414 Nicollet Mall
Minneapolis, Minnesota 55401

March 13, 2024

Via eTariff

The Honorable Debbie-Anne Reese
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Northern States Power Company, a Minnesota corporation and
Northern States Power Company, a Wisconsin corporation
Docket No. ER24-____-000
Interchange Agreement – Annual Update
Revised Tariff Pages Effective January 1, 2024

Dear Ms. Bose:

Pursuant to Federal Power Act Section 205, 16 U.S.C. § 824d, and Section 35.13 of the Rules and Regulations of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 35.13 (2023), Northern States Power Company, a Minnesota corporation ("NSPM") and Northern States Power Company, a Wisconsin corporation ("NSPW") (jointly the "NSP Companies"), submit revisions to the Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) (hereafter "Interchange Agreement" or "Agreement"). The revisions to the Interchange Agreement are submitted in accordance with Order No. 714[1] and the Commission's eTariff filing requirements.

Although the NSP Companies are filing revisions to all of the Exhibits to the Interchange Agreement to comply with the Commission's eTariff processes (since the Interchange Agreement has not been filed in section format), only the following Interchange Agreement exhibits are being restated or revised:

Exhibit I
Exhibit II
Exhibit III
Exhibit IV
Exhibit VI
Exhibit VII
Exhibit VIII
Exhibit IX

[1] *Electronic Tariff Filings,* Order No. 714, 124 FERC ¶ 61,270 (2008); *order on clarification*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

Pursuant to Section 14.2 of the Interchange Agreement, Exhibits VII, VIII, and IX are not subject to automatic adjustment and may only be changed by a Section 205 filing. In addition to required annual updates to Exhibits VII, VIII, and IX, the NSP Companies also propose modifications to Exhibits I, II, III, and IV to reflect new transmission loss multipliers based on a 2023 system loss study, and certain administrative tariff text modifications in Exhibits II, IV, and VI.

Marked versions of the complete Exhibit tariff pages showing the proposed revisions to the Interchange Agreement are included with this filing as an attachment in the XML package. The NSP Companies propose the revised tariff sheets be effective January 1, 2024, and respectfully request any waiver necessary for the tariff sheets to be effective on the date requested, so the NSP System cost allocations may be in effect for the full 2024 fiscal year.

A. Background

NSPM is an investor-owned Minnesota corporation engaged in, *inter alia*, the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Minnesota, North Dakota, and South Dakota. NSPW is an investor-owned Wisconsin corporation engaged in, *inter alia*, the business of generating, transmitting, distributing, and selling electric power and energy and related services in the States of Wisconsin and Michigan. The NSP Companies are both wholly owned utility operating company subsidiaries of Xcel Energy Inc. ("Xcel Energy"). The NSP Companies are transmission-owning members of the Midcontinent Independent System Operator, Inc. ("MISO"), and are market participants and use transmission services pursuant to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff") on file with and accepted by the Commission. Xcel Energy Services Inc. ("XES") is the centralized service company for the Xcel Energy holding company system and represents the Xcel Energy Operating Companies in proceedings before the Commission.[2]

The Interchange Agreement is a formula rate which provides for coordinated planning of the generation and transmission resources of the NSP Companies and the resulting charges between NSPM and NSPW for certain electric production and transmission costs related to the NSP Companies' integrated electric system (the "NSP System"). Pursuant to the terms of the Agreement, the NSP Companies annually restate or update certain exhibits to the Interchange Agreement.[3] The 2023 annual filing, which updated Exhibits I, II, III, IV, V, VI, VII, VIII and

[2] The other Xcel Energy Operating Companies are Public Service Company of Colorado and Southwestern Public Service Company.

[3] *See* Article XIV of the Interchange Agreement. In the 2001 annual filing, the NSP Companies restated the Interchange Agreement in its entirety effective January 1, 2001. The 2011 annual update, filed in Docket Nos. ER11-3234-000 and ER11-3235-000, submitted the Interchange Agreement in eTariff format. The Interchange Agreement was restated in eTariff format in Docket No. ER16-1429-000 to reflect implementation of new eTariff

IX and made certain other Exhibit revisions, was accepted effective January 1, 2023, by letter order dated May 9, 2023 in Docket No. ER23-1349-000.[4]

Neither of the NSP Companies serve any wholesale requirements production customers under rate schedules subject to Commission jurisdiction; rather, the NSP Companies serve only retail native load customers. As such, the Interchange Agreement solely affects the allocation of system costs between two affiliated and fully rate-regulated electric utilities for recovery in the retail rates of the NSP Companies.

B. Statement of Basis for Revised Tariff Sheets

As noted, the annual filing of revised Exhibits VII, VIII and IX is required by Article XIV of the Interchange Agreement which states:

> 14.2 Features Not Automatically Adjusting. It is the intent of the Parties that the values and data specified in Exhibits VII, VIII, IX and X shall not be subject to automatic adjustment and may be changed only by filing revised sheets as a rate change under the Federal Power Act. The Parties contemplate that a revised Exhibit VIII will be filed annually at the end of each calendar year to specify the projected average monthly peak demands for the succeeding calendar year, but that if the projected demands are not available before commencement of the calendar year to which they apply, they may be filed as soon in that calendar year as feasible, with a request, in which all Parties shall concur, that they be made effective as of the first day of the calendar year.

Section C of this transmittal letter (below) discusses the proposed revisions to the Interchange Agreement tariff pages in more detail. Also attached as parts of this filing are appendices providing various supporting schedules and information.

software by XES and the Xcel Energy Operating Companies. *See Northern States Power Company, a Minnesota corporation*, Docket No. ER16-1415-000 *et al*. (June 2, 2016) (delegated letter order).

[4] *See Northern States Power Company, a Minnesota corporation*, Docket No. ER23-1349-000 (May 9, 2023) (delegated letter order).

C. Proposed Revised Tariff Sheets Effective January 1, 2024

1. Exhibits I, II, III and IV – Updated Transmission Loss Multipliers

In Docket No. ER23-1349-000, the NSP Companies filed an electrical loss analysis which updated the demand and energy transmission loss ratios ("transmission loss multipliers") used in the Interchange Agreement for allocation of demand and energy between the NSP Companies.[5] As discussed in the Affidavit of Mr. Mark J. Wehlage filed with the 2018 annual update to the Interchange Agreement in Docket No. ER18-1117-000, the NSP Companies anticipated updating the loss ratios periodically.[6] At this time, the NSP Companies propose to revise the loss factors effective January 1, 2024 using the same methodology described in Docket No. ER23-1349-000. The current and proposed transmission loss factors are as follows:

	Current		Proposed	
Loss Ratios	NSPM	NSPW	NSPM	NSPW
Demand	3.8%	4.4%	4.0%	4.8%
Energy	3.9%	5.2%	4.1%	5.4%

The demand and energy transmission loss multipliers stated in the Interchange Agreement Exhibits are calculated by subtracting 1 minus the applicable loss ratio. For example, the new NSPW demand loss multiplier equals 1.0 minus 0.048, or 0.952. The current and revised transmission loss multipliers are:

	Current		Proposed	
Loss Multipliers	NSPM	NSPW	NSPM	NSPW
Demand	0.962	0.956	0.960	0.952
Energy	0.961	0.948	0.959	0.946

The loss ratios were developed using four years (2019 – 2022) of actual information collected from the NSP System energy management system and state estimator system. The proposed transmission loss ratios affect only the allocation of NSP System demand and energy costs between the NSP Companies, and do not affect the loss ratios applied by MISO for transmission services under the MISO Tariff. The impact of the proposed transmission loss multipliers is shown in Appendix A and discussed further in Section C.3 below. Appendix B is a copy of the updated loss study in support of the proposed transmission loss ratio and transmission loss multipliers.

[5] *See Northern States Power Company (Minnesota),* Interchange Agreement Annual Update, Docket No. ER23-1349-000, Transmittal Letter at 3-4 and App. B (filed Mar. 15, 2023).

[6] *See Northern States Power Company (Minnesota),* Interchange Agreement – Annual Update, Docket No. ER18-1117-000, Exhibit NSP-001 (filed Mar. 15, 2018).

2. Exhibits II, IV and VI – Administrative Tariff Text Modifications

In 2023, NSP-Minnesota transitioned retail customers in its Windsource program into Renewable*Connect Flex and terminated the Windsource program. Both programs provided retail customers in the state of Minnesota the option to buy electricity generated or purchased from renewable energy or energy generated by high-efficiency low-emissions distributed generation. Accordingly, the NSP Companies propose administrative tariff text changes to Exhibit II, Exhibit IV, and Exhibit VI, Schedule 3 to update the references to the Windsource program to the Renewable*Connect program.

3. Exhibit VIII – Specification of Average Monthly Peak Demands

Exhibit VIII sets forth the specification of average monthly coincident peak demands for calendar year 2024 for each of the NSP Companies.[7] These coincident peak demands were determined using the same methodology as the previous Exhibit VIII accepted in Docket No. ER23-1349-000 and prior annual updates. Coincident peak demands are based upon three years of data consisting of 18 months of actual and 18 months of projected peak demands.

Enclosed with this filing as Appendix A, Page 1 is the calculation of the 2024 36-month coincident peak demand ratios for each of the NSP Companies using the proposed loss multipliers.[8] These demand ratios are based on the average monthly coincident peak demands for calendar years 2022 – 2024 as set forth in Exhibit VIII. Appendix A, Page 2, is a statement of the financial impacts of these coincident peak demands on each of the NSP Companies, using the proposed loss multipliers. The table on the bottom of Appendix A, Page 2 quantifies the impact on the demand cost allocation of the proposed transmission loss multipliers compared to the current loss multipliers. While Appendix A provides support of certain calculations in the Interchange Agreement, it is not part of the Interchange Agreement and thus does not need to be filed in e-Tariff format.

4. Exhibit IX – Specification of Composite Depreciation Rates

Exhibit IX sets forth a specification of the composite depreciation rates currently approved for the NSP Companies by their respective state regulatory agencies. The modifications reflect, *inter alia*, changes in service lives, net salvage rates and mortality curves approved by the state regulatory bodies which have jurisdiction over NSPM and NSPW.[9]

[7] Monthly coincident peak demands are calculated to two decimal places and are rounded for purposes of display in Exhibit VIII and Attachment A, Page 1.

[8] Ibid.

[9] The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSPM and NSPW. Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSPM's

The Minnesota Public Utilities Commission ("MPUC"), the North Dakota Public Service Commission ("NDPSC") and the South Dakota Public Utilities Commission ("SDPUC") approved NSPM's currently effective depreciation rates in the following dockets:

- MPUC Docket No. 002/M-20-855, 2022-2024 Triennial Nuclear Decommissioning Study & Assumptions, order dated August 24, 2022;
- MPUC Docket No. E002/GR-21-630, Application for Authority to Increase Electric Rates, order dated July 17, 2023;
- MPUC Docket No. E,G002/D-22-299, 2022 Annual Review of Remaining Lives (ARL) and Depreciation Rates for Electric and Gas Production and Gas Storage Facilities (EGPS) & for Transmission, Distribution, and General Accounts (TDG) & Five-Year Transmission, Distribution, and General Depreciation Study, order dated January 9, 2024; and
- NDPSC Case No. PU-20-441, Application for Authority to Increase Rates for Electric Service in North Dakota, order dated August 18, 2021; and
- SDPUC Docket No. EL22-017, Application for Authority to Increase Electric Rates in South Dakota, settlement stipulation dated May 24, 2023, affirmed by the order dated June 8, 2023.

The Public Service Commission of Wisconsin ("PSCW") and the Michigan Public Service Commission ("MPSC") approved NSPW's currently effective depreciation rates in the following dockets:

- PSCW Docket No. 4220-DU-111, Approval of Adjustments to its Proposed Remaining Lives Depreciation and Revised Depreciation Rates for Test Years 2022-2023, order dated August 6, 2021; and
- PSCW Docket No. 4220-UR-125, Application for Authority to Adjust Electric and Natural Gas Rates in Wisconsin, order dated December 20, 2021; and
- MPSC Docket No. U-21121, Application for Recognition of Revised Depreciation Rates, order dated October 13, 2021.

As detailed in Section G below, the new, relevant initial filings and state Commission orders establishing revised depreciation rates for each of the NSP Companies are attached as Appendices D through J. Prior state depreciation petitions and orders referenced above were submitted to the Commission in Docket Nos. ER22-1234-000 and ER23-1349-000. The NSP

rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSPW's approved rates are the same for both the Wisconsin and Michigan jurisdictions. Even though individual depreciation lives may not have changed from the previous year, the depreciation rates in Exhibit IX are composite rates and a change in plant balances can cause a change in the rate by FERC Account.

Companies respectfully request that the Commission waive any requirement to refile the state regulatory depreciation orders previously filed with the Commission and available in eLibrary or eTariff.

Appendix A, Page 3 provides a statement of the impacts of the changes to depreciation rates on each of the NSP Companies.

5. Exhibit VII – Specification of Rate of Return on Common Equity

Exhibit VII sets forth a specification of the rate of return on common equity to determine the overall cost of capital. The NSP Companies are restating the existing Exhibit VII because the Commission has ceased to issue a quarterly adjusted generic rate of return on common equity. The NSP Companies only bear the burden of justifying an increase or decrease in the rate of return on common equity. Here, the NSP Companies are proposing no change to the rate of return on common equity for 2024 from the level accepted in Docket No. ER23-1349-000, so a statement of impact on each of the NSP Companies is not required.

D. Additional Information

1. Appendix C-1 – Benson Power Revenue Requirements

The Commission in February 2018 approved an application in Docket No. EC17-166-000 under which Benson Power, LLC ("Benson Power") would sell and NSPM would acquire a 62.3 MW (nameplate) biomass-fired electric generation plant, terminate a multi-year Power Purchase Agreement between NSPM and Benson Power, and then shut down and dismantle the Benson Power Facility and remediate the plant site (all collectively the "Benson Transaction").[10] On June 14, 2018, as supplemented on July 2, 2018, the NSP Companies filed modifications to certain exhibits in the Interchange Agreement to allow NSPM to allocate to NSPW and recover a share of the costs incurred by NSPM 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.[11]

As discussed in the Direct Testimony of Ms. Karen L. Everson, Exhibit No. NSP-001 ("Everson Testimony") in Docket No. ER18-1786-000, the NSP Companies proposed to include in the annual Interchange Agreement filing an appendix setting forth the annual Benson Power revenue requirement based on current project cost estimates.[12] As shown in Appendix C-1, the

[10] *Northern States Power Company, a Minnesota corporation et al.*, 162 FERC ¶ 61,162 (2018).

