFTH STREET-TR03	Distribution	Unattended	115.00	13.80		84.00	1				
171	FIFTH STREET-TR04	Distribution	Unattended	115.00	13.80		84.00	1				
172	FIRST LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
173	FOLEY-TR01	Distribution	Unattended	34.50	4.16		3.00	1				
174	FORBES-TR09	Distribution	Unattended	500.00	20.00		168.00	1				
175	FORT RIDGELY-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
176	FRANKLIN-TR04	Distribution	Unattended	69.00	23.00		7.00	1				
177	FRANKLIN-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
178	FRANKLIN-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
179	FRANKLIN-TR07	Distribution	Unattended	69.00	4.16		2.00	1				
180	FRONTENAC-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
181	GATEWAY-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
182	GATEWAY-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
183	GAYLORD-TR01	Distribution	Unattended	69.00	4.00		5.00	1				
184	GIBBON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
185	GLEASON LAKE-TR01	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
186	GLEASON LAKE-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
187	GLEASON LAKE-TR04	Distribution	Unattended	115.00	34.50		70.00	1				
188	GLEASON LAKE-TR07	Distribution	Unattended	115.00	13.80		47.00	1				
189	GLEASON LAKE-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
190	GLEN LAKE-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
191	GLEN LAKE-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
192	GLENWOOD-TR01	Distribution	Unattended	69.00	13.80		14.00	1				

193	GLENWOOD-TR02	Distribution	Unattended	69.00	12.50		5.00	1				
194	GOODVIEW-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
195	GOODVIEW-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
196	GOOSE LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
197	GOOSE LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
198	GOPHER-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
199	GOPHER-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
200	GRANITE CITY-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
201	GRANITE CITY-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
202	GRANITE CITY-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
203	GRANT-TR01	Transmission	Unattended	115.00	69.00	14.00	25.00	1				
204	GRANT-TR03	Distribution	Unattended	115.00	34.50		46.70	1				
205	GREAT PLAINS-TR01	Distribution	Unattended	115.00	14.30		50.00	1				
206	GREEN ISLE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
207	GREENFIELD-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
208	HADLEY-TR01	Distribution	Unattended	69.00	13.80		2.80	1				
209	HASSAN-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
210	HASSAN-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
211	HASTINGS-TR01	Distribution	Unattended	69.00	12.50		28.00	1				
212	HASTINGS-TR02	Distribution	Unattended	69.00	12.50		28.00	1				
213	HATFIELD-TR01ABC	Distribution	Unattended	23.00	12.50		2.00	3				
214	HATTON-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
215	HAZEL CREEK-TR09	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
216	HECTOR-TR01	Distribution	Unattended	69.00	4.16		3.00	1				
217	HENDERSON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
218	HIAWATHA WEST-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
219	HIGH BRIDGE-TR04	Distribution	Unattended	115.00	13.80		46.70	1				
220	HOLLYDALE-TR01	Distribution	Unattended	69.00	13.80		25.00	1				
221	HOLLYDALE-TR02	Distribution	Unattended	34.50	13.80		28.00	1				
222	HOWARD LAKE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
223	HUGO-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
224	HUGO-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
225	HYLAND LAKE-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
226	HYLAND LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
227	INDIANA-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
228	INDIANA-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
229	INVER GROVE-TR01	Transmission	Unattended	115.00	69.00	14.00	63.00	1				
230	INVER GROVE-TR02	Transmission	Unattended	115.00	69.00	14.00	63.00	1				
231	INVER HILLS-PLTSDU	Distribution	Unattended	34.50	13.80		1.00	1				
232	INVER HILLS-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
233	JAMAICA-TR01	Distribution	Unattended	115.00	13.80		70.00	1				

234	JORDAN-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
235	KASSON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
236	KASSON-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
237	KEGAN LAKE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
238	KENYON-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
239	KIMBALL-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
240	KOCH REFINERY-TR11	Distribution	Unattended	115.00	13.80		46.70	1				
241	KOCH REFINERY-TR12	Distribution	Unattended	115.00	13.80		46.70	1				
242	KOCH REFINERY-TR13	Distribution	Unattended	115.00	13.80		46.70	1				
243	KOCH REFINERY-TR14	Distribution	Unattended	115.00	13.80		46.70	1				
244	KOCH REFINERY-TR15	Distribution	Unattended	115.00	13.80		46.70	1				
245	KOCH REFINERY-TR16	Distribution	Unattended	115.00	13.80		46.70	1				
246	KOHLMAN LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
247	KOHLMAN LAKE-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
248	KOHLMAN LAKE-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
249	KOHLMAN LAKE-TR10	Transmission	Unattended	345.00	115.00	14.00	450.00	1				
250	LA CRESCENT-TR01	Distribution	Unattended	69.00	13.80		16.00	1				
251	LAFAYETTE-TR01	Distribution	Unattended	69.00	4.16		1.00	1				
252	LAKE BAVARIA-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
253	LAKE EMILY-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
254	LAKE LILLIAN-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
255	LAKE PULASKI-TR03	Distribution	Unattended	115.00	34.50		28.00	1				
256	LAKE PULASKI-TR05	Transmission	Unattended	115.00	69.00	35.00	46.70	1				
257	LAKE PULASKI-TR06	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
258	LAKE YANKTON-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
259	LAKE YANKTON-TR02	Transmission	Unattended	115.00	69.00	14.00	15.00	1				
260	LAKE YANKTON-TR03	Distribution	Unattended	69.00	13.80		10.50	1				
261	LARIMORE-TR01	Distribution	Unattended	69.00	4.16		4.00	1				
262	LAWRENCE CREEK-TR01	Distribution	Unattended	115.00	34.50		28.00	1				
263	LAWRENCE CREEK-TR04	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
264	LAWRENCE CREEK-TR05	Transmission	Unattended	161.00	115.00	14.00	336.00	1				
265	LAWRENCE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
266	LAWRENCE-TR07	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
267	LAWRENCE-TR08	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
268	LENNOX-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
269	LESTER PRAIRIE-TR01	Distribution	Unattended	69.00	13.80		9.00	1				
270	LEXINGTON-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
271	LEXINGTON-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
272	LEXINGTON-TR03	Distribution	Unattended	115.00	34.50		70.00	1				
273	LEXINGTON-TR04	Distribution	Unattended	34.50	13.80		46.70	1				
274	LINCOLN COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				

275	LINCOLN COUNTY-TR07	Distribution	Unattended	115.00	13.80		50.00	1				
276	LINCOLN COUNTY-TR08	Distribution	Unattended	115.00	13.80		50.00	1				
277	LINDE-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
278	LINDSTROM-TR01	Distribution	Unattended	115.00	12.50		28.70	1				
279	LINDSTROM-TR02	Distribution	Unattended	115.00	12.50		28.70	1				
280	LINN STREET-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
281	LINN STREET-TR02	Distribution	Unattended	69.00	12.50		10.50	1				
282	LONE OAK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
283	LONE OAK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
284	LONG LAKE-TR01	Distribution	Unattended	115.00	13.80		12.00	1				
285	LONG LAKE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
286	LOUISE-TR01	Distribution	Unattended	115.00	13.80		51.50	1				
287	LOWRY-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
288	LYON COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
289	LYON COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	270.00	1				
290	M E INTERNATIONAL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
291	M E INTERNATIONAL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
292	MAIN STREET-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
293	MAIN STREET-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
294	MAPLE LAKE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
295	MAPLE RIVER-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
296	MAPLE RIVER-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
297	MAPLETON-TR01	Distribution	Unattended	69.00	13.80		6.00	1				
298	MARION-TR01	Distribution	Unattended	23.00	4.16		4.00	1				
299	MAYHEW LAKE-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
300	MAYNARD TRANSMISSION-TR01	Transmission	Unattended	115.00	69.00		46.70	1				
301	MAYNARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
302	MAYVILLE-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
303	MAYVILLE-TR02	Distribution	Unattended	69.00	12.50		14.00	1				
304	MAZEPPA-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
305	MEDFORD JUNCTION-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
306	MEDICINE LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
307	MEDICINE LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
308	MEDICINE LAKE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
309	MEIRE GROVE-TR01	Distribution	Unattended	69.00	12.50		2.00	1				
310	MERIDEN-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
311	MERRIAM PARK-TR01	Distribution	Unattended	115.00	13.80		63.00	1				
312	MERRIAM PARK-TR02	Distribution	Unattended	115.00	13.80		72.00	1				
313	MERRIAM PARK-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
314	MIDTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
315	MINNEHAHA-TR01	Distribution	Unattended	115.00	13.80		28.00	1				

316	MINNEHAHA-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
317	MINNESOTA LAKE-TR01	Distribution	Unattended	69.00	4.16		2.00	1				
318	MINNESOTA PIPELINE-TR01	Distribution	Unattended	115.00	4.16		8.00	1				
319	MINNESOTA VALLEY-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
320	MINNESOTA VALLEY-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
321	MINNESOTA VALLEY-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
322	MINNESOTA VALLEY-TR11	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
323	MINNESOTA VALLEY-TR12	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
324	MONTEVIDEO-TR01	Distribution	Unattended	69.00	4.16		6.00	1				
325	MONTEVIDEO-TR02	Distribution	Unattended	69.00	12.50		5.00	1				
326	MONTICELLO-TR06	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
327	MONTICELLO-TR10	Transmission	Unattended	345.00	115.00	14.00	345.00	1				
328	MONTROSE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
329	MOORE LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
330	MOORE LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
331	MOORE LAKE-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
332	MORGAN-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
333	MORRISTOWN-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
334	MOUND-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
335	MOUND-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
336	NERSTRAND-TR01XY	Distribution	Unattended	69.00	12.50		3.00	2				
337	NINE MILE CREEK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
338	NINE MILE CREEK-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
339	NOBLES COUNTY-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
340	NOBLES COUNTY-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
341	NOBLES COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
342	NOBLES COUNTY-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
343	NORDIC-TR01	Distribution	Unattended	115.00	13.80		47.00	1				
344	NORDIC-TR02	Distribution	Unattended	115.00	13.80		47.00	1				
345	NORTH BROADWAY-TR01	Distribution	Unattended	23.00	4.16		5.00	1				
346	NORTH BROADWAY-TR02	Distribution	Unattended	23.00	4.16		5.00	1				
347	NORTH ROCHESTER-TR09	Transmission	Unattended	345.00	161.00	35.00	672.00	1				
348	NORTHFIELD-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
349	NORTHFIELD-TR02	Distribution	Unattended	69.00	13.80		17.00	1				
350	OAK PARK-TR01	Distribution	Unattended	115.00	23.00	14.00	28.00	1				
351	OAK PARK-TR07	Distribution	Unattended	115.00	13.80		46.70	1				
352	OAK PARK-TR08	Distribution	Unattended	115.00	13.80		46.70	1				
353	OAKDALE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
354	OAKDALE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
355	ORONO-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
356	OSSEO-TR01	Distribution	Unattended	115.00	13.80		70.00	1				