[11] *See Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin)*, Docket No. ER18-1786-000 (Aug. 10, 2018) (delegated letter order).

[12] *See Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin),* Interchange Agreement - Recovery of Benson Power Plant Termination Costs, Docket No. ER18-1786-000, Everson Testimony at 21 (June 14, 2018).

NSP Companies estimate that NSPM will bill NSPW approximately $2.0 million in revenue requirements in 2024, reflecting amortization expense of approximately $1.6 million and a cost of capital of 6.98 percent.

2. Appendix C-2 – Prairie Island Extended Power Uprate ("PI EPU") Revenue Requirements

Consistent with the Direct Testimony of Ms. Anne E. Heuer, Exhibit No. NSP-001 ("Heuer Testimony") in Docket No. ER15-698-000, the NSP Companies proposed to include in the annual Interchange Agreement filing an appendix calculating the current year annual revenue associated with the terminated PI EPU project.[13] As shown in Appendix C-2, the NSP Companies estimate that NSPM will bill NSPW approximately $0.6 million in revenue requirements in 2024.

3. Appendix C-3 – Acquisition Adjustments

In Docket No. ER20-1249-000 the NSP Companies filed modifications to certain exhibits in the Interchange Agreement to share plant acquisition adjustments between the two companies that are related to the production function. In that filing the NSP Companies proposed to include in the annual Interchange Agreement filing an appendix setting forth the acquisition adjustments that will be included in the formula. These modifications were accepted effective January 1, 2020, by letter order dated May 5, 2020 in Docket No. ER20-1249-000.[14] As shown in Appendix C-3, the NSP Companies anticipate inclusion of acquisition adjustments for three wind facilities in the billings from NSPM to NSPW in 2024, which is unchanged from 2023.

4. Order No. 898 Accounting and Reporting Treatment of Certain Renewable Energy Assets

On June 29, 2023 the Commission issued Order No. 898 in Docket No. RM21-11-000 amending the Uniform System of Accounts (USofA) for public utilities and licensees to: create new accounts for wind, solar, and other renewable generating assets; create a new functional class for energy storage accounts; codify the accounting treatment of environmental credits; and create new accounts within existing functions for computer hardware, software, and communication equipment.[15] The effective date of the order is January 1, 2025.

[13] *See Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin)*, Interchange Agreement – Prairie Island Extended Power Uprate Costs, Docket No. ER15-698-000, Exhibit No. NSP-001, Heuer Testimony at 19 (Dec. 22, 2014).

[14] *See Northern States Power Company, a Minnesota corporation*, Docket No. ER20-1249-000 (May 5, 2020) (delegated letter order).

[15] *Acct. & Reporting Treatment of Certain Renewable Energy Assets*, Order No. 898, 183 FERC ¶ 61,205 (2023).

The NSP Companies anticipate tariff changes to the Interchange Agreement to incorporate the new accounts created in Order No. 898. The NSP Companies plan to make a filing with the FERC in the second half of 2024 for the necessary modifications.

E. <u>E-Tariff Compliance</u>

NSPM is submitting the proposed tariff changes on behalf of the NSP Companies. As described in further detail in Docket Nos. ER11-3234-000 and ER11-3235-000, the NSP Companies selected NSPM as the party to submit the annual updates to the Interchange Agreement. NSPW's Certificate of Concurrence was filed in Docket No. ER11-3235-000.

F. <u>Request for Acceptance for Filing, Requests for Waiver</u>

The NSP Companies request the Commission accept the revised tariff sheets for filing effective January 1, 2024. The NSP Companies request a waiver of the Commission's notice requirements pursuant to 18 C.F.R. § 35.11, if necessary, as well as any other waivers which may be necessary for the revised tariff sheets to be accepted for filing effective on the date requested.[16]

In *Central Hudson Gas & Electric Corporation,*[17] the Commission stated that it would generally grant waivers of the 60-day prior notice requirement for uncontested filings that do not change rates. Based upon the above, a waiver is appropriate for this filing for the following reasons:

(1) The Interchange Agreement is a longstanding formula rate that only affects the allocation of system costs between two affiliated and fully rate-regulated electric utilities. In addition, neither of the NSP Companies serves any wholesale requirements customers whose rates would be affected by the changes proposed herein; and

(2) The Commission has regularly accepted the annual revisions to the Interchange Agreement effective January 1 of the filing year even though the revisions were not filed until sometime after January 1.

[16] *See Prior Notice and Filing Requirements under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 (1993) ("*Prior Notice")*, which states that a waiver of the 60-day notice period will be granted for certain amendments to pre-existing rate schedules. Among other things, *Prior Notice* indicates that waiver will be granted where the filing is unopposed or if the effective date of a rate change is prescribed by a contract on file with the Commission. *See id*. at 61,974-75. Here, section 14.2 of the Interchange Agreement, which is on file with the Commission, contemplates a January 1 effective date.

[17] 60 FERC ¶ 61,106 (1992), *reh'g denied.* 61 FERC¶ 61,089 (1992).

The NSP Companies also request that the Commission waive any requirement to refile depreciation supporting data, specifically state regulatory filings and orders affecting depreciation rates that have been previously filed with the Commission and are available in eLibrary. This information has already been filed with the Commission in Docket Nos. ER22-1234-000 and ER23-1349-000. The NSP Companies respectfully request that the Commission grant the waiver since the supporting information is available to staff and interested stakeholders through the Commission's eLibrary system.

G. Contents of Filing; Notice; Service

Pursuant to the Commission's filing requirements and in compliance with the e-Tariff Final Rule, the filing contains:

a. This transmittal letter;

b. The proposed revised Interchange Agreement Exhibits in clean format as an attachment in the XML package, with a January 1, 2024 effective date;

c. The proposed revised Interchange Agreement Exhibits in marked format, showing changes to the exhibits since they were accepted for filing in Docket No. ER23-1349-000; and

d. The following appendices:

   i. Appendix A, which sets forth the proposed 2024 36-month coincident peak demands, the financial impact of these proposed demands on each of the NSP Companies, and a statement of impact regarding depreciation rates on each of the NSP Companies;

   ii. Appendix B, a copy of the 2023 NSP System loss study supporting the proposed transmission loss ratios and the methodology used to calculate the proposed ratios;

   iii. Appendix C-1, which sets forth the 2024 Benson Power revenue requirement based on current project cost estimates, Appendix C-2, which sets forth the 2024 PI EPU revenue requirement, and Appendix C-3, which sets forth the production related acquisition adjustments based on current plant in-service dates;

   iv. Appendix D, the order issued July 17, 2023 in MPUC Docket No. E002/GR-21-630 approving the Application for Authority to Increase Rates for Electric Service in Minnesota;

   v. Appendix E, NSPM's direct testimony supporting depreciation rates filed in the Application for Authority to Increase Rates for Electric Service in Minnesota in MPUC Docket No. E002/GR-21-630

   vi. Appendix F, the order issued January 9, 2024 in MPUC Docket No. E,G002/D-22-299 approving NSPM's 2022 Annual Review of Remaining

Lives (ARL) and Depreciation Rates for Electric and Gas Production and Gas Storage Facilities (EGPS) & for Transmission, Distribution, and General Accounts (TDG) & Five-Year Transmission, Distribution, and General Depreciation Study

vii. Appendix G, NSPM's petition for approval of 2022 Annual Review of Remaining Lives (ARL) and Depreciation Rates for Electric and Gas Production and Gas Storage Facilities (EGPS) & for Transmission, Distribution, and General Accounts (TDG) & Five-Year Transmission, Distribution, and General Depreciation Study in MPUC Docket No. E,G002/D-22-299

viii. Appendix H, the order issued June 8, 2023 in SDPUC Docket No. EL22-017 in NSPM's approving Application for Authority to Increase Electric Rates in South Dakota,

ix. Appendix I, NSPM's direct testimony supporting depreciation rates filed in the Application for Authority to Increase Rates for Electric Service in South Dakota in SDPUC Docket No. EL22-017

x. Appendix J, the Service List for this filing.

A copy or electronic notice of this filing will be sent by e-mail to all State Commissions with jurisdiction over the NSP Companies (see Appendix J). The NSP Companies will also provide a courtesy copy of this filing to the Director, Division of Electric Power Regulation – Central. A copy of this filing will be available for public inspection at the offices of NSPM at 414 Nicollet Mall – 401—7th, Minneapolis, Minnesota; and NSPW's office at 1414 W. Hamilton Avenue, Eau Claire, Wisconsin.

H. Correspondence and Communications

Please send all communications and correspondence in this docket to:

Joseph W. Lowell
Assistant General Counsel
Xcel Energy Services Inc.
701 Pennsylvania Avenue NW, Suite 250
Washington, DC 20004
202-661-4491
joe.w.lowell@xcelenergy.com

Karen Everson
Director, Utility Accounting
Xcel Energy Services Inc.
1414 W. Hamilton Avenue, P.O. Box 8
Eau Claire, WI 54702-0008
715-737-2417
karen.l.everson@xcelenergy.com

For NSP-Minnesota:

Benjamin Halama
Manager, Revenue Analysis
Xcel Energy Services Inc.
414 Nicollet Mall – 401 7th Floor
Minneapolis, MN 55401
612-330-5703
benjamin.halama@xcelenergy.com

For NSP-Wisconsin:

Julie A. McRea
Director, Regulatory & Strategic Analysis
NSP-Wisconsin
1414 W. Hamilton Avenue, P.O. Box 8
Eau Claire, WI 54702-0008
715-737-2418
julie.a.mcrea@xcelenergy.com

I. Conclusion

The NSP Companies thus respectfully request the Commission accept the revised tariff sheets to the Interchange Agreement for filing effective January 1, 2024. Please direct any questions regarding this filing to the undersigned (715-737-2417) or Mr. Joseph W. Lowell (202-661-4491).

Sincerely,

/s/ *Karen L. Everson*

Karen L. Everson
Director, Utility Accounting
Xcel Energy Services Inc., on behalf of
Northern States Power Company, a Minnesota corporation and
Northern States Power Company, a Wisconsin corporation

Enclosures

Exhibits

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit I**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.~~962~~ 960 for NSP(Minn)
0.~~956~~ 952 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit II**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes. [1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.~~961~~ 959 for NSP(Minn)
0.~~948~~ 946 for NSP(Wis)

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

[1/] Including, but not limited to, the NSP (Minn) ~~Windsource®~~Renewable*Connect program.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit III

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.~~962~~ 960 for NSP(Minn)
0.~~956~~ 952 for NSP(Wis)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IV**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the current month excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.~~961~~ 959 for NSP(Minn)
0.~~948~~ 946 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) ~~Windsource®~~ Renewable*Connect program.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit V**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Add: Electric Construction Work in Progress (Sched. 4.1)		
6.1	Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)		
7.	Rate Base (Total lines 1 through 6.1)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through 18)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit V**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines 20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, 19 and 22)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 1

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. Electric Plant in Service balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 1.1

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midcontinent Independent System Operator, Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.2

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111. Accumulated Provision for Depreciation balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

These accounts are classified to the intangible, production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2.1

ACCUMULATED PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 3

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the intangible, production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service. Accumulated Deferred Income Tax balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4.1

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midcontinent Independent System Operator, Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3 in accordance with the Minnesota Public Utilities Commission (MPUC) decision (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
Functional Class	**Total NSP (Minn) Actual to Theoretical Reserve Difference**	**NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference**	**NSP (Wis) Actual to Theoretical Reserve Difference**
Intangible 1/	$417,044	$365,054	$0
Transmission	200,466,880	149,597,398	26,645,321
Distribution 2/	109,362,353	109,362,353	18,051
General	6,727,378	5,888,716	10,899
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271

Notes:

1/ No Intangible reserve to NSP (Wis).
2/ Distribution reserve difference included under “NSP (Wis) Actual to Theoretical Reserve Difference” relates to Distribution serving system generation.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 5

OTHER

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule 6 and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year, or such date after January 1 determined by the Coordinating Committee, either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of such year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year of the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1. Required Return on Rate Base (Schedule 6)
2. Add: Book Depreciation and Amortization (Schedule 8)
3. Provision for Deferred Income Taxes (Schedule 9)
4. Deduct: Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
4.1 Production Tax Credit (Schedule 7, Page 3 of 3)
5. Income Tax Depreciation (Schedule 7, Page 3 of 3)
6. Interest Expense (Schedule 7, Page 3 of 3)
7. Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)

8. Income Tax Base

9. Preliminary Income Taxes @ Income Tax Conversion Factor (1)

10. Deduct: Investment Tax Credit Flow Through (Line 4)
10.1 Production Tax Credit (Line 4.1)
11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\frac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let:
F = Federal Income Tax Rate
M = Minnesota State Income Tax Rate
D = North Dakota State Income Tax Rate
S = South Dakota State Income Tax Rate
W = Wisconsin State Income Tax Rate
MI = Michigan State Single Business Tax Rate
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = ______________ (N)
F = ______________ (N)
M + F = _______________ (N)

Only North Dakota and Federal Income Taxes:
F = ______________ (N)
D = ______________ (N)
F + D = _______________ (N)

Only South Dakota and Federal Income Taxes:
S + F = _______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = _______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes
W = ______________ (N)
MI = ______________ (N)
F = ______________ (N)
W +MI+ F = _______________ (N)

Notes:
1. Investment Tax Credit, Production Tax Credit, and Surtax Credits are ignored in all formulas.

2. State Income Taxes are deductible from Federal Taxable Income.
Federal Income Tax is deductible from North Dakota Taxable Income.
Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Production Tax Credit

The Production Tax Credit is recorded in FERC Account 409.1. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production function. Production Tax Credit will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized. Income Tax Depreciation will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407. Depreciation and amortization expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.3

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 8.4

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC ("Benson Power") biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the "Total Actual Benson Power Termination Costs"). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility ("Benson Power Termination Costs").