357	OSSEO-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
358	PARKERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
359	PARKERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
360	PARKERS LAKE-TR03	Distribution	Unattended	115.00	13.80		50.00	1				
361	PARKERS LAKE-TR09ABC	Transmission	Unattended	345.00	115.00	14.00	450.00	3				
362	PARKERS LAKE-TR10ABC	Transmission	Unattended	345.00	115.00	14.00	450.00	3				
363	PAYNESVILLE XMSN-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
364	PAYNESVILLE XMSN-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
365	PAYNESVILLE XMSN-TR04	Distribution	Unattended	115.00	34.50		28.00	1				
366	PAYNESVILLE XMSN-TR09	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
367	PINE BEND-TR03	Distribution	Unattended	69.00	13.80		14.00	1				
368	PINE ISLAND-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
369	PINE ISLAND-TR02	Distribution	Unattended	69.00	12.50		7.00	1				
370	PIPESTONE-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
371	PIPESTONE-TR02	Distribution	Unattended	69.00	4.16		9.00	1				
372	PIPESTONE-TR03	Distribution	Unattended	69.00	25.00		6.00	1				
373	PIPESTONE-TR05	Transmission	Unattended	115.00	69.00	3.00	25.00	1				
374	PIPESTONE-TR06	Transmission	Unattended	115.00	69.00	14.00	25.00	1				
375	PLATO-TR01	Distribution	Unattended	115.00	12.50		15.00	1				
376	PRAIRIE ISLAND-TR10	Transmission	Unattended	345.00	161.00	14.00	224.00	1				
377	PRAIRIE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
378	PRAIRIE-TR03	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
379	PRAIRIE-TR05	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
380	PRAIRIE-TR07	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
381	PRAIRIE-TR08	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
382	PRIOR-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
383	QUARRY-TR09	Transmission	Unattended	345.00	115.00	35.00	448.00	1				
384	RAMSEY-TR01	Distribution	Unattended	115.00	13.80		50.00	1				
385	RAMSEY-TR02	Distribution	Unattended	115.00	13.80		50.00	1				
386	RED RIVER-TR01	Distribution	Unattended	115.00	23.00	14.00	91.00	1				
387	RED RIVER-TR02	Distribution	Unattended	115.00	23.00	14.00	91.00	1				
388	RED RIVER-TR03	Distribution	Unattended	115.00	23.00	5.00	91.00	1				
389	RED ROCK-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
390	RED ROCK-TR02	Distribution	Unattended	115.00	13.80		20.00	1				
391	RED ROCK-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
392	RED ROCK-TR05	Transmission	Unattended	345.00	230.00	14.00	336.00	1				
393	RED ROCK-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
394	RED ROCK-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
395	RED WING-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
396	RED WING-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
397	RENVILLE-TR01	Distribution	Unattended	69.00	12.50		7.00	1				

398	REYNOLDS-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
399	RICH SPRING-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
400	RICH VALLEY-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
401	RICHMOND-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
402	RIVERSIDE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
403	RIVERSIDE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
404	RIVERWOOD-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
405	RIVERWOOD-TR02	Distribution	Unattended	115.00	13.80		25.00	1				
406	ROCK RIVER-TR01	Distribution	Unattended	69.00	23.00		8.00	1				
407	ROGERS LAKE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
408	ROGERS LAKE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
409	ROSE PLACE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
410	ROSE PLACE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
411	ROSEMOUNT-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
412	SACRED HEART-TR01	Distribution	Unattended	69.00	13.80	4.00	5.00	1				
413	SALEM-TR01ABC	Distribution	Unattended	69.00	34.50	3.00	4.00	3				
414	SALEM-TR02	Distribution	Unattended	69.00	13.80		7.00	1				
415	SALIDA CROSSING-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
416	SALIDA CROSSING-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
417	SARTELL-TR01	Distribution	Unattended	34.50	12.50	2.00	7.00	1				
418	SAUK RIVER-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
419	SAUK RIVER-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
420	SAVAGE-TR01	Distribution	Unattended	115.00	13.80		25.00	1				
421	SAVAGE-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
422	SCANDIA-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
423	SCOTT COUNTY-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
424	SCOTT COUNTY-TR02	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
425	SCOTT COUNTY-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
426	SCOTT COUNTY-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
427	SEDAN-TR01 AB	Distribution	Unattended	69.00	7.20		0.30	1				
428	SHEAS LAKE-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
429	SHEAS LAKE-TR09	Transmission	Unattended	345.00	115.00	35.00	336.00	1				
430	SHEPARD-TR01	Distribution	Unattended	115.00	13.80		28.00	1				
431	SHEPARD-TR02	Distribution	Unattended	115.00	13.80		28.00	1				
432	SHERBURNE COUNTY-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
433	SHEYENNE-TR05	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
434	SHEYENNE-TR06	Transmission	Unattended	230.00	115.00	14.00	187.00	1				
435	SIBLEY PARK-TR01	Distribution	Unattended	69.00	13.80		28.00	1				
436	SIBLEY PARK-TR02	Distribution	Unattended	69.00	13.80		28.00	1				
437	SLAYTON WEST-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
438	SOURIS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				

439	SOURIS-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
440	SOURIS-TR03	Distribution	Unattended	115.00	13.80		52.50	1				
441	SOUTH BEND-TR05	Transmission	Unattended	115.00	69.00	14.00	46.70	1				
442	SOUTH BEND-TR06	Transmission	Unattended	161.00	115.00	14.00	187.00	1				
443	SOUTH HAVEN-TR01	Distribution	Unattended	69.00	34.50		1.00	1				
444	SOUTH RENNER-TR01	Distribution	Unattended	115.00	34.50		73.50	1				
445	SOUTH RIDGE-TR01	Distribution	Unattended	69.00	23.00		5.00	1				
446	SOUTH SIOUX FALLS-TR01	Distribution	Unattended	69.00	4.16		6.70	1				
447	SOUTH SIOUX FALLS-TR02	Distribution	Unattended	69.00	4.16		6.00	1				
448	SOUTH SIOUX FALLS-TR03	Distribution	Unattended	69.00	13.80		28.00	1				
449	SOUTH SIOUX FALLS-TR04	Distribution	Unattended	69.00	13.80		28.00	1				
450	SOUTHTOWN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
451	SOUTHTOWN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
452	SOUTHTOWN-TR03	Distribution	Unattended	115.00	13.80		62.50	1				
453	SOUTH-TR01ABC	Distribution	Unattended	69.00	2.40		1.00	3				
454	SPLIT ROCK-TR06	Transmission	Unattended	161.00	115.00	35.00	187.00	1				
455	SPLIT ROCK-TR07	Transmission	Unattended	230.00	115.00	14.00	336.00	1				
456	SPLIT ROCK-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
457	SPLIT ROCK-TR11	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
458	ST CLOUD-TR01	Distribution	Unattended	115.00	34.50		42.00	1				
459	ST CLOUD-TR02	Distribution	Unattended	115.00	34.50		42.00	1				
460	ST JAMES MUNICIPAL-TR01	Distribution	Unattended	69.00	12.50		14.00	1				
461	ST JOHNS-TR01	Distribution	Unattended	69.00	4.16		4.00	1				
462	ST JOSEPH-TR01	Distribution	Unattended	69.00	4.16		7.00	1				
463	ST LOUIS PARK-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
464	ST LOUIS PARK-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
465	ST LOUIS PARK-TR05	Distribution	Unattended	115.00	13.80		70.00	1				
466	ST LOUIS PARK-TR06	Distribution	Unattended	115.00	13.80		70.00	1				
467	ST. PAUL WATER-TR01	Distribution	Unattended	13.80	4.16		5.00	1				
468	STEWART-TR01	Distribution	Unattended	69.00	12.50		6.00	1				
469	STOCKYARDS-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
470	STOCKYARDS-TR02	Distribution	Unattended	118.00	13.80		46.70	1				
471	SUMMIT AVENUE-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
472	SUMMIT AVENUE-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
473	SWAN LAKE-TR01	Distribution	Unattended	115.00	12.50		10.50	1				
474	TANNERS LAKE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
475	TANNERS LAKE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
476	TANNERS LAKE-TR23A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
477	TANNERS LAKE-TR23A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
478	TANNERS LAKE-TR32A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
479	TANNERS LAKE-TR32A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				

480	TANNERS LAKE-TR34A1B1C1	Distribution	Unattended	13.80	12.50		10.00	3				
481	TANNERS LAKE-TR34A2B2C2	Distribution	Unattended	13.80	12.50		10.00	3				
482	TERMINAL-TR01	Distribution	Unattended	115.00	13.80		46.70	1				
483	TERMINAL-TR02	Distribution	Unattended	115.00	13.80		46.70	1				
484	TERMINAL-TR03	Distribution	Unattended	115.00	13.80		46.70	1				
485	TERMINAL-TR09	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
486	TERMINAL-TR10	Transmission	Unattended	345.00	115.00	35.00	672.00	1				
487	THOMPSON-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
488	TRACY SWITCHING-TR01	Distribution	Unattended	69.00	13.80		5.00	1				
489	TRACY-TR01	Distribution	Unattended	69.00	4.16	2.00	5.00	1				
490	TURTLE RIVER-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
491	TWIN LAKES-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
492	TWIN LAKES-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
493	TWIN LAKES-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
494	UPPER LEVEE-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
495	UPPER LEVEE-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
496	UPPER LEVEE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
497	VERMILLION RIVER-TR03	Distribution	Unattended	115.00	13.80		28.00	1				
498	VESELI-TR01	Distribution	Unattended	69.00	12.50		8.00	1				
499	VIKING-TR01	Distribution	Unattended	115.00	13.80		72.50	1				
500	VILLARD-TR01	Distribution	Unattended	69.00	12.50		3.00	1				
501	WABASHA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
502	WABASHA-TR02	Distribution	Unattended	69.00	2.40		20.00	1				
503	WACONIA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
504	WAKEFIELD-TR02	Distribution	Unattended	115.00	34.50	14.00	10.00	1				
505	WAKEFIELD-TR02ABC	Distribution	Unattended	34.50	13.80		2.00	3				
506	WAKEFIELD-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
507	WASECA-TR02	Distribution	Unattended	69.00	23.00		14.00	1				
508	WASECA-TR03	Distribution	Unattended	69.00	23.00		28.00	1				
509	WASECA-TR04	Distribution	Unattended	69.00	23.00		28.00	1				
510	WATAB RIVER-TR01	Distribution	Unattended	69.00	12.50		7.00	1				
511	WATERTOWN-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
512	WATERVILLE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
513	WATERVILLE-TR02	Distribution	Unattended	69.00	4.16		1.50	1				
514	WATERVILLE-TR03	Distribution	Unattended	69.00	12.50		3.50	1				
515	WATKINS-TR01	Distribution	Unattended	69.00	4.16		3.50	1				
516	WAVERLY-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
517	WELLS CREEK-TR01	Distribution	Unattended	69.00	12.50		5.00	1				
518	WESCOTT PROPANE PLANT-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
519	WEST BYRON-TR01	Distribution	Unattended	69.00	12.50		10.50	1				
520	WEST COON RAPIDS-TR01	Distribution	Unattended	115.00	34.50		70.00	1				

521	WEST COON RAPIDS-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
522	WEST COON RAPIDS-TR03	Distribution	Unattended	34.50	13.80		28.00	1				
523	WEST FARIBAULT-TR01	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
524	WEST FARIBAULT-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
525	WEST FARIBAULT-TR03	Distribution	Unattended	69.00	13.80		22.00	1				
526	WEST FARIBAULT-TR07	Distribution	Unattended	69.00	13.80		7.00	1				
527	WEST HASTINGS-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
528	WEST HASTINGS-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
529	WEST NEW ULM-TR05	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
530	WEST RIVER ROAD-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
531	WEST RIVER ROAD-TR02	Distribution	Unattended	115.00	13.80		72.50	1				
532	WEST RIVER ROAD-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
533	WEST SIOUX FALLS-TR05	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
534	WEST SIOUX FALLS-TR07	Distribution	Unattended	115.00	13.80		70.00	1				
535	WEST SIOUX FALLS-TR08	Distribution	Unattended	115.00	13.80		70.00	1				
536	WEST WACONIA-TR01	Distribution	Unattended	115.00	34.50		70.00	1				
537	WEST WACONIA-TR02	Distribution	Unattended	115.00	34.50		70.00	1				
538	WESTERN-TR01	Distribution	Unattended	115.00	13.80		70.00	1				
539	WESTERN-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
540	WESTGATE-TR01	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
541	WESTGATE-TR02	Transmission	Unattended	115.00	69.00	14.00	112.00	1				
542	WESTGATE-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
543	WESTGATE-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
544	WESTGATE-TR05	Distribution	Unattended	115.00	34.50		70.00	1				
545	WESTGATE-TR06	Distribution	Unattended	115.00	34.50		70.00	1				
546	WESTPORT-TR01X AB,Y CB	Distribution	Unattended	69.00	7.20		0.40	2				
547	WILMARTH-TR06	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
548	WILMARTH-TR07	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
549	WILMARTH-TR08	Transmission	Unattended	115.00	69.00	14.00	70.00	1				
550	WILMARTH-TR09	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
551	WILMARTH-TR10	Transmission	Unattended	345.00	115.00	14.00	448.00	1				
552	WILSON-TR02	Distribution	Unattended	115.00	13.80		70.00	1				
553	WILSON-TR03	Distribution	Unattended	115.00	13.80		70.00	1				
554	WILSON-TR04	Distribution	Unattended	115.00	13.80		70.00	1				
555	WILSON-TR05	Distribution	Unattended	115.00	13.80		70.00	1				
556	WINONA-TR01	Distribution	Unattended	69.00	13.80		22.00	1				
557	WINONA-TR02	Distribution	Unattended	69.00	13.80		22.00	1				
558	WINONA-TR03	Distribution	Unattended	69.00	13.80		25.00	1				
559	WINSTED-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
560	WINTHROP-TR01	Distribution	Unattended	69.00	4.16		6.25	1				
561	WOBEGON TRAIL-TR01	Distribution	Unattended	69.00	12.50		5.00	1				