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)'s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 9

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment. Provision for Deferred Income Taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 10

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment. The Property Tax expense or taxes in lieu of property taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 11

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities. Insurance Expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X. Fixed Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12.1

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 13

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 14

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 15

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 16**

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 17

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VI**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

	NSP (Minn)	NSP(Wis)
1. Fuel Expenses (Schedule 1)		
2. Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)		
3. Net Purchased Power Energy Costs (Schedule 3)		
4. Carrying Cost on Fuel Stocks		
4.1 Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs		
5. Total Energy Related Costs (Total lines 1 through 4.1)		

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 1

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X. Variable Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI Schedule 2.1

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power and FERC Account 555.1 – Power Purchased for Energy Storage Operations. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) ~~Windsource®~~ Renewable*Connect program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price ("LMP") from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VII**

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 10.40%.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VIII**

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year ~~2023~~ 2024 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
~~2021~~2022	January	5,352~~4,838~~	1,071~~1,024~~	6,423~~5,862~~
	February	5,194~~5,126~~	1,016~~1,096~~	6,210~~6,222~~
	March	4,798~~4,576~~	965~~981~~	5,763~~5,557~~
	April	4,628~~4,465~~	938~~837~~	5,566~~5,302~~
	May	5,607~~5,862~~	1,125~~1,057~~	6,732~~6,919~~
	June	7,883~~7,507~~	1,362~~1,330~~	9,245~~8,837~~
	July	7,686~~7,546~~	1,323~~1,214~~	9,008~~8,760~~
	August	7,446~~7,216~~	1,318~~1,232~~	8,765~~8,448~~
	September	6,857~~6,008~~	1,232~~996~~	8,089~~7,004~~
	October	4,661~~5,119~~	936~~992~~	5,597~~6,111~~
	November	4,748~~4,643~~	1,062~~950~~	5,810~~5,593~~
	December	5,325~~5,108~~	1,128~~1,061~~	6,453~~6,169~~
	Total	70,185~~68,014~~	13,476~~12,770~~	83,661~~80,784~~
~~2022~~2023	January	5,079~~5,352~~	1,092~~1,071~~	6,171~~6,423~~
	February	5,056~~5,194~~	1,077~~1,016~~	6,133~~6,210~~
	March	4,671~~4,798~~	1,001~~965~~	5,672~~5,763~~
	April	5,115~~4,628~~	941~~938~~	6,056~~5,566~~
	May	6,389~~5,607~~	1,152~~1,125~~	7,541~~6,732~~
	June	6,796~~7,883~~	1,205~~1,362~~	8,001~~9,245~~
	July	7,219~~7,131~~	1,264~~1,319~~	8,483~~8,450~~
	August	7,227~~7,173~~	1,258~~1,277~~	8,485~~8,450~~
	September	6,292~~6,351~~	1,113~~1,126~~	7,405~~7,477~~
	October	4,703~~4,688~~	919~~978~~	5,622~~5,666~~
	November	4,771~~4,793~~	1,070~~991~~	5,841~~5,784~~
	December	5,297~~5,188~~	1,125~~1,109~~	6,423~~6,297~~
	Total	68,615~~68,786~~	13,216~~13,277~~	81,831~~82,063~~
~~2023~~2024	January	5,357~~5,207~~	1,122~~1,121~~	6,479~~6,328~~
	February	4,968~~4,980~~	1,068~~1,086~~	6,036~~6,066~~
	March	4,795~~4,741~~	1,055~~1,042~~	5,850~~5,783~~
	April	4,383~~4,379~~	840~~881~~	5,223~~5,260~~
	May	5,648~~5,449~~	1,072~~1,071~~	6,720~~6,520~~
	June	6,922~~7,105~~	1,341~~1,312~~	8,263~~8,417~~
	July	7,250~~7,142~~	1,280~~1,344~~	8,530~~8,486~~
	August	7,275~~7,189~~	1,256~~1,297~~	8,531~~8,486~~
	September	6,238~~6,304~~	1,101~~1,140~~	7,339~~7,444~~
	October	4,670~~4,619~~	904~~978~~	5,574~~5,597~~
	November	4,735~~4,710~~	1,063~~993~~	5,798~~5,703~~
	December	5,263~~5,134~~	1,142~~1,102~~	6,405~~6,236~~
	Total	67,505~~66,959~~	13,244~~13,367~~	80,749~~80,326~~

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2023~~ 2024 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	~~4.68~~5.09%
E312	STEAM	Boiler Plant Equipment	~~3.86~~4.70%
E314	STEAM	Turbogenerator Units	~~3.48~~4.55%
E315	STEAM	Accessory Electric Equipment	~~3.68~~4.04%
E316	STEAM	Miscellaneous Power Plant Equipment	~~4.23~~4.43%
E302	NUCLEAR	Franchises & Consents	~~5.45~~3.98%
E321	NUCLEAR	Structures and Improvements	~~4.98~~3.73%
E322	NUCLEAR	Reactor Plant Equipment	~~4.41~~3.57%
E323	NUCLEAR	Turbogenerator Units	~~3.85~~2.98%
E324	NUCLEAR	Accessory Electric Equipment	~~4.50~~3.63%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	~~4.97~~3.96%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	~~6.99~~7.15%
E332	HYDRO	Reservoirs, Dams and Waterways	~~5.54~~5.65%
E333	HYDRO	Water Wheels, Turbines & Generators	~~5.73~~6.11%
E334	HYDRO	Accessory Electric Equipment	~~5.96~~6.29%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~5.45~~4.03%
E336	HYDRO	Roads, Railroads and Bridges	~~1.76~~2.62%
E340.1	OTHER	Wind Rights	~~2.61~~2.42%
E341	OTHER	Structures and Improvements	~~4.02~~3.07%
E342	OTHER	Fuel Holders, Producers & Accessories	~~4.71~~4.53%
E343	OTHER	Prime Movers	~~3.58~~3.90%
E344	OTHER	Generators	~~4.36~~3.92%
E345	OTHER	Accessory Electric Equipment	~~4.24~~2.90%
E346	OTHER	Miscellaneous Power Plant Equipment	~~5.19~~4.70%
E348	OTHER	Energy Storage Equipment – Production	0.00%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	~~1.50~~1.74%
*E352	Structures and Improvements-Prod.	~~1.50~~1.74%
E353	Station Equipment	~~2.05~~2.15%
*E353	Station Equipment-Prod.	~~2.05~~2.15%
E354	Towers and Fixtures	~~1.77~~2.04%
*E354	Towers and Fixtures-Prod.	~~1.77~~2.04%
E355	Poles and Fixtures	~~2.40~~2.56%
*E355	Poles and Fixtures-Prod.	~~2.40~~2.56%
E356	Overhead Conductors & Devices	~~2.03~~2.09%
*E356	Overhead Conductors & Devices-Prod.	~~2.03~~2.09%
E357	Underground Conduit	~~1.36~~1.42%
E358	Underground Conductors & Devices	~~2.07~~2.11%
DISTRIBUTION		
E361	Structures and Improvements	~~2.08~~2.26%
*E361	Structures and Improvements-Prod.	~~2.09~~2.29%
E362	Station Equipment	~~2.32~~2.61%
*E362	Station Equipment-Prod.	~~2.34~~2.65%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	~~4.59~~5.38%
E365	Overhead Conductors and Devices	~~3.19~~3.54%
E366	Underground Conduit	~~2.13~~1.99%
E367	Underground Conductor and Devices	~~2.21~~2.41%
E368	Line Transformers	~~3.26~~3.44%
E368	Line Capacitors	~~3.97~~4.53%
E369	Overhead Services	~~4.28~~5.00%
E369	Underground Services	~~2.36~~2.58%
E370	Meters	~~6.27~~6.89%
E370.2	AGIS Meters	5.02%
E370.3	Electric Vehicle Chargers	~~10.00~~10.33%
E373	Street Lighting and Signal Systems	~~5.65~~5.24%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

GENERAL - ELECTRIC

E302	Franchises & Consents	~~4.97~~4.91%
E303	Intangible Plant – 5 Year	~~19.53~~20.48%
E303	Intangible Plant – 10 Year	~~10.31~~10.06%
E390	Structures and Improvements	~~1.88~~1.89%
E391	Office Furniture and Equipment	~~4.87~~4.90%
E391	Network Equipment	~~17.51~~16.89%
E392	Transportation Equipment – Auto	~~9.75~~9.35%
E392	Transportation Equipment – Light Truck	~~9.81~~8.67%
E392	Transportation Equipment – Trailers	~~6.28~~6.91%
E392	Transportation Equipment – Heavy Trucks	~~7.13~~7.32%
E393	Stores Equipment	~~4.55~~4.86%
E394	Tools, Shop and Garage Equipment	6.58%
E395	Laboratory Equipment	~~10.62~~9.77%
E396	Power Operated Equipment	~~5.53~~6.27%
E397	Communication Equipment – General	~~10.45~~10.03%
E397	Communication Equipment – Two Way	~~10.38~~9.94%
E397	Communication Equipment – AMR	~~5.02~~6.37%
*E397	Communication Equipment – EMS	~~6.29~~6.58%
E397	Communication Equipment – Smart Grid	~~5.68~~5.35%
E398	Miscellaneous Equipment	~~6.80~~6.60%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	~~2023~~ 2024 Approved Accrual	Docket No./Case No.
Minnesota Retail	$21,571,110	E002/M-20-855
North Dakota Retail	$2,250,002	PU-20-441
South Dakota Retail	$~~1,234,251~~2,769,552	~~EL14-058~~EL22-017
Wisconsin Retail	$9,300,~~588~~587	E002/M-20-855 4220-UR-~~125~~126

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES ~~2023~~ 2024 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	~~5.63~~6.17%
E312	STEAM	Boiler Plant Equipment	~~4.82~~5.31%
E314	STEAM	Turbogenerator Units	~~4.44~~4.40%
E315	STEAM	Accessory Electric Equipment	~~6.01~~6.92%
E316	STEAM	Miscellaneous Power Plant Equipment	~~3.78~~4.27%
E302	HYDRO	Franchises & Consents	~~1.48~~1.46%
E331	HYDRO	Structures and Improvements	~~3.43~~3.57%
E332	HYDRO	Reservoirs, Dams and Waterways	~~4.11~~4.20%
E333	HYDRO	Water Wheels, Turbines & Generators	~~4.57~~4.85%
E334	HYDRO	Accessory Electric Equipment	~~5.26~~5.58%
E335	HYDRO	Miscellaneous Power Plant Equipment	~~4.65~~5.04%
E341	OTHER	Structures and Improvements	~~3.77~~5.05%
E342	OTHER	Fuel Holders, Producers & Accessories	~~3.84~~4.24%
E343	OTHER	Prime Movers	~~4.38~~5.06%
E344	OTHER	Generators	~~4.53~~5.57%
E345	OTHER	Accessory Electric Equipment	~~4.65~~5.73%
E346	OTHER	Miscellaneous Power Plant Equipment	~~2.08~~2.93%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.09%
*E352		Structures and Improvements-Prod.	2.09%
E353		Station Equipment	2.80%
*E353		Station Equipment-Prod.	2.80%
E354		Towers and Fixtures	1.80%
E355		Poles and Fixtures	3.28%
E356		Overhead Conductors & Devices	2.80%
E357		Underground Conduit	1.76%
E358		Underground Conductors & Devices	2.77%
E359		Roads and Trails	1.75%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

DISTRIBUTION

E361	Structures and Improvements	2.03%
*E361	Structures and Improvements – Prod.	2.03%
E362	Station Equipment	2.51%
*362	Station Equipment – Prod.	2.51%
E363	Energy Storage Equipment – Distribution	10.00%
E364	Poles, Towers and Fixtures	5.26%
E365	Overhead Conductors and Devices	3.51%
E366	Underground Conduit	1.62%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	2.28%
E368	Line Capacitors	2.66%
E369	Overhead Services	3.61%
E369	Underground Services	2.73%
E370	Meters	4.54%
E370.1	Meters – Old	0.00%
E370.2	AGIS Meters	5.00%
E370.~~2~~6	Meters – AMR	4.84%
E371	Customer Installations	0.00%
E371.4	Installations on Customer’s Premises-EV	10.00%
E371.5	Customer Prem-REMS	3.33%
E373	Street Lighting and Signal Systems	5.72%

GENERAL ELECTRIC

E302	Franchises & Consents	5.00%
E303	Intangible Plant – 3 Year	33.33%
E303	Intangible Plant – 5 Year	25.98%
E303	Intangible Plant – 7 Year	14.29%
E303	Intangible Plant – 10 Year	10.00%
E303	Intangible Plant – 15 Year	~~6.67~~6.76%
E390	Structures and Improvements	2.17%
E391	Office Furniture and Equipment	4.57%
E391	Network Equipment	18.83%
E392	Transportation Equipment – Auto	12.67%
E392	Transportation Equipment – Light Truck	12.38%
E392	Transportation Equipment – Trailers	5.62%
E392	Transportation Equipment – Heavy Truck	8.21%
E393	Stores Equipment	4.45%
E394	Tools, Shop and Garage Equipment	4.80%
E395	Laboratory Equipment	3.45%
E396	Power Operated Equipment	5.96%
E397	Communication Equipment – AES/AMR	6.11%
*E397	Communication Equipment – EMS	6.11%
E398	Miscellaneous Equipment	4.48%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit X

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant	X	

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit X

SPECIFICATIONS OF DEMAND AND ENERGY CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
548.1	Operation of energy storage equipment	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

Exhibits

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit I

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.960 for NSP(Minn)
0.952 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit II**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes. [1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.959 for NSP(Minn)
0.946 for NSP(Wis)

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

[1/] Including, but not limited to, the NSP (Minn) Renewable*Connect program.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit III**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.960 for NSP(Minn)
0.952 for NSP(Wis)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit IV

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the current month excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.959 for NSP(Minn)
0.946 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Renewable*Connect program.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit V**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Add: Electric Construction Work in Progress (Sched. 4.1)		
6.1	Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)		
7.	Rate Base (Total lines 1 through 6.1)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through 18)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit V**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines 20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, 19 and 22)

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. Electric Plant in Service balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 1.1

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midcontinent Independent System Operator, Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.2

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 2

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111. Accumulated Provision for Depreciation balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

These accounts are classified to the intangible, production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2.1

ACCUMULATED PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 3

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the intangible, production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service. Accumulated Deferred Income Tax balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4.1

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midcontinent Independent System Operator, Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4.2

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3 in accordance with the Minnesota Public Utilities Commission (MPUC) decision (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
Functional Class	**Total NSP (Minn) Actual to Theoretical Reserve Difference**	**NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference**	**NSP (Wis) Actual to Theoretical Reserve Difference**
Intangible 1/	$417,044	$365,054	$0
Transmission	200,466,880	149,597,398	26,645,321
Distribution 2/	109,362,353	109,362,353	18,051
General	6,727,378	5,888,716	10,899
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271

Notes:

1/ No Intangible reserve to NSP (Wis).
2/ Distribution reserve difference included under “NSP (Wis) Actual to Theoretical Reserve Difference” relates to Distribution serving system generation.