562	WOODBURY-TR01	Distribution	Unattended	115.00	34.50		47.00	1				
563	WOODBURY-TR02	Distribution	Unattended	115.00	34.50		46.70	1				
564	WYOMING-TR01	Distribution	Unattended	115.00	12.50		28.00	1				
565	WYOMING-TR02	Distribution	Unattended	115.00	12.50		28.00	1				
566	YANKEE-TR01	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
567	YANKEE-TR02	Distribution	Unattended	115.00	34.50	14.00	120.00	1				
568	YELLOW MEDICINE-TR01	Distribution	Unattended	69.00	23.00		14.00	1				
569	YOUNG AMERICA-TR01	Distribution	Unattended	69.00	13.80		10.50	1				
570	YOUNG AMERICA-TR02	Distribution	Unattended	69.00	13.80		10.50	1				
571	ZUMBRO FALLS-TR01	Distribution	Unattended	69.00	12.50		4.00	1				
572	ZUMBROTA-TR01	Distribution	Unattended	69.00	13.80		14.00	1				
573	Total						44977	614	44			
574	Count TTL Transformer Banks							572				
575	Count TTL Transformers In Service							614				
576	TTL MVA In Service							44698				
577	Count TTL Substations with Transformers							307				
578	Count TTL Substations without Transformer							48				
579	Count TTL Substations							354				
580	Count TTL Spares							44				
581	Spare Transformers											
582	Alexandria-B67606			36	2		0		1			
583	Canistota Junc-2741803			23	13		5		1			
584	Chanarambie-T040N00142701			118	34		120		1			
585	Clarks Grove-8975520			69	8		2		1			
586	Emery sub-B67608			36	2		0		1			
587	Falls Sub-P660522			69	14		28		1			
588	Hazel Creek sub-10008553_C001			345	230	14	336		1			
589	Hugo Trg Ctr-242601941			118	14		14		1			
590	Inver Hills sub-10075845-001			345	115	35	672		1			
591	MGRV-TP80279701			345	165	14	336		1			
592	MGRV-8779073			345	118	35	448		1			
593	MGRV-WT02255			345	118	35	672		1			
594	MGRV-WT-03820			230	118	14	336		1			
595	MGRV-TP80240801			161	118	14	187		1			
596	MGRV-WT02258			118	71	14	112		1			
597	MGRV-13623/2			118			102		1			
598	MGRV-N2261			118	71	14	50		1			
599	MGRV-E5074			118	71	14	70		1			
600	MGRV-E4976			118	36		70		1			
601	MGRV-E4990			118	25		90		1			
602	MGRV-WTO4771			118	14		70		1			

603	MGRV-WTO4921			118	14		70		1			
604	MGRV-50939-1			118	14		47		1			
605	MGRV-N2219			118	34		70		1			
606	MGRV-91F0693			71	36		17		1			
607	MGRV-J9E1054			69	35		5		1			
608	MGRV-282210982			70	24		14		1			
609	MGRV-GT-3547			71	14		14		1			
610	MGRV-C184245			69	14		10		1			
611	MGRV-H881493			69	14		8		1			
612	MGRV-C0301051			69	14		7		1			
613	MGRV-1174820415			71	14		7		1			
614	MGRV-249834			69	14		4		1			
615	MGRV-249866			69	14		4		1			
616	MGRV-G852083B			69	12		4		1			
617	MGRV-9F1025			69	14		25		1			
618	MGRV-236578			69	13		4		1			
619	MGRV-6993529			69	4		10		1			
620	MGRV-47011MA014-D221A			69	14		14		1			
621	MGRV-4089204			14	4		5		1			
622	MGRV-N2264			69	13		7		1			
623	Portal Pipeline (Minot)-4088687			14	2		5		1			
624	Prairie Island-C0665551			345	20		866		1			
625	Red River-D590633			115	24		47		1			