OTHER

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 6

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule 6 and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year, or such date after January 1 determined by the Coordinating Committee, either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of such year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year of the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1.	Required Return on Rate Base (Schedule 6)	
2.	Add:	Book Depreciation and Amortization (Schedule 8)
3.		Provision for Deferred Income Taxes (Schedule 9)
4.	Deduct:	Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
4.1		Production Tax Credit (Schedule 7, Page 3 of 3)
5.		Income Tax Depreciation (Schedule 7, Page 3 of 3)
6.		Interest Expense (Schedule 7, Page 3 of 3)
7.		Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)
8.	Income Tax Base	
9.	Preliminary Income Taxes @ Income Tax Conversion Factor (1)	
10.	Deduct:	Investment Tax Credit Flow Through (Line 4)
10.1		Production Tax Credit (Line 4.1)
11.	Preferred Dividend Credit (Line 7)	
12.	Federal and State Income Taxes	

(1) $\dfrac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let:
F = Federal Income Tax Rate
M = Minnesota State Income Tax Rate
D = North Dakota State Income Tax Rate
S = South Dakota State Income Tax Rate
W = Wisconsin State Income Tax Rate
MI = Michigan State Single Business Tax Rate
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = _____________ (N)
F = _____________ (N)
M + F = ______________ (N)

Only North Dakota and Federal Income Taxes:
F = _____________ (N)
D = _____________ (N)
F + D = ______________ (N)

Only South Dakota and Federal Income Taxes:
S + F = ______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = ______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes
W = _____________ (N)
MI = _____________ (N)
F = _____________ (N)
W +MI+ F = ______________ (N)

Notes:
1. Investment Tax Credit, Production Tax Credit, and Surtax Credits are ignored in all formulas.
2. State Income Taxes are deductible from Federal Taxable Income.
Federal Income Tax is deductible from North Dakota Taxable Income.
Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Production Tax Credit

The Production Tax Credit is recorded in FERC Account 409.1. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production function. Production Tax Credit will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized. Income Tax Depreciation will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407. Depreciation and amortization expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 8.2

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.3

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT
RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC ("Benson Power") biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the "Total Actual Benson Power Termination Costs"). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility ("Benson Power Termination Costs").

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)'s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 9

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment. Provision for Deferred Income Taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 10

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment. The Property Tax expense or taxes in lieu of property taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 11

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities. Insurance Expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X. Fixed Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12.1

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 13

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 14

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 15

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 16

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 17

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VI**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

	NSP (Minn)	NSP(Wis)
1. Fuel Expenses (Schedule 1)		
2. Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)		
3. Net Purchased Power Energy Costs (Schedule 3)		
4. Carrying Cost on Fuel Stocks		
4.1 Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs		
5. Total Energy Related Costs (Total lines 1 through 4.1)		

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 1

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X. Variable Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2.1

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power and FERC Account 555.1 – Power Purchased for Energy Storage Operations. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Renewable*Connect program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price ("LMP") from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VII**

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 10.40%.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VIII

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2024 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
2022	January	5,352	1,071	6,423
	February	5,194	1,016	6,210
	March	4,798	965	5,763
	April	4,628	938	5,566
	May	5,607	1,125	6,732
	June	7,883	1,362	9,245
	July	7,686	1,323	9,008
	August	7,446	1,318	8,765
	September	6,857	1,232	8,089
	October	4,661	936	5,597
	November	4,748	1,062	5,810
	December	5,325	1,128	6,453
	Total	70,185	13,476	83,661
2023	January	5,079	1,092	6,171
	February	5,056	1,077	6,133
	March	4,671	1,001	5,672
	April	5,115	941	6,056
	May	6,389	1,152	7,541
	June	6,796	1,205	8,001
	July	7,219	1,264	8,483
	August	7,227	1,258	8,485
	September	6,292	1,113	7,405
	October	4,703	919	5,622
	November	4,771	1,070	5,841
	December	5,297	1,125	6,423
	Total	68,615	13,216	81,831
2024	January	5,357	1,122	6,479
	February	4,968	1,068	6,036
	March	4,795	1,055	5,850
	April	4,383	840	5,223
	May	5,648	1,072	6,720
	June	6,922	1,341	8,263
	July	7,250	1,280	8,530
	August	7,275	1,256	8,531
	September	6,238	1,101	7,339
	October	4,670	904	5,574
	November	4,735	1,063	5,798
	December	5,263	1,142	6,405
	Total	67,505	13,244	80,749

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2024 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	5.09%
E312	STEAM	Boiler Plant Equipment	4.70%
E314	STEAM	Turbogenerator Units	4.55%
E315	STEAM	Accessory Electric Equipment	4.04%
E316	STEAM	Miscellaneous Power Plant Equipment	4.43%
E302	NUCLEAR	Franchises & Consents	3.98%
E321	NUCLEAR	Structures and Improvements	3.73%
E322	NUCLEAR	Reactor Plant Equipment	3.57%
E323	NUCLEAR	Turbogenerator Units	2.98%
E324	NUCLEAR	Accessory Electric Equipment	3.63%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	3.96%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	7.15%
E332	HYDRO	Reservoirs, Dams and Waterways	5.65%
E333	HYDRO	Water Wheels, Turbines & Generators	6.11%
E334	HYDRO	Accessory Electric Equipment	6.29%
E335	HYDRO	Miscellaneous Power Plant Equipment	4.03%
E336	HYDRO	Roads, Railroads and Bridges	2.62%
E340.1	OTHER	Wind Rights	2.42%
E341	OTHER	Structures and Improvements	3.07%
E342	OTHER	Fuel Holders, Producers & Accessories	4.53%
E343	OTHER	Prime Movers	3.90%
E344	OTHER	Generators	3.92%
E345	OTHER	Accessory Electric Equipment	2.90%
E346	OTHER	Miscellaneous Power Plant Equipment	4.70%
E348	OTHER	Energy Storage Equipment – Production	0.00%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.74%
*E352	Structures and Improvements-Prod.	1.74%
E353	Station Equipment	2.15%
*E353	Station Equipment-Prod.	2.15%
E354	Towers and Fixtures	2.04%
*E354	Towers and Fixtures-Prod.	2.04%
E355	Poles and Fixtures	2.56%
*E355	Poles and Fixtures-Prod.	2.56%
E356	Overhead Conductors & Devices	2.09%
*E356	Overhead Conductors & Devices-Prod.	2.09%
E357	Underground Conduit	1.42%
E358	Underground Conductors & Devices	2.11%
DISTRIBUTION		
E361	Structures and Improvements	2.26%
*E361	Structures and Improvements-Prod.	2.29%
E362	Station Equipment	2.61%
*E362	Station Equipment-Prod.	2.65%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	5.38%
E365	Overhead Conductors and Devices	3.54%
E366	Underground Conduit	1.99%
E367	Underground Conductor and Devices	2.41%
E368	Line Transformers	3.44%
E368	Line Capacitors	4.53%
E369	Overhead Services	5.00%
E369	Underground Services	2.58%
E370	Meters	6.89%
E370.2	AGIS Meters	5.02%
E370.3	Electric Vehicle Chargers	10.33%
E373	Street Lighting and Signal Systems	5.24%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

GENERAL - ELECTRIC

E302	Franchises & Consents	4.91%
E303	Intangible Plant – 5 Year	20.48%
E303	Intangible Plant – 10 Year	10.06%
E390	Structures and Improvements	1.89%
E391	Office Furniture and Equipment	4.90%
E391	Network Equipment	16.89%
E392	Transportation Equipment – Auto	9.35%
E392	Transportation Equipment – Light Truck	8.67%
E392	Transportation Equipment – Trailers	6.91%
E392	Transportation Equipment – Heavy Trucks	7.32%
E393	Stores Equipment	4.86%
E394	Tools, Shop and Garage Equipment	6.58%
E395	Laboratory Equipment	9.77%
E396	Power Operated Equipment	6.27%
E397	Communication Equipment – General	10.03%
E397	Communication Equipment – Two Way	9.94%
E397	Communication Equipment – AMR	6.37%
*E397	Communication Equipment – EMS	6.58%
E397	Communication Equipment – Smart Grid	5.35%
E398	Miscellaneous Equipment	6.60%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	2024 Approved Accrual	Docket No./Case No.
Minnesota Retail	$21,571,110	E002/M-20-855
North Dakota Retail	$2,250,002	PU-20-441
South Dakota Retail	$2,769,552	EL22-017
Wisconsin Retail	$9,300,587	E002/M-20-855 4220-UR-126

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2024 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	6.17%
E312	STEAM	Boiler Plant Equipment	5.31%
E314	STEAM	Turbogenerator Units	4.40%
E315	STEAM	Accessory Electric Equipment	6.92%
E316	STEAM	Miscellaneous Power Plant Equipment	4.27%
E302	HYDRO	Franchises & Consents	1.46%
E331	HYDRO	Structures and Improvements	3.57%
E332	HYDRO	Reservoirs, Dams and Waterways	4.20%
E333	HYDRO	Water Wheels, Turbines & Generators	4.85%
E334	HYDRO	Accessory Electric Equipment	5.58%
E335	HYDRO	Miscellaneous Power Plant Equipment	5.04%
E341	OTHER	Structures and Improvements	5.05%
E342	OTHER	Fuel Holders, Producers & Accessories	4.24%
E343	OTHER	Prime Movers	5.06%
E344	OTHER	Generators	5.57%
E345	OTHER	Accessory Electric Equipment	5.73%
E346	OTHER	Miscellaneous Power Plant Equipment	2.93%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.09%
*E352		Structures and Improvements-Prod.	2.09%
E353		Station Equipment	2.80%
*E353		Station Equipment-Prod.	2.80%
E354		Towers and Fixtures	1.80%
E355		Poles and Fixtures	3.28%
E356		Overhead Conductors & Devices	2.80%
E357		Underground Conduit	1.76%
E358		Underground Conductors & Devices	2.77%
E359		Roads and Trails	1.75%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit IX

DISTRIBUTION		
E361	Structures and Improvements	2.03%
*E361	Structures and Improvements – Prod.	2.03%
E362	Station Equipment	2.51%
*362	Station Equipment – Prod.	2.51%
E363	Energy Storage Equipment – Distribution	10.00%
E364	Poles, Towers and Fixtures	5.26%
E365	Overhead Conductors and Devices	3.51%
E366	Underground Conduit	1.62%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	2.28%
E368	Line Capacitors	2.66%
E369	Overhead Services	3.61%
E369	Underground Services	2.73%
E370	Meters	4.54%
E370.1	Meters – Old	0.00%
E370.2	AGIS Meters	5.00%
E370.6	Meters – AMR	4.84%
E371	Customer Installations	0.00%
E371.4	Installations on Customer's Premises-EV	10.00%
E371.5	Customer Prem-REMS	3.33%
E373	Street Lighting and Signal Systems	5.72%
GENERAL ELECTRIC		
E302	Franchises & Consents	5.00%
E303	Intangible Plant – 3 Year	33.33%
E303	Intangible Plant – 5 Year	25.98%
E303	Intangible Plant – 7 Year	14.29%
E303	Intangible Plant – 10 Year	10.00%
E303	Intangible Plant – 15 Year	6.76%
E390	Structures and Improvements	2.17%
E391	Office Furniture and Equipment	4.57%
E391	Network Equipment	18.83%
E392	Transportation Equipment – Auto	12.67%
E392	Transportation Equipment – Light Truck	12.38%
E392	Transportation Equipment – Trailers	5.62%
E392	Transportation Equipment – Heavy Truck	8.21%
E393	Stores Equipment	4.45%
E394	Tools, Shop and Garage Equipment	4.80%
E395	Laboratory Equipment	3.45%
E396	Power Operated Equipment	5.96%
E397	Communication Equipment – AES/AMR	6.11%
*E397	Communication Equipment – EMS	6.11%
E398	Miscellaneous Equipment	4.48%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit X

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant	X	

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit X**

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Classification Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
548.1	Operation of energy storage equipment	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

Northern States Power Companies
Interchange Agreement
Comparison of Costs - Present and Proposed Rate Schedules – Amendment to Interchange Agreement – Annual Update

Appendix A
Page 1

Specification of Average Monthly Coincidental Peak Demands
2024 Calendar Year

		Minnesota Company			Wisconsin Company		
Year/Month		**Peak Demand MW**	**Transmission Loss Multiplier**	**Distribution Level Demand MW**	**Peak Demand MW**	**Transmission Loss Multiplier**	**Distribution Level Demand MW**
January 2022	A	5,352	0.96	5,138	1,071	0.952	1,020
February	A	5,194	0.96	4,986	1,016	0.952	967
March	A	4,798	0.96	4,606	965	0.952	918
April	A	4,628	0.96	4,443	938	0.952	893
May	A	5,607	0.96	5,383	1,125	0.952	1,071
June	A	7,883	0.96	7,567	1,362	0.952	1,297
July	A	7,686	0.96	7,378	1,323	0.952	1,259
August	A	7,446	0.96	7,148	1,318	0.952	1,255
September	A	6,857	0.96	6,583	1,232	0.952	1,173
October	A	4,661	0.96	4,475	936	0.952	891
November	A	4,748	0.96	4,558	1,062	0.952	1,011
December 2022	A	5,325	0.96	5,112	1,128	0.952	1,074
Total 2022		70,185		67,377	13,476		12,829
January 2023	A	5,079	0.96	4,875	1,092	0.952	1,040
February	A	5,056	0.96	4,854	1,077	0.952	1,025
March	A	4,671	0.96	4,484	1,001	0.952	953
April	A	5,115	0.96	4,910	941	0.952	896
May	A	6,389	0.96	6,133	1,152	0.952	1,096
June	A	6,796	0.96	6,524	1,205	0.952	1,147
July	F	7,219	0.96	6,931	1,264	0.952	1,203
August	F	7,227	0.96	6,938	1,258	0.952	1,197
September	F	6,292	0.96	6,040	1,113	0.952	1,059
October	F	4,703	0.96	4,515	919	0.952	875
November	F	4,771	0.96	4,580	1,070	0.952	1,019
December 2023	F	5,297	0.96	5,085	1,125	0.952	1,071
Total 2023		68,615		65,870	13,216		12,582
January 2024	F	5,357	0.96	5,143	1,122	0.952	1,068
February	F	4,968	0.96	4,770	1,068	0.952	1,017
March	F	4,795	0.96	4,603	1,055	0.952	1,005
April	F	4,383	0.96	4,208	840	0.952	800
May	F	5,648	0.96	5,422	1,072	0.952	1,020
June	F	6,922	0.96	6,645	1,341	0.952	1,277
July	F	7,250	0.96	6,960	1,280	0.952	1,219
August	F	7,275	0.96	6,984	1,256	0.952	1,196
September	F	6,238	0.96	5,989	1,101	0.952	1,048
October	F	4,670	0.96	4,483	904	0.952	861
November	F	4,735	0.96	4,546	1,063	0.952	1,012
December 2024	F	5,263	0.96	5,053	1,142	0.952	1,087
Total 2024		67,505		64,805	13,244		12,608
3 Three Total		206,305	0.96	198,052	39,937	0.952	38,020
			2024 CP Ratio	**0.838948**		**2024 CP Ratio**	**0.161052**