Name of Respondent: Northern States Power Company (Minnesota)		This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Interchange agreement	Northern States Power Co. (a Wisconsin corporation)	see note	1 232,286,510
3	Repayments from Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	845,000,000
4	Services provided by Xcel Energy Services Inc.	Xcel Energy Services Inc.	see note	1 775,076,252
5	Contribution of Capital	Xcel Energy Inc.	211	656,892,793
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	1,402,000,000
7	Wind farm materials	Public Service Co of Colorado	see note	1 1,833,113
8	Company labor, benefits, and related payments	Northern States Power Co. (a Wisconsin corporation)	see note	1 531,398
9	Company labor, benefits, and related payments	Public Service Co of Colorado	see note	1 377,846
10	Solar farm materials (Capital Service procurement)	Capital Services LLC	107	58,266,491
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Interchange agreement	Northern States Power Co. (a Wisconsin corporation)	see note	1 482,200,770
22	Gas dispatch and SCADA system agreement	Northern States Power Co. (a Wisconsin corporation)	495	618,202
23	Vehicle and equipment use	Northern States Power Co. (a Wisconsin corporation)	see note	1 7,354,618
24	Company labor, benefits, and related payments	Northern States Power Co. (a Wisconsin corporation)	see note	1 23,018,792
25	Repayments under Utility Money Pool Arrangement	Xcel Energy Services Inc.	233	1,328,000,000
26	Investments in Utility Money Pool Arrangement	Xcel Energy Services Inc.	145	812,000,000
27	Dividends on Common Stock	Xcel Energy Inc.	216	418,098,125
28	Company labor, benefits, and related payments	Public Service Co. of Colorado	see note	1 297,939
29	Inventory Transfer	Northern States Power Co. (a Wisconsin corporation)	154	400,067
30	Inventory Transfer	Public Service Co. of Colorado	154	1,311,261
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Name of Respondent: Northern States Power Company (Minnesota)	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			
(a) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies			
557		\$	68,030,949
565			164,255,561
		\$	232,286,510
(b) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies			
Service Function Group	Updated FERC Group	Total	
Accounting, Financial Reporting & Taxes	107-CWIP	34,305,916	
	130-176-Current and Accrued Assets	45,773	
	181-190-Deferred Debits	4,090,920	
	252-283-Deferred Credits	209,386	
	408-409-Taxes	15,809,118	
	417-421-Other Income	(4,894,136)	
	426.1-426.5-Other Income Deductions	466,504	
	427-432-Interest Charges	48,983	
	500-514-Steam Power Generation	1,077,499	
	517-532-Nuclear Power Generation	301,759	
	535-545-Hydraulic Power Generation	3,700	
	546-557-Other Power Generation	1,796,797	
	558.13-558.24-Wind Generation	367,668	
	558.1-558.12-Solar Generation	13,868	
	559.1-559.16-Other Renewable Generation	27,173	
	560-573-Transmission Expenses	1,471,835	
	575.1-575.8-Regional Market Expenses	66,782	
	580-598-Distribution Expenses	1,146,693	
	725-742-Gas Raw Materials	242	
	800-813-Other Gas Supply Expenses	46,584	
	814-837-Underground Storage Expenses	26,500	
	840-843-Other Storage Expense	149,894	
	844-847-Liquified Natural Gas Terminating Expenses	2,496	
	850-870-Transmission Expenses	408,459	
	871-893-Distribution Expenses	210,319	
	901-905-Customer Accounts Expenses	2,115,764	
	908-910-Customer Service and Informational Expenses	79,800	
	911-916-Sales Expense	214,796	
	920-935-Administrative and General Expense	68,650,255	
Accounting, Financial Reporting & Taxes Total		128,261,347	
Aviation Services	426.1-426.5-Other Income Deductions	347	
	908-910-Customer Service and Informational Expenses	387	
	920-935-Administrative and General Expense	2,365,518	
Aviation Services Total		2,366,252	
Business Systems & Innovation	107-CWIP	157,669,816	
	130-176-Current and Accrued Assets	1,576	
	181-190-Deferred Debits	11,001	
	252-283-Deferred Credits	297	
	408-409-Taxes	(371)	
	417-421-Other Income	28	
	426.1-426.5-Other Income Deductions	39,474	
	500-514-Steam Power Generation	44,106	
	517-532-Nuclear Power Generation	2,604,607	
	535-545-Hydraulic Power Generation	160	
	546-557-Other Power Generation	2,961,088	
	558.13-558.24-Wind Generation	20,227	
	558.1-558.12-Solar Generation	261	
	559.1-559.16-Other Renewable Generation	859	
	560-573-Transmission Expenses	7,952,856	
	575.1-575.8-Regional Market Expenses	281,241	
	580-598-Distribution Expenses	5,290,932	
	725-742-Gas Raw Materials	34	
	800-813-Other Gas Supply Expenses	164,612	
	840-843-Other Storage Expense	51,516	

	844-847-Liquified Natural Gas Terminaling Expenses	265
	850-870-Transmission Expenses	26,776
	871-893-Distribution Expenses	546,328
	901-905-Customer Accounts Expenses	23,154,081
	908-910-Customer Service and Informational Expenses	98
	911-916-Sales Expense	421
	920-935-Administrative and General Expense	141,916,793
Business Systems & Innovation Total		342,739,082
Claims Services	920-935-Administrative and General Expense	579,589
Claims Services Total		579,589
Corporate Communications	181-190-Deferred Debits	2,616,031
	408-409-Taxes	83
	426.1-426.5-Other Income Deductions	3,320,858
	908-910-Customer Service and Informational Expenses	266,447
	911-916-Sales Expense	419
	920-935-Administrative and General Expense	4,581,375
Corporate Communications Total		10,785,213
Corporate Strategy & Business Development	426.1-426.5-Other Income Deductions	135,281
	911-916-Sales Expense	6,529
	920-935-Administrative and General Expense	3,511,075
Corporate Strategy & Business Development Total		3,652,885
Customer Service	107-CWIP	11,158
	181-190-Deferred Debits	1,182,392
	252-283-Deferred Credits	1,022,171
	417-421-Other Income	48,213
	426.1-426.5-Other Income Deductions	4,664
	580-598-Distribution Expenses	432
	850-870-Transmission Expenses	62
	901-905-Customer Accounts Expenses	15,831,430
	908-910-Customer Service and Informational Expenses	260,245
	911-916-Sales Expense	70,546
	920-935-Administrative and General Expense	46
Customer Service Total		18,431,359
Employee Communications	181-190-Deferred Debits	3,355
	908-910-Customer Service and Informational Expenses	20,425
	911-916-Sales Expense	(437)
	920-935-Administrative and General Expense	556,705
Employee Communications Total		580,048
Energy Delivery - Engineering/Design	107-CWIP	42,100,375
	130-176-Current and Accrued Assets	710,601
	181-190-Deferred Debits	4,850
	408-409-Taxes	286
	426.1-426.5-Other Income Deductions	65,214
	500-514-Steam Power Generation	84,811
	535-545-Hydraulic Power Generation	17,939
	546-557-Other Power Generation	1,309,836
	560-573-Transmission Expenses	5,101,348
	580-598-Distribution Expenses	2,455,959
	844-847-Liquified Natural Gas Terminaling Expenses	240
	850-870-Transmission Expenses	2,515,718
	870-893-Distribution Expenses	47
	871-893-Distribution Expenses	610,058
	920-935-Administrative and General Expense	1,553,077
Energy Delivery - Engineering/Design Total		56,530,359
Energy Delivery Construction, Operations & Maintenance (COM)	107-CWIP	233,762
	408-409-Taxes	437
	426.1-426.5-Other Income Deductions	17,186
	546-557-Other Power Generation	170,395
	560-573-Transmission Expenses	67,216
	580-598-Distribution Expenses	3,621,235
	814-837-Underground Storage Expenses	244,816
	840-843-Other Storage Expense	1,122,073
	850-870-Transmission Expenses	510,113
	871-893-Distribution Expenses	310,560
	901-905-Customer Accounts Expenses	(103)
	920-935-Administrative and General Expense	517,420
Energy Delivery Construction, Operations & Maintenance (COM) Total		6,815,110
Energy Markets - Fuel Procurement	426.1-426.5-Other Income Deductions	155
	500-514-Steam Power Generation	939,976
	559.1-559.16-Other Renewable Generation	8,355
	920-935-Administrative and General Expense	187,510
Energy Markets - Fuel Procurement Total		1,135,996
Energy Markets Regulated Trading & Marketing	426.1-426.5-Other Income Deductions	6,298
	546-557-Other Power Generation	2,893,518
	560-573-Transmission Expenses	438,106
	575.1-575.8-Regional Market Expenses	408,725
	800-813-Other Gas Supply Expenses	262,682
	920-935-Administrative and General Expense	1,216,824
Energy Markets Regulated Trading & Marketing Total		5,226,153
Energy Supply Business Resources	107-CWIP	2,453,458
	181-190-Deferred Debits	336,712
	426.1-426.5-Other Income Deductions	7,182
	500-514-Steam Power Generation	2,627,525