A = Actual
F = Forecast

Northern States Power Companies **Appendix A**
Interchange Agreement **Page 2**
Comparison of Costs - Present and Proposed Rate Schedules
Allocation of 2024 Estimated Demand Costs, at Authorized, and Proposed Peaks
IMPACT OF CHANGE IN ANNUAL DEMAND ALLOCATORS – Amendment to Interchange Agreement – Annual Update

	2024 Estimated Demand Costs		
	NSP-M	**NSP-W**	**System**
Production	Demand Costs	Demand Costs	Demand Costs
Fixed Charges-Demand	918,345,861.83	$38,881,510	$957,227,372
Fixed O & M, Capacity Purchases, & Other	607,702,777	23,821,503	631,524,280
Total	$1,526,048,639	$62,703,014	$1,588,751,652
Transmission			
Fixed Charges	417,309,434.69	$166,003,399	$583,312,834
Fixed Portion of O & M	55,713,202	16,113,164	71,826,366
Net Transmission Expense & Wheeling Revenues	(53,872,576)	n/a	(53,872,576)
Total	$419,150,060	$182,116,563	$601,266,623
Total Estimated Demand Costs	$1,945,198,699	$244,819,577	$2,190,018,276

	Allocate 2024 System Demand Costs Using 2023 Authorized CP's		
	NSP-M	**NSP-W**	**System**
Coincident Peak Ratios (CP's)			
Authorized Transmission Loss Rate	0.038	4.40%	
Authorized Demand Loss Multipliers	0.962	0.956	
2023 Authorized CP Ratio	0.838765	0.161235	1.000000
Net Costs using 2023 Authorized CP's - Production	$1,332,589,280	$256,162,373	$1,588,751,652
Net Costs using 2023 Authorized CP's - Transmission	504,321,399	96,945,224	601,266,623
Total Allocated Demand Costs @ Authorized CP's	$1,836,910,679	$353,107,597	$2,190,018,276

	Allocate 2024 System Demand Costs Using 2024 Proposed CP's		
Coincident Peak Ratios (CP's)			
Proposed Transmission Loss Rate	4.00%	4.80%	
Proposed Demand Loss Multipliers	0.96	0.952	
2024 Proposed CP Ratio	**0.838948**	**0.161052**	**1.000000**
Net Costs using 2024 Proposed CP's - Production	$1,332,880,021	$255,871,631	$1,588,751,652
Net Costs using 2024 Proposed CP's - Transmission	504,431,431	96,835,192	601,266,623
Total Allocated Demand Costs @ Proposed CP's	$1,837,311,453	$352,706,823	$2,190,018,276

	Change In Cost of Service (with Proposed Loss Multipliers)		
	NSP-M	**NSP-W**	**System**
Change in Ratios	0.000183	(0.000183)	0.00000
Change in Production	$290,742	($290,742)	($0)
Change in Transmission	110,032	(110,032)	(0)
Total Change in Cost of Service	$400,773	($400,773)	($0)

Northern States Power Company
Interchange Agreement
Comparison of Costs - Present and Proposed Rate Schedules
Effect On 2024 Budget

Appendix A
Page 3

	NSP(M)	NSP(W)
Coincident Peaks Ratio	0.838948	0.161052

Present Depreciation Rates

		NSP-M	NSP-W	System
Production				
NSP-M to NSP-W	$523,402,185	$439,107,216	$84,294,969	$523,402,185
NSP-W to NSP-M	25,157,410	21,105,759	4,051,651	25,157,410
Total Production	$548,559,595	$460,212,975	$88,346,620	$548,559,595
Transmission				
NSP-M to NSP-W	$94,130,819	$78,970,862	$15,159,957	$94,130,819
NSP-W to NSP-M	48,679,788	40,839,811	7,839,977	48,679,788
Total Transmission	$142,810,607	$119,810,673	$22,999,934	$142,810,607
Distribution				
NSP-M to NSP-W	$116,378	$97,635	$18,743	$116,378
NSP-W to NSP-M	3,546	2,975	571	3,546
Total Distribution	$119,924	$100,610	$19,314	$119,924
General System Control				
NSP-M to NSP-W	$4,891,485	$4,103,702	$787,783	$4,891,485
NSP-W to NSP-M	891,386	747,827	143,559	891,386
Total General System Control	$5,782,871	$4,851,529	$931,342	$5,782,871
Total	$697,272,997	$584,975,787	$112,297,210	$697,272,997

Proposed Depreciation Rates

		NSP-M	NSP-W	System
Production				
NSP-M to NSP-W	$468,266,846	$392,851,534	$75,415,312	$468,266,846
NSP-W to NSP-M	27,134,502	22,764,436	4,370,066	27,134,502
Total Production	$495,401,348	$415,615,970	$79,785,378	$495,401,348
Transmission				
NSP-M to NSP-W	$99,649,362	$83,600,633	$16,048,729	$99,649,362
NSP-W to NSP-M	48,679,788	40,839,811	7,839,977	48,679,788
Total Transmission	$148,329,150	$124,440,444	$23,888,706	$148,329,150
Distribution				
NSP-M to NSP-W	$131,151	$110,029	$21,122	$131,151
NSP-W to NSP-M	3,546	2,975	571	3,546
Total Distribution	$134,697	$113,004	$21,693	$134,697
General System Control				
NSP-M to NSP-W	$5,117,007	$4,292,903	$824,104	$5,117,007
NSP-W to NSP-M	891,386	747,827	143,559	891,386
Total General System Control	$6,008,393	$5,040,730	$967,663	$6,008,393
Total	$649,873,588	$545,210,148	$104,663,440	$649,873,588

Change In Cost of Service

		NSP-M	NSP-W	System
Production				
NSP-M to NSP-W	($55,135,339)	($46,255,682)	($8,879,657)	($55,135,339)
NSP-W to NSP-M	1,977,092	1,658,677	318,415	1,977,092
Total Production	($53,158,247)	($44,597,005)	($8,561,242)	($53,158,247)
Transmission				
NSP-M to NSP-W	$5,518,543	$4,629,771	$888,772	$5,518,543
NSP-W to NSP-M	0	0	0	0
Total Transmission	$5,518,543	$4,629,771	$888,772	$5,518,543
Distribution				
NSP-M to NSP-W	$14,773	$12,394	$2,379	$14,773
NSP-W to NSP-M	0	0	0	0
Total Distribution	$14,773	$12,394	$2,379	$14,773
General System Control				
NSP-M to NSP-W	$225,522	$189,201	$36,321	$225,522
NSP-W to NSP-M	0	0	0	0
Total General System Control	$225,522	$189,201	$36,321	$225,522
Total	($47,399,409)	($39,765,639)	($7,633,770)	($47,399,409)

NSP Companies (NSPM/NSPW) 2023 Interchange Agreement Transmission Loss Study

Xcel Energy Services; Transmission Planning.

Craig Wrisley

Dylan Kohl

Jason Standing

October 24, 2023

Contents.

1.0: Scope of Study.

This study seeks to recommend revised demand and energy transmission loss percentages for Northern States Power Company Minnesota (“NSPM”) and Northern States Power Company Wisconsin (“NSPW”) (collectively “NSP” or “NSP Companies”) which are used to allocate costs in the Interchange Agreement. The losses in this study are based upon the data that has been collected from NSP’s state estimator for years 2019 through 2022.

2.0: Methodology.

This study uses NSP hourly state estimator data to calculate both the demand and energy losses on NSP’s transmission system. The state estimator has the ability to provide over 8000 states of data for calculating losses, which is significantly more than the amount possible during an offline study. The demand losses are defined as the losses that occur on NSP’s transmission system during the monthly peak hourly load, whereas energy losses are defined as the summation of all hourly losses in a given month. This analysis was performed for each month in the years 2019 through 2022 for which data has been collected. To calculate the required percentages, these losses will then be divided by NSP’s local balancing authority (LBA) load. In the case of demand losses, the load will be the peak hour load while the energy loss will be the summation of MW-Hr loads in the given month. Not all the loads in NSP’s LBA are NSP’s native load. Loads from Great River Energy (GRE) and Dairyland Power Cooperative (DPC) are within NSP’s LBA. Great River Energy is an electric cooperative based in Minnesota while Dairyland Power Cooperative is an electric cooperative based in Wisconsin. These loads also create losses on the transmission system and need to be added to NSP’s load to obtain the correct loss percentages. These loads will be added to the respective company divisors; GRE to NSPM and DPC to NSPW.

3.0: Description of Losses.

Losses are the portion of energy lost on the transmission system in the form of heat. There are several contributing factors to losses on the transmission system due to various factors listed below:

- NSP Local Balancing Authority electrical demand
- Generation Dispatch – the location and hours a generator operates will influence transmission losses
- Line outages – a planned or unexpected outage of a line can change the loading on the remaining system
- New facilities – new lines, substations, and generation can change the loading on the transmission and distribution system
- Power factor – power factor influences the current on the line, and therefore, the losses

- Temperature – the resistance of a conductor increases as the temperature increases. The conductor temperature is influenced by the combined effect of the ambient air temperature and wind velocity as well as the heat generated due to current flow in the conductor

4.0: Description of Local Balancing Authority.

A Balancing Authority Area, formerly known as a Control Area, is defined as all generators, loads, and transmission that are within a metered boundary. The Balancing Authority (BA) is the entity responsible for the regulation and stabilization for the grid frequency by balancing electric generation and electric demand. Currently, Midcontinent Independent System Operator (MISO) is the balancing authority for all MISO members, including NSP. However, NSP Companies are a party to the MISO's Balancing Authority Agreement as a Local Balancing Authority (LBA). This arrangement splits balancing authority responsibilities between MISO and NSP. NSP's LBA for this study will be defined as all generators, loads, and transmission that are within NSP's metered boundary.

5.0: Description of the State Estimator.

A State Estimator (SE) provides a complete complex voltage solution for the network model which is used for further analysis and computations. The SE solution is based on real-time measurements, scheduled load and generation, and dispatcher/operator entries. SE is performed several times per hour and provides a continuous snapshot of the network.

The Energy Management System (EMS) has real-time measurements received from the field through telemetry. The real-time measurements are imperfect but redundant. This redundancy permits the SE to determine an estimate for the voltage magnitude and angles for the observable portion of the network model which best matches the information given by the unfiltered measurements. For that portion of the network model that is unobservable (real-time measurements not available), load and generation is scheduled. These scheduled values along with any dispatcher/operator entries are used by the SE to determine a voltage magnitude and angle estimate for the unobservable portion of the network model.

The State Estimator accepts node voltage measurements, branch ampere magnitude measurements, as well as both active and reactive power measurements for node injection and branch flow (measurement pairs as well as unpaired measurements). In addition, the SE solution requires information on scheduled desired voltages, forecasted load, and generation. The SE processes status measurements such as logical device positions, transformers, and phase shifter tap positions. In addition to these status measurements, dispatcher/operator entry of equipment status (open/close or different tap position) and data base default status information is utilized to build a complete real-time network model.

The result of the State Estimator function is a real-time network description with a complete steady-state complex voltage solution. This solved real-time network is created for the use of the several applications in the EMS including the Transmission Loss Calculation function.

6.0: Loss Calculations.