	517-532-Nuclear Power Generation	147,770
	535-545-Hydraulic Power Generation	5,476
	546-557-Other Power Generation	3,411,119
	558.13-558.24-Wind Generation	1,781,653
	558.1-558.12-Solar Generation	70,270
	559.1-559.16-Other Renewable Generation	38,475
	920-935-Administrative and General Expense	18,439
Energy Supply Business Resources Total		10,898,079
Environmental Services & System Planning	107-CWIP	16,527,660
	181-190-Deferred Debits	(128,376)
	426.1-426.5-Other Income Deductions	33,982
	500-514-Steam Power Generation	4,349,767
	517-532-Nuclear Power Generation	103,212
	535-545-Hydraulic Power Generation	15,430
	546-557-Other Power Generation	850,593
	558.13-558.24-Wind Generation	281,876
	559.1-559.16-Other Renewable Generation	66,084
	560-573-Transmission Expenses	28,809
	580-598-Distribution Expenses	81,195
	850-870-Transmission Expenses	243,364
	871-893-Distribution Expenses	219,519
	911-916-Sales Expense	2,881
	920-935-Administrative and General Expense	3,163,528
Environmental Services & System Planning Total		25,839,524
Executive Management Services	426.1-426.5-Other Income Deductions	1,390,837
	580-598-Distribution Expenses	3,019
	850-870-Transmission Expenses	96,825
	871-893-Distribution Expenses	4,136
	908-910-Customer Service and Informational Expenses	516
	920-935-Administrative and General Expense	5,245,136
Executive Management Services Total		6,740,469
Facilities & Real Estate	107-CWIP	3,425,301
	130-176-Current and Accrued Assets	8,845
	181-190-Deferred Debits	22,525
	252-283-Deferred Credits	394
	417-421-Other Income	24,408
	426.1-426.5-Other Income Deductions	41,649
	500-514-Steam Power Generation	1,720,818
	517-532-Nuclear Power Generation	9,189,471
	535-545-Hydraulic Power Generation	37,126
	546-557-Other Power Generation	1,828,618
	558.13-558.24-Wind Generation	143,945
	558.1-558.12-Solar Generation	5,309
	559.1-559.16-Other Renewable Generation	372,975
	560-573-Transmission Expenses	1,732,277
	575.1-575.8-Regional Market Expenses	25,513
	580-598-Distribution Expenses	4,563,997
	725-742-Gas Raw Materials	77
	800-813-Other Gas Supply Expenses	12,649
	814-837-Underground Storage Expenses	11,270
	840-843-Other Storage Expense	97,283
	844-847-Liquified Natural Gas Terminating Expenses	106,243
	850-870-Transmission Expenses	206,028
	871-893-Distribution Expenses	2,158,044
	901-905-Customer Accounts Expenses	316,502
	908-910-Customer Service and Informational Expenses	33,970
	911-916-Sales Expense	21,856
	920-935-Administrative and General Expense	14,861,707
Facilities & Real Estate Total		40,968,800
Finance & Treasury	107-CWIP	1,292,266
	181-190-Deferred Debits	3,882,500
	417-421-Other Income	(976,395)
	426.1-426.5-Other Income Deductions	466
	427-432-Interest Charges	6,647,825
	517-532-Nuclear Power Generation	170,924
	546-557-Other Power Generation	312,940
	920-935-Administrative and General Expense	22,100,338
Finance & Treasury Total		33,430,864
Fleet	107-CWIP	1,418,394
	130-176-Current and Accrued Assets	103
	181-190-Deferred Debits	27
	417-421-Other Income	4
	426.1-426.5-Other Income Deductions	2
	500-514-Steam Power Generation	21,876
	517-532-Nuclear Power Generation	8,706
	535-545-Hydraulic Power Generation	75
	546-557-Other Power Generation	1,013
	558.13-558.24-Wind Generation	4,615
	558.1-558.12-Solar Generation	289
	559.1-559.16-Other Renewable Generation	1,350
	560-573-Transmission Expenses	15,220
	575.1-575.8-Regional Market Expenses	4
	580-598-Distribution Expenses	153,856
	800-813-Other Gas Supply Expenses	2
	814-837-Underground Storage Expenses	2
	840-843-Other Storage Expense	17
	844-847-Liquified Natural Gas Terminating Expenses	1,048

	850-870-Transmission Expenses	42,444
	871-893-Distribution Expenses	24,955
	901-905-Customer Accounts Expenses	6,046
	908-910-Customer Service and Informational Expenses	26
	911-916-Sales Expense	16
	920-935-Administrative and General Expense	3,049
Fleet Total		1,703,139
Government Affairs	408-409-Taxes	329
	426.1-426.5-Other Income Deductions	795,976
	580-598-Distribution Expenses	1,713
	920-935-Administrative and General Expense	929,550
Government Affairs Total		1,727,568
Human Resources	107-CWIP	513,784
	130-176-Current and Accrued Assets	1,024
	181-190-Deferred Debits	12,466
	227-230-Other Noncurrent Liabilities	1,254,048
	231-245-Current and Accrued Liabilities	17,856,509
	252-283-Deferred Credits	294
	417-421-Other Income	49
	426.1-426.5-Other Income Deductions	42,908
	500-514-Steam Power Generation	2,735
	517-532-Nuclear Power Generation	474,135
	535-545-Hydraulic Power Generation	14
	546-557-Other Power Generation	1,160,605
	558.13-558.24-Wind Generation	10,394
	558.1-558.12-Solar Generation	562
	559.1-559.16-Other Renewable Generation	2,308
	560-573-Transmission Expenses	221,953
	575.1-575.8-Regional Market Expenses	1
	580-598-Distribution Expenses	413,279
	725-742-Gas Raw Materials	29
	800-813-Other Gas Supply Expenses	84
	840-843-Other Storage Expense	99
	844-847-Liquified Natural Gas Terminating Expenses	274
	850-870-Transmission Expenses	1,699
	871-893-Distribution Expenses	1,474
	901-905-Customer Accounts Expenses	4,328
	908-910-Customer Service and Informational Expenses	161,178
	911-916-Sales Expense	31,250
	920-935-Administrative and General Expense	13,883,465
Human Resources Total		36,050,948
Internal Audit	107-CWIP	6,803
	130-176-Current and Accrued Assets	8
	181-190-Deferred Debits	289
	426.1-426.5-Other Income Deductions	1,175
	500-514-Steam Power Generation	41
	517-532-Nuclear Power Generation	8,974
	535-545-Hydraulic Power Generation	1
	546-557-Other Power Generation	43
	558.13-558.24-Wind Generation	375
	558.1-558.12-Solar Generation	2
	559.1-559.16-Other Renewable Generation	22
	560-573-Transmission Expenses	38
	580-598-Distribution Expenses	226
	725-742-Gas Raw Materials	1
	844-847-Liquified Natural Gas Terminating Expenses	5
	850-870-Transmission Expenses	10
	871-893-Distribution Expenses	13
	901-905-Customer Accounts Expenses	23
	908-910-Customer Service and Informational Expenses	2
	911-916-Sales Expense	4
	920-935-Administrative and General Expense	1,245,857
Internal Audit Total		1,263,912
Investor Relations	426.1-426.5-Other Income Deductions	9
	920-935-Administrative and General Expense	854,620
Investor Relations Total		854,629
Legal	107-CWIP	187,510
	417-421-Other Income	1,000
	426.1-426.5-Other Income Deductions	2,606
	517-532-Nuclear Power Generation	87,364
	560-573-Transmission Expenses	58,531
	920-935-Administrative and General Expense	4,551,204
Legal Total		4,888,215
Marketing & Sales	107-CWIP	41,601
	130-176-Current and Accrued Assets	(68)
	181-190-Deferred Debits	10,319,524
	252-283-Deferred Credits	355,080
	408-409-Taxes	309
	417-421-Other Income	74,684
	426.1-426.5-Other Income Deductions	16,264
	546-557-Other Power Generation	(352)
	871-893-Distribution Expenses	3,811
	901-905-Customer Accounts Expenses	265,092
	908-910-Customer Service and Informational Expenses	642,894
	911-916-Sales Expense	2,539,060
	920-935-Administrative and General Expense	4,572,306
Marketing & Sales Total		18,830,205
Payment & Reporting	920-935-Administrative and General Expense	539,309

Payment & Reporting Total		539,309
Payroll	107-CWIP	616,168
	426.1-426.5-Other Income Deductions	130
	920-935-Administrative and General Expense	1,078,630
Payroll Total		1,694,928
Rates & Regulation	426.1-426.5-Other Income Deductions	1,524
	920-935-Administrative and General Expense	2,160,525
Rates & Regulation Total		2,162,049
Receipts Processing	901-905-Customer Accounts Expenses	10,552
	911-916-Sales Expense	59,763
	920-935-Administrative and General Expense	326,003
Receipts Processing Total		396,318
Supply Chain	107-CWIP	7,526,434
	130-176-Current and Accrued Assets	26,006
	181-190-Deferred Debits	179,014
	252-283-Deferred Credits	3,980
	417-421-Other Income	474
	426.1-426.5-Other Income Deductions	11,551
	500-514-Steam Power Generation	39,437
	517-532-Nuclear Power Generation	431,442
	535-545-Hydraulic Power Generation	397
	546-557-Other Power Generation	57,680
	558.13-558.24-Wind Generation	181,725
	558.1-558.12-Solar Generation	8,838
	559.1-559.16-Other Renewable Generation	21,222
	560-573-Transmission Expenses	59,633
	575.1-575.8-Regional Market Expenses	12
	580-598-Distribution Expenses	174,360
	725-742-Gas Raw Materials	483
	800-813-Other Gas Supply Expenses	1,299
	814-837-Underground Storage Expenses	5
	840-843-Other Storage Expense	1,714
	844-847-Liquified Natural Gas Terminaling Expenses	5,736
	850-870-Transmission Expenses	14,125
	871-893-Distribution Expenses	36,508
	901-905-Customer Accounts Expenses	63,208
	908-910-Customer Service and Informational Expenses	2,036
	911-916-Sales Expense	7,158
	920-935-Administrative and General Expense	(188,323)
Supply Chain Total		8,666,154
Wildfire Mitigation	107-CWIP	40,989
	426.1-426.5-Other Income Deductions	1,276
	560-573-Transmission Expenses	524,904
	580-598-Distribution Expenses	750,449
	920-935-Administrative and General Expense	131
Wildfire Mitigation Total		1,317,749
Grand Total		775,076,252

(c) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

107	\$1,385,716
108	215,017
232	232,380
	\$1,833,113

(d) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

(i) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

107	\$ 36,345
108	4,921
184	120,902
417.1	205
506	2,252
513	343
542	400
544	7,067
545	9,465
552	376
553	587
566	1,234
570	93
583	231
584	620
585	491
586	32,749
587	678
593	246
593	35,027
594	4
594	1,336
596	23
596	2,374
598	3,923
851	4,656
856	228
857	592
871	5,173
872	223
874	3,570
875	231
878	4,441
879	7,123
887	85
892	5,515
893	4,210
	\$ 297,939