For the calculation of the demand losses, the monthly peak in NSP's LBA was used. The calculations for the demand losses are as follows:

2019 Demand Loss Calculations

	NSPM			NSPW		
Month	2019 Peak Demand (MW)	2019 Peak Loss (MW)	Percentage Loss	2019 Peak Demand (MW)	2019 Peak Loss (MW)	Percentage Loss
January	5,523	177.55	3.21%	1,308	40.38	3.09%
February	5,138	209.28	4.07%	1,246	33.05	2.65%
March	5,133	254.61	4.96%	1,261	54.04	4.28%
April	4,662	148.49	3.18%	1,055	42.65	4.04%
May	4,860	129.50	2.66%	1,101	31.90	2.90%
June	5,969	174.08	2.92%	1,201	33.65	2.80%
July	7,167	215.13	3.00%	1,452	57.16	3.94%
August	6,237	154.44	2.48%	1,292	55.15	4.27%
September	6,362	212.04	3.33%	1,206	38.20	3.17%
October	4,493	123.75	2.75%	1,067	31.03	2.91%
November	5,026	240.96	4.79%	1,218	86.76	7.12%
December	5,196	226.72	4.36%	1,256	66.47	5.29%
Total	65,766	2,266.55	**3.48%**	14,663	570.44	**3.87%**

2020 Demand Loss Calculations

	NSPM			NSPW		
Month	2020 Peak Demand (MW)	2020 Peak Loss (MW)	Percentage Loss	2020 Peak Demand (MW)	2020 Peak Loss (MW)	Percentage Loss
January	5,093	273.84	5.38%	1,077	73.53	6.83%
February	4,996	256.75	5.14%	1,094	80.27	7.34%
March	4,593	253.88	5.53%	949	61.09	6.44%
April	4,244	242.05	5.70%	852	39.37	4.62%
May	5120	214.77	4.19%	986	53.05	5.38%
June	6,925	235.92	3.41%	1,191	36.78	3.09%
July	7,216	201.47	2.79%	1,356	49.37	3.64%
August	7,188	211.61	2.94%	1,217	43.1	3.54%
September	5,370	157.63	2.94%	980	47.83	4.88%
October	4,530	157.1	3.47%	953	56.94	5.98%
November	4,778	250.47	5.24%	947	75.13	7.94%
December	4,923	139.48	2.83%	1,034	42.93	4.15%
Total	64,975	2,594.97	**4.13%**	12,635	659.39	**5.32%**

2021 Demand Loss Calculations

Month	NSPM			NSPW		
	2021 Peak Demand (MW)	2021 Peak Loss (MW)	Percentage Loss	2021 Peak Demand (MW)	2021 Peak Loss (MW)	Percentage Loss
January	4,838	154.66	3.20%	1,024	50.91	4.97%
February	5,126	165.63	3.23%	1,096	35.88	3.27%
March	4,576	207.59	4.54%	981	38.92	3.97%
April	4,465	215.02	4.82%	837	41.07	4.91%
May	5,862	237.33	4.05%	1,057	62.80	5.94%
June	7,507	195.79	2.61%	1,330	39.48	2.97%
July	7,548	160.60	2.13%	1,213	31.54	2.60%
August	7,216	202.28	2.80%	1,232	44.47	3.61%
September	6,008	227.22	3.78%	996	41.00	4.12%
October	5,119	134.85	2.63%	992	30.04	3.03%
November	4,643	311.88	6.72%	950	65.46	6.89%
December	5,107	159.72	3.13%	1,061	44.91	4.23%
Total	68,014	2,372.57	**3.64%**	12,770	526.48	**4.21%**

2022 Demand Loss Calculations

Month	NSPM			NSPW		
	2022 Peak Demand (MW)	2022 Peak Loss (MW)	Percentage Loss	2022 Peak Demand (MW)	2022 Peak Loss (MW)	Percentage Loss
January	5,352	427.38	7.99%	1,071	85.26	7.96%
February	5,194	273.70	5.27%	1,016	41.38	4.07%
March	4,798	314.31	6.55%	965	80.72	8.37%
April	4,628	264.93	5.72%	938	71.29	7.60%
May	5,607	273.62	4.88%	1,125	74.30	6.61%
June	7,883	332.45	4.22%	1,362	67.27	4.94%
July	7,686	303.97	3.96%	1,323	57.76	4.37%
August	7,446	237.07	3.18%	1,322	55.67	4.21%
September	6,855	181.56	2.65%	1,232	48.28	3.92%
October	4,667	211.85	4.54%	936	77.22	8.25%
November	5,922	182.88	3.09%	1,062	41.63	3.92%
December	5,351	270.72	5.06%	1,128	52.89	4.69%
Total	71,388	3,274.44	**4.76%**	13,479	753.67	**5.74%**

Energy loss percentages were also calculated for the data collected for years 2019 through 2022.

2019 Energy Loss Calculations

	NSPM			NSPW		
Month	2019 Energy Demand (MWh)	2019 Energy Loss (MWh)	Percentage Loss	2019 Energy Demand (MWh)	2019 Energy Loss (MWh)	Percentage Loss
January	3,170,350	122,819	3.87%	781,544	35,800	4.58%
February	2,920,764	116,863	4.00%	708,121	28,944	4.09%
March	2,902,710	109,504	3.77%	721,223	36,109	5.01%
April	2,632,077	92,612	3.52%	632,666	27,147	4.29%
May	3,060,320	93,907	3.07%	696,204	30,255	4.35%
June	3,317,870	100,530	3.03%	718,438	36,073	5.02%
July	3,567,768	115,939	3.25%	777,766	45,346	5.83%
August	3,507,871	111,063	3.17%	766,023	45,601	5.95%
September	2,971,664	112,846	3.80%	668,411	45,560	6.82%
October	2,779,699	106,021	3.81%	659,011	34,365	5.21%
November	2,885,219	116,690	4.04%	699,151	46,679	6.68%
December	3,034,659	106,678	3.52%	734,397	40,649	5.54%
Total	36,750,970	1,305,471	**3.57%**	8,562,954	452,527	**5.28%**

2020 Energy Loss Calculations

	NSPM			NSPW		
Month	2020 Energy Demand (MWh)	2020 Energy Loss (MWh)	Percentage Loss	2020 Energy Demand (MWh)	2020 Energy Loss (MWh)	Percentage Loss
January	3,120,164	103,229	3.31%	645,556	30,303	4.69%
February	2,858,457	106,487	3.73%	606,758	33,261	5.48%
March	2,827,510	106,774	3.78%	587,891	30,062	5.11%
April	2,500,777	95,279	3.81%	507,599	23,529	4.64%
May	2,621,463	99,562	3.80%	515,852	30,167	5.85%
June	3,228,140	111,243	3.45%	597,004	26,827	4.49%
July	3,736,021	126,973	3.40%	702,052	33,790	4.81%
August	3,323,035	123,593	3.72%	663,880	34,737	5.23%
September	2,756,424	109,540	3.97%	544,145	35,483	6.52%
October	2,780,632	114,716	4.13%	574,394	32,262	5.62%
November	2,727,272	121,757	4.46%	563,942	28,277	5.01%
December	2,974,570	132,486	4.45%	637,836	33,205	5.21%
Total	35,454,464	1,351,638	**3.83%**	7,146,909	371,904	**5.22%**

2021 Energy Loss Calculations

Month	NSPM			NSPW		
	2021 Energy Demand (MWh)	2021 Energy Loss (MWh)	Percentage Loss	2021 Energy Demand (MWh)	2021 Energy Loss (MWh)	Percentage Loss
January	3,013,337	132,725	4.40%	641,536	28,927	4.51%
February	2,869,663	110,397	3.85%	619,441	25,565	4.13%
March	2,774,326	121,760	4.39%	588,772	27,662	4.70%
April	2,621,506	116,756	4.45%	523,225	24,245	4.63%
May	2,781,516	101,203	3.64%	558,582	25,964	4.65%
June	3,566,487	117,526	3.30%	669,851	27,718	4.14%
July	3,694,849	111,524	3.02%	671,047	24,843	3.70%
August	3,568,391	126,852	3.55%	661,212	30,393	4.60%
September	2,944,960	117,463	3.99%	566,578	26,014	4.59%
October	2,823,038	118,485	4.20%	562,837	30,866	5.48%
November	2,779,124	162,416	5.84%	576,284	37,727	6.55%
December	2,979,564	183,405	6.16%	644,401	42,222	6.55%
Total	36,416,760	1,520,513	**4.23%**	7,283,764	352,146	**4.85%**

2022 Energy Loss Calculations

Month	NSPM			NSPW		
	2022 Energy Demand (MWh)	2022 Energy Loss (MWh)	Percentage Loss	2022 Energy Demand (MWh)	2022 Energy Loss (MWh)	Percentage Loss
January	3,306,110	193,539	5.85%	676,675	43,320	6.40%
February	2,940,270	164,051	5.58%	597,585	39,810	6.66%
March	2,953,560	165,191	5.59%	615,635	38,156	6.20%
April	2,730,208	160,550	5.88%	563,786	36,537	6.48%
May	2,822,052	109,595	3.88%	567,052	35,568	6.27%
June	3,314,546	132,391	3.99%	631,086	38,808	6.15%
July	3,645,576	152,133	4.17%	690,962	38,599	5.59%
August	3,462,460	136,094	3.93%	688,194	37,564	5.46%
September	2,998,271	124,198	4.14%	617,500	40,215	6.51%
October	2,752,727	119,131	4.33%	589,286	36,778	6.24%
November	2,793,634	138,315	4.95%	604,522	37,222	6.16%
December	3,094,990	126,913	4.10%	670,081	38,411	5.73%
Total	36,814,404	1,722,102	**4.70%**	7,512,366	460,989	**6.15%**

With the numbers calculated in this study, a 48 month average was calculated to provide recommended loss factors for the Interchange Agreement. These recommended loss factors are shown in the table below.

2022 NSP Loss Study Ratios (proposed loss factors)		
Loss Ratios	NSPM	NSPW
Demand	4.00%	4.79%
Demand (Rounded)	4.0%	4.8%
Energy	4.08%	5.38%
Energy (Rounded)	4.1%	5.4%

7.0: Validation of Energy Management System (EMS) Losses.

Validation was performed on NSP's state estimator data, which is sourced from NSP's Energy Management System (EMS), to ensure accurate results for this loss study. Two forms of validation were performed with a criterion that results should be within 5 percent. The first validation was to compare NSP's state estimator data with an independent set of data. In this case, the MISO state estimator loss data was chosen. One detail to note is that the MISO state estimator only monitors facilities under MISO functional control. The facilities under MISO functional control are 100 kV and above. This means, in order to compare the two state estimator results, NSP's data needs to be restricted to assets that are 100 kV and above. The second validation will be to perform offline calculation in PSS/e for the sub-100 kV assets.

Validation of NSP EMS Losses vs. MISO State Estimator Losses

The NSP state estimator results were compared to the MISO state estimator results for validation purposes. Peak hour data from August 26, 2013 at 5 p.m. was used for this comparison and validation. MISO's state estimator calculated NSP Local Balancing Authority (LBA) losses at 265 MW. NSP's state estimator calculated a total of 261.97 MW for the 100 kV and above assets. The two state estimator calculations differ by 1.5 percent, which is an acceptable variance for validation.

Validation of NSP EMS Losses vs. PSS/e Offline Powerflow Calculations

To validate the state estimator losses for assets that are below 100 kV, an offline comparison was performed using the same August 26th peak hour data. A PSS/e powerflow model was setup to recreate the flows observed on the state estimator on the August 26, 2013 peak hour. The flow is recreated by a two bus system in which the observed flow is recreated by a negative load with a swing bus to calculate the losses. The swing bus would also regulate the voltage on the load bus to 1 per unit (pu). The impedance for the 69 kV lines was obtained from NSP's CAPE models, which contain the most accurate data for line impedances for NSP transmission lines.

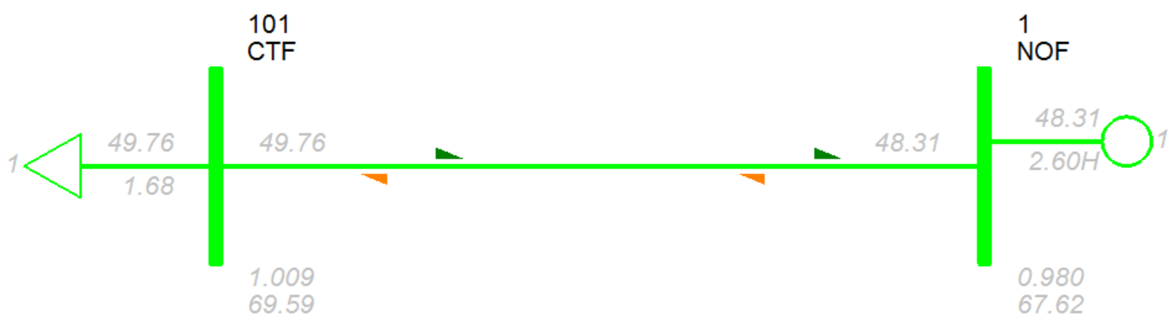
The first transmission line selected for verification is the Cannon Falls – Northfield 69 kV transmission line. The impedance parameters provided by NSP's CAPE model for this line are:

R = .05956 pu, X = .19297 pu, B = .00417 pu

The state estimator data for this line is as follows:

Company	Division	Sub Station	Name	Type	Volt	Src Rpt Date	Src Rpt Hr	Mw	Mvar	Loss
NSP	KEYSTN	CTF	CTF-NOF	LINE	69	8/26/2013	17:13	49.76	1.68	1.44

A PSS/e model was created in PSS/e version 33.6 to recreate the flows observed in the state estimator. The real power flow condition of 49.76 MW leaving the Cannon Falls Transmission substation was recreated by a negative load and a swing bus being placed at Northfield bus to solve for the loss on the Cannon Falls Transmission – Northfield 69 kV line. Upon solving this simple model, PSS/e calculated a loss value of 1.45 MW, which is slightly higher than the 1.44 MW calculated by the state estimator. However, this difference is less than 1 percent, which validates the state estimator results.

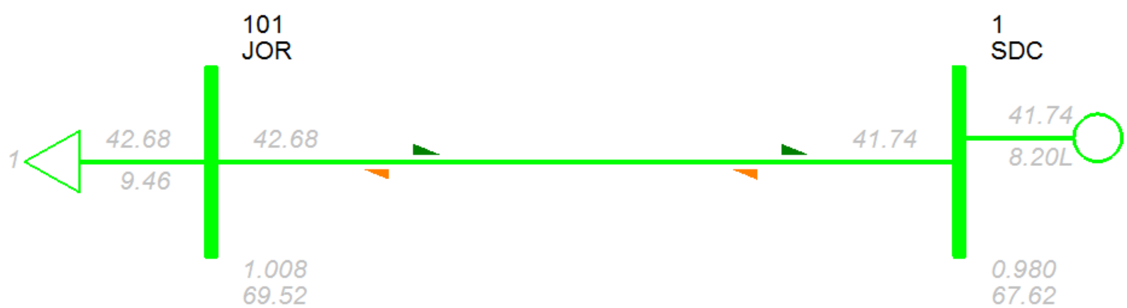


The Jordan to Sand Creek 69 kV transmission line was also selected as a line to validate the NSP companies state estimator results. The impedance parameters provided by NSP's CAPE model for this line are:

R = .04969 pu, X = .07283 pu, B = .00114 pu

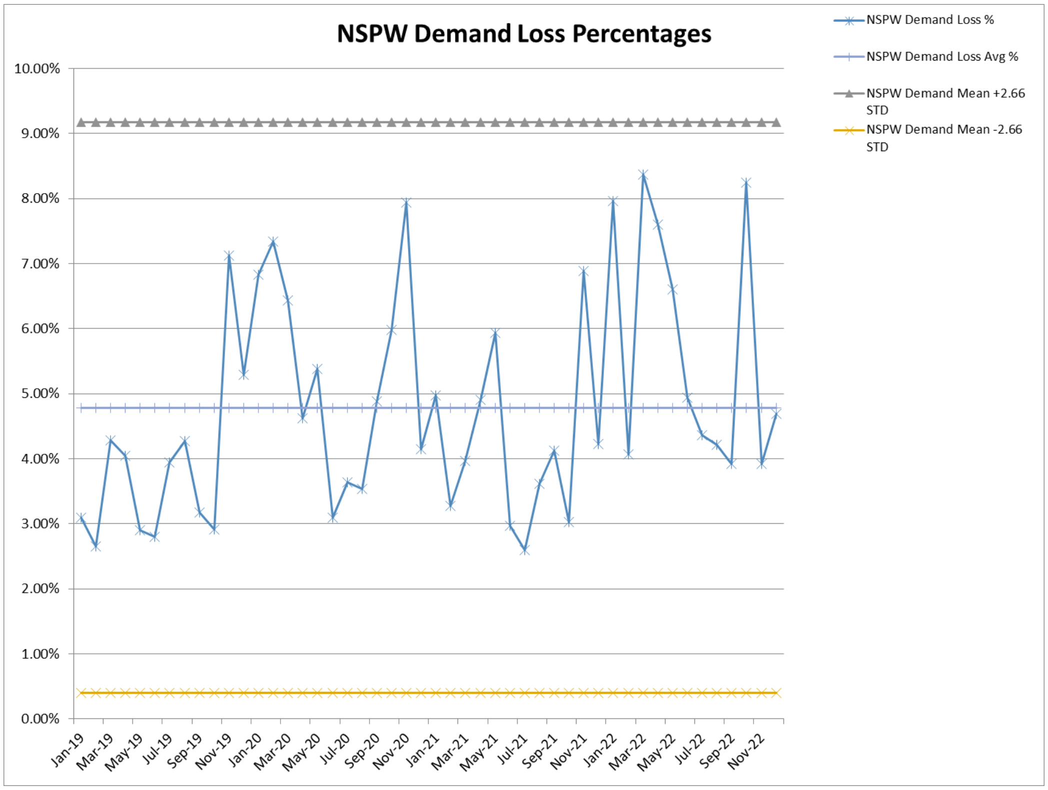
Company	Division	Sub Station	Name	Type	Volt	Src Rpt Date	Src Rpt Hr	Mw	Mvar	Loss
NSP	KEYSTN	JOR	JOR-SDC	LINE	69	8/26/13	17:13	42.68	9.46	0.93

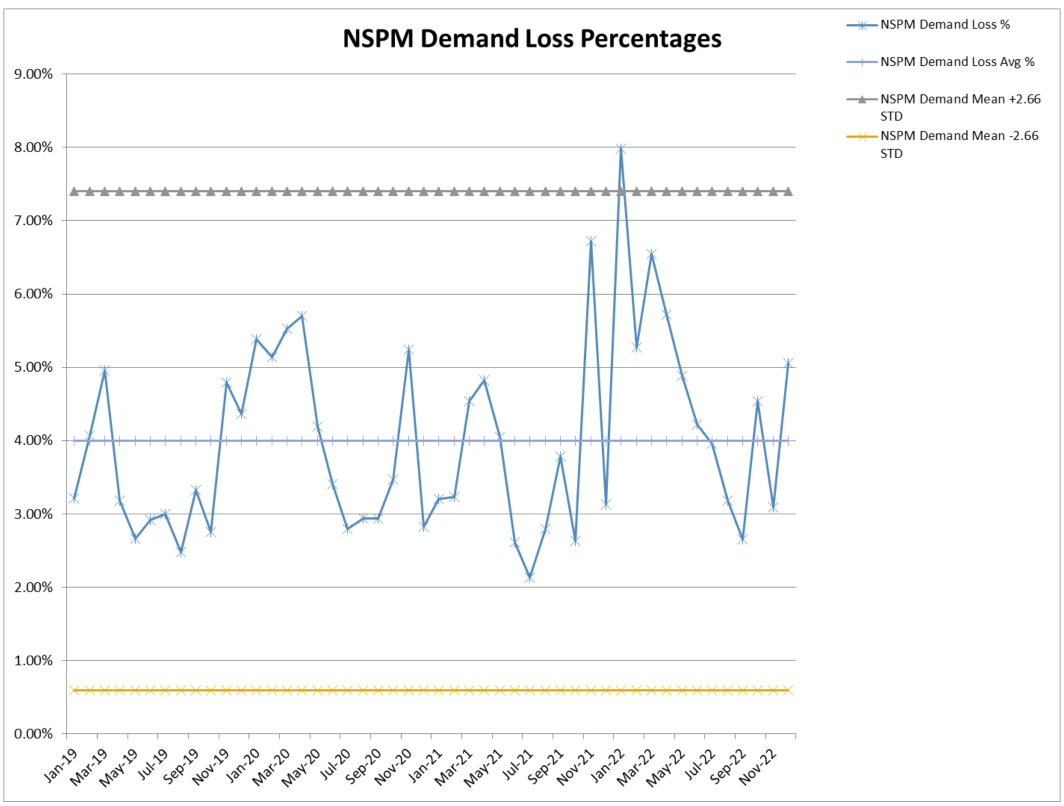
Again, a PSS/e model was created in PSS/e version 33.6 to recreate the actual flows observed in the state estimator. The real power flow was 42.68 MW leaving the Jordan substation and was recreated by a negative load and a swing bus was placed at Sand Creek bus to solve for the losses on the Jordan-Sand Creek 69 kV line. Upon solving this PSS/e model, PSS/e calculated a loss of 0.94 MW, which is slightly higher than the 0.93 MW calculated by the state estimator. This difference is approximately 1 percent, which validates the state estimator results.

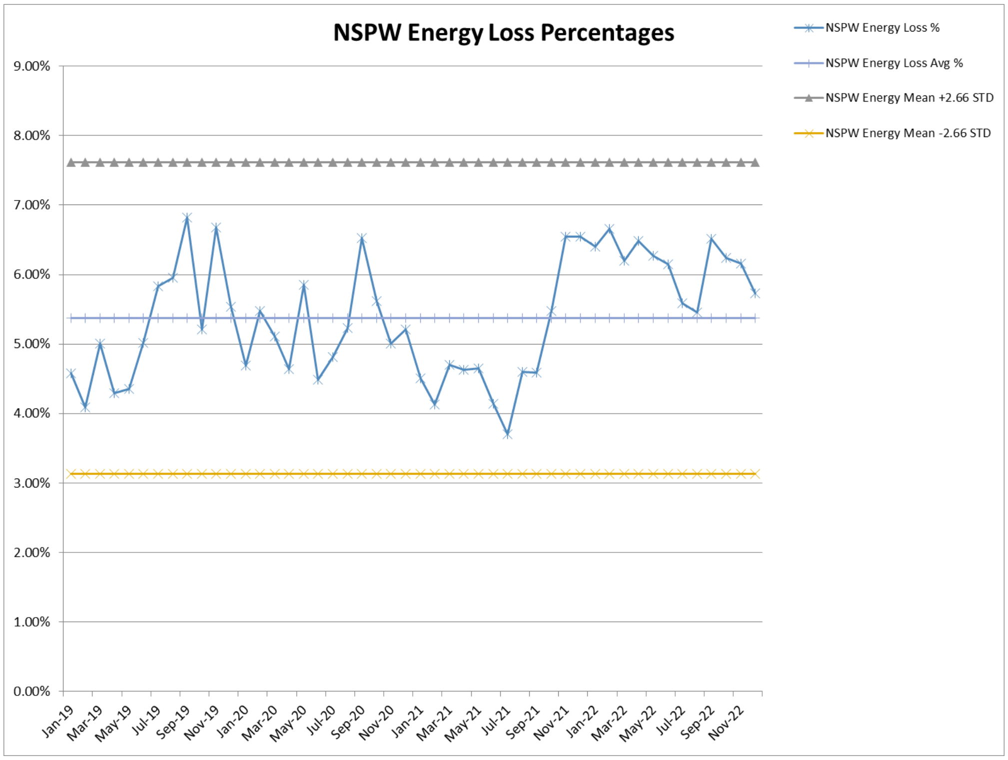


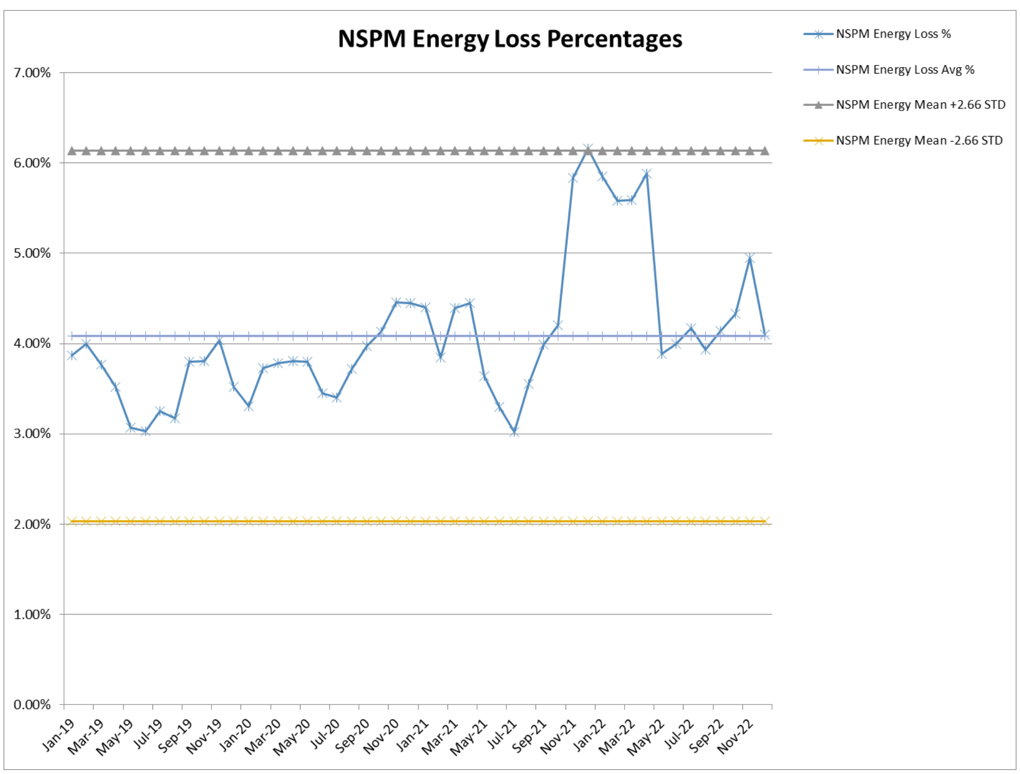
Validation of NSP EMS Losses statistical outlier analysis

A final validation was performed to identify any outlier percentages for the percentages that were calculated. The standard deviations were calculated for the four loss percentages in this report and multiplied by 2.66. This number was added and subtracted to the mean percentage and plotted in the graphs below. Any percentage outside of these bounds should only have less than a 1 percent probability and should be investigated further.


NSPW Demand Loss Percentages
NSPW Demand Loss %
NSPW Demand Loss Avg %
NSPW Demand Mean +2.66 STD
NSPW Demand Mean -2.66 STD
10.00%
9.00%
8.00%
7.00%
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
Jan-19 Mar-19 May-19 Jul-19 Sep-19 Nov-19 Jan-20 Mar-20 May-20 Jul-20 Sep-20 Nov-20 Jan-21 Mar-21 May-21 Jul-21 Sep-21 Nov-21 Jan-22 Mar-22 May-22 Jul-22 Sep-22 Nov-22


NSPM Demand Loss Percentages
NSPM Demand Loss %
NSPM Demand Loss Avg %
NSPM Demand Mean +2.66 STD
NSPM Demand Mean -2.66 STD
9.00%
8.00%
7.00%
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
Jan-19 Mar-19 May-19 Jul-19 Sep-19 Nov-19 Jan-20 Mar-20 May-20 Jul-20 Sep-20 Nov-20 Jan-21 Mar-21 May-21 Jul-21 Sep-21 Nov-21 Jan-22 Mar-22 May-22 Jul-22 Sep-22 Nov-22


NSPW Energy Loss Percentages
NSPW Energy Loss %
NSPW Energy Loss Avg %
NSPW Energy Mean +2.66 STD
NSPW Energy Mean -2.66 STD
9.00%
8.00%
7.00%
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20
Jul-20
Sep-20
Nov-20
Jan-21
Mar-21
May-21
Jul-21
Sep-21
Nov-21
Jan-22
Mar-22
May-22
Jul-22
Sep-22
Nov-22


NSPM Energy Loss Percentages
NSPM Energy Loss %
NSPM Energy Loss Avg %
NSPM Energy Mean +2.66 STD
NSPM Energy Mean -2.66 STD
7.00%
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
Jan-19
Mar-19
May-19
Jul-19
Sep-19
Nov-19
Jan-20
Mar-20
May-20
Jul-20
Sep-20
Nov-20
Jan-21
Mar-21
May-21
Jul-21
Sep-21
Nov-21
Jan-22
Mar-22
May-22
Jul-22
Sep-22
Nov-22

December 2021, NSPM energy loss percentage data was outside of 2.66 standard deviations from the mean. In addition to the Lakefield – Fieldon – Wilmarth 345kV line being brought back online, the new Huntley – Wilmarth 345kV line was completed and brought online on December 1st, 2021. With high wind, the Lakefield – Fieldon – Wilmarth and Huntley – Wilmarth 345kV lines caused larger flows from southwest Minnesota, resulting in larger losses throughout the system for the month of December.

NSPM demand loss percentage data was outside of the 2.66 standard deviations from the mean for the month of January 2022. During the January peak load hour, high wind generation pushed flows into the Wisconsin area, causing large losses on the Allen S King – Eau Claire 345kV line and the Hawks Nest Lake – Lyon Co 345kV line.

NSP System
Benson Biomass Termination
Annual Revenue Requirement

Appendix C-1
Page 1

Assumptions:	
Capital Structure	**2024**
Long Term Debt Rate	**4.4546%**
Long Term Debt Ratio	**47.3590%**
Common Equity Rate	**9.2500%**
Common Equity Ratio	**52.6410%**
Overall Rate of Return	**6.9789%**
Interchange Energy Allocation (2018 Budget) (Fixed for amortization term)	
NSPM	**83.7881%**
NSPW	**16.2119%**
	100.0000%
NSPM Tax Rate (Composite)	**28.0320%**

	Payments	Accruals	Total
NSP System (Account 182.2)	48,044,295		48,044,295
2018 Budget Energy Allocator	16.2119%		16.2119%
NSPW Allocation (Account 182.2)	**7,788,893**		**7,788,893**
NSP System (Account 182.3)	49,485,690	0	49,485,690
2018 Budget Energy Allocator	16.2119%	16.2119%	16.2119%
NSPW Allocation (Account 182.3)	**8,022,571**	**0**	**8,022,571**
NSP System (Total)	97,529,985	0	97,529,985
2018 Budget Energy Allocator	16.2119%	16.2119%	16.2119%
NSPW Allocation (Total)	**15,811,464**	**0**	**15,811,464**

NSPW (Account 182.2)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
Regulatory Asset	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	7,788,893	
Accumulated Amortization	4,254,997	4,318,290	4,381,584	4,444,878	4,508,171	4,571,465	4,634,759	4,698,052	4,761,346	4,824,640	4,887,933	4,951,227	
CWIP	0	0	0	0	0	0	0	0	0	0	0	0	
Accumulated Deferred Taxes	993,240	975,451	957,662	939,872	922,083	904,294	886,504	868,715	850,925	833,136	815,347	797,557	
13 Month Average Rate Base	2,540,656	2,495,152	2,449,647	2,404,143	2,358,639	2,313,135	2,267,630	2,222,126	2,176,622	2,131,117	2,085,613	2,040,109	
Tax Depreciation & Removal	0	0	0	0	0	0	0	0	0	0	0	0	
Debt Return	4,467	4,387	4,307	4,227	4,147	4,067	3,987	3,907	3,827	3,747	3,667	3,587	48,319
Equity Return	10,309	10,125	9,940	9,755	9,571	9,386	9,201	9,017	8,832	8,648	8,463	8,278	111,525
Current Income Tax Requirement	21,740	21,668	21,596	21,524	21,452	21,380	21,308	21,236	21,164	21,092	21,021	20,949	256,130
Amortization	63,294	63,294	63,294	63,294	63,294	63,294	63,294	63,294	63,294	63,294	63,294	63,294	759,524
Amortization (Accruals)	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Deferred Tax	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(17,789)	(213,473)
Total Revenue Requirements (182.2)	82,020	81,683	81,347	81,010	80,674	80,337	80,001	79,664	79,327	78,991	78,654	78,318	962,026

NSP System
Benson Biomass Termination
Annual Revenue Requirement

Appendix C-1
Page 2

NSPW (Account 182.3)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
Regulatory Asset	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	8,022,571	
Accumulated Amortization	4,292,756	4,359,559	4,426,361	4,493,164	4,559,967	4,626,770	4,693,572	4,760,375	4,827,178	4,893,981	4,960,783	5,027,586	
CWIP	0	0	0	0	0	0	0	0	0	0	0	0	
Accumulated Deferred Taxes	1,048,305	1,029,530	1,010,754	991,979	973,203	954,427	935,652	916,876	898,100	879,325	860,549	841,773	
13 Month Average Rate Base	2,681,509	2,633,482	2,585,455	2,537,428	2,489,401	2,441,374	2,393,347	2,345,320	2,297,292	2,249,265	2,201,238	2,153,211	
Tax Depreciation & Removal	0	0	0	0	0	0	0	0	0	0	0	0	
Debt Return	4,714	4,630	4,545	4,461	4,376	4,292	4,208	4,123	4,039	3,954	3,870	3,785	50,998
Equity Return	10,881	10,686	10,491	10,296	10,101	9,906	9,712	9,517	9,322	9,127	8,932	8,737	117,708
Current Income Tax Requirement	22,945	22,869	22,793	22,717	22,641	22,565	22,490	22,414	22,338	22,262	22,186	22,110	270,331
Amortization	66,803	66,803	66,803	66,803	66,803	66,803	66,803	66,803	66,803	66,803	66,803	66,803	801,633
Amortization (Accruals)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(10,820)
Annual Deferred Tax	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(18,776)	(225,308)
Total Revenue Requirements (182.3)	85,666	85,310	84,955	84,600	84,245	83,889	83,534	83,179	82,824	82,468	82,113	81,758	1,004,541

NSPW (Total)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
Regulatory Asset	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	15,811,464	
Accumulated Amortization	8,547,752	8,677,849	8,807,945	8,938,042	9,068,138	9,198,235	9,328,331	9,458,428	9,588,524	9,718,620	9,848,717	9,978,813	
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	
Accumulated Deferred Taxes	2,041,546	2,004,981	1,968,416	1,931,851	1,895,286	1,858,721	1,822,156	1,785,591	1,749,026	1,712,461	1,675,896	1,639,331	
13 Month Average Rate Base	5,222,165	5,128,634	5,035,103	4,941,571	4,848,040	4,754,508	4,660,977	4,567,445	4,473,914	4,380,383	4,286,851	4,193,320	
Tax Depreciation & Removal	-	-	-	-	-	-	-	-	-	-	-	-	
Debt Return	9,181	9,016	8,852	8,687	8,523	8,359	8,194	8,030	7,865	7,701	7,536	7,372	99,317
Equity Return	21,190	20,811	20,431	20,052	19,672	19,293	18,913	18,534	18,154	17,774	17,395	17,015	229,234
Current Income Tax Requirement	44,685	44,537	44,389	44,241	44,093	43,946	43,798	43,650	43,502	43,354	43,207	43,059	526,461
Amortization	130,096	130,096	130,096	130,096	130,096	130,096	130,096	130,096	130,096	130,096	130,096	130,096	1,561,157
Amortization (Accruals)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(10,820)
Annual Deferred Tax	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(36,565)	(438,780)
Total Revenue Requirements (Total)	167,685	166,994	166,302	165,610	164,918	164,227	163,535	162,843	162,151	161,459	160,768	160,076	1,966,568

Northern States Power Companies
Prairie Island EPU Amortization
Annual Revenue Requirement

Appendix C-2
Page 1

NSP System	**2024**
Regulatory Asset	78,884,915
Accumulated Amortization	36,215,347
CWIP	-
Accumulated Deferred Taxes	17,443,319
13 Month Average Rate Base	25,226,248
Debt Return	545,173
Equity Return	-
Current Income Tax Requirement	990,836
Amortization	4,302,814
Annual Deferred Tax	(1,758,990)
Tax Depreciation & Removal Expense	-
Property Taxes	-
Total Revenue Requirements	4,079,832

INPUTS:	
Capital Structure	
Long Term Debt Rate	**4.5345%**
Long Term Debt Ratio	**47.6597%**
Common Equity Rate	**0.0000%**
Common Equity Ratio	**52.3403%**
Overall Rate of Return	**2.1611%**
Tax Rate (Composite)	**28.0320%**
Demand (2014) Allocator - Fixed for the 18.3 year amortization term	
NSPM	**84.7923%**
NSPW	**15.2077%**
	100.0000%

NSP-Minnesota	
Regulatory Asset	66,888,334
Accumulated Amortization	30,707,826
CWIP	-
Accumulated Deferred Taxes	14,790,592
13 Month Average Rate Base	21,389,916
Debt Return	462,264
Equity Return	-
Current Income Tax Requirement	840,153
Amortization	3,648,455
Annual Deferred Tax	(1,491,488)
Tax Depreciation & Removal Expense	-
Property Taxes	-
Total Revenue Requirements	3,459,384

NSP-Wisconsin	
Regulatory Asset	11,996,581
Accumulated Amortization	5,507,521
CWIP	-
Accumulated Deferred Taxes	2,652,728
13 Month Average Rate Base	3,836,332
Debt Return	82,908
Equity Return	-
Current Income Tax Requirement	150,683
Amortization	654,359
Annual Deferred Tax	(267,502)
Tax Depreciation & Removal Expense	-
Property Taxes	-
Total Revenue Requirements	620,448

Northern States Power
Production Acquisition Adjustments

Appendix C-3
Page 1

Acquiring Company	Acquired Company/Asset	Acquisition Date	Acquisition Amount	FERC Authorization	Accounting Entries	Note
NSPM	Community Wind North Companies	12/31/2020	$35,040,269	Docket No. EC19-89-000 (July 17, 2019)	Docket No. AC21-135-000 (July 22, 2021)	A
NSPM	Jeffers Wind 20, LLC	12/31/2020	$27,245,674	Docket No. EC19-89-000 (July 17, 2019)	Docket No. AC21-135-000 (July 22, 2021)	B
NSPM	FPL Energy Mower County, LLC	3/23/2021	$14,931,200	Docket No. EC20-69-000 (August 20, 2020)	Docket No. AC21-162-000 (October 14, 2021)	C

Note A: *FERC Account 114 will be amortized ratably over a 25-year period from the acquisition date as approved by the Minnesota Public Utilities Commission in Docket No. E-002/PA-18-777. The amortization journal entry is a debit to FERC Account 406 Amortization of Electric Plant Acquisition Adjustments and a credit to FERC Account 115 Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments.*

The Community Wind North Companies include: Community Wind North, LLC; North Community Turbines LLC; North Wind Turbines LLC; Community Wind North 1 LLC; Community Wind North 2 LLC; Community Wind North 3 LLC; Community Wind North 5 LLC; Community Wind North 6 LLC; Community Wind North 7 LLC; Community Wind North 8 LLC; Community Wind North 9 LLC; Community Wind North 10 LLC; Community Wind North 11 LLC; Community Wind North 13 LLC; Community Wind North 15 LLC

Note B: *FERC Account 114 will be amortized ratably over a 25-year period from the acquisition date as approved by the Minnesota Public Utilities Commission in Docket No. E-002/PA-18-777. The amortization journal entry is a debit to FERC Account 406 Amortization of Electric Plant Acquisition Adjustments and a credit to FERC Account 115 Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments.*

Note C: *FERC Account 114 will be amortized ratably over a 25-year period from the acquisition date as approved by the Minnesota Public Utilities Commission in Docket No. E-002/PA-19-553. The amortization journal entry is a debit to FERC Account 406 Amortization of Electric Plant Acquisition Adjustments and a credit to FERC Account 115 Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments.*

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota

ISSUE DATE: July 17, 2023

DOCKET NO. E-002/GR-21-630

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Contents

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota

ISSUE DATE:

DOCKET NO. E-002/GR-21-630

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings

On October 25, 2021, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed a general rate case seeking three consecutive annual rate increases under the Multiyear Rate Plan statute phased as follows:

2022: $395.97 million increase (12.2%)
2023: $150.51 million increase (4.8%)
2024: $131.24 million increase (4.2%).

On December 23, 2021, the Commission issued three separate orders in this case: one finding the rate case filing substantially complete and suspending the proposed final rates; one referring the case to the Office of Administrative Hearings for contested case proceedings; and one setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Xcel Energy, represented by Shubha M. Harris, Matthew B. Harris, and Ian M. Dobson of Xcel; Eric F. Swanson, Elizabeth H. Schmiesing, and Joseph M. Windler of Winthrop and Weinstein; and Elizabeth M. Brama and Valerie T. Herring of Taft Stettinius & Hollister LLP.

- The Department of Commerce, Division of Energy Resources (the Department), represented by Katherine Hinderlie, Richard E.B. Dornfeld, and Greg Merz, Assistant Attorneys General.

- The Office of the Attorney General Residential Utilities Division (the OAG), represented by Kristin K. Berkland, Joseph C. Meyer, and Peter G. Scholtz, Assistant Attorneys General.

- Citizens Utility Board of Minnesota (CUB), represented by Brian Edstrom, Senior Regulatory Advocate, and Annie Levenson-Falk.

- The Commercial Group, represented by Alan R. Jenkins, Jenkins at Law, LLC.[1]

- The Suburban Rate Authority (SRA), represented by James M. Strommen and Joseph L. Sathe, of Kennedy & Graven.

- Xcel Large Industrials (XLI), represented by Andrew P. Moratzka and Riley A. Conlin, Stoel Rives, LLP.

- Energy CENTS Coalition (ECC), represented by Catherine Fair and Pam Marshall.

- Environmental Law & Policy Center, appeared on behalf of the Just Solar Coalition (Just Solar), represented by Scott Strand, Erica McConnell, and Bradley Klein.

- Minnesota Center for Environmental Advocacy, appeared on behalf of the Clean Energy Organizations (Fresh Energy and Minnesota Center for Environmental Advocacy), represented by Stephanie Fitzgerald and Amelia J. Vohs.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Christa L. Moseng to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings and initial and reply briefs after the close of evidentiary hearings.

The ALJ held evidentiary hearings on December 13 and 14, 2022. The ALJ also held public hearings in the case, as set forth below:

- October 4, 2022 in Golden Valley and Woodbury
- October 5, 2022 in Red Wing
- October 6, 2022 in St. Cloud
- October 20, 2022 in St. Paul
- October 21, 2022 in Minneapolis
- November 3, 2022 in Mankato

Virtual public hearings were held on October 31, November 2, and December 9, 2022. Written public comments were received until January 6, 2023.

[1] The Commercial Group is an ad hoc association of Xcel's large commercial customers; for purposes of this proceeding, the Group includes Penney OpCo LLC d/b/a JCPenney and Walmart Inc.

More than 500 members of the public attended the public hearings or filed written comments. Many comments opposed the proposed rate increase, citing adverse financial impacts and hardships that the increase would impose.

IV. Proceedings Before the Commission

On March 31, 2023, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law, and Recommendations (the ALJ's Report).

By April 17, 2023, the following parties had filed exceptions to the report of the Administrative Law Judge under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, XLI, SRA, the Commercial Group, Just Solar, Clean Energy Organizations, and CUB.

On May 23 and 24, and on June 1, 2023, the Commission heard oral argument from and asked questions of the parties.

On June 1, 2023, the record closed under Minn. Stat. § 14.61, subd. 2.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers . . .", citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. . . .

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate

[2] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[3] *In the Matter of the Request of Interstate Power Company for Authority to Change its Rates for Gas Service in Minnesota*, 574 N.W.2d 408, 410 (Minn. 1998).

recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, from the accuracy of the financial information provided by the utility to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking, the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court in a civil case, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

[4] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Supreme Court has explained:

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7] (Citation omitted.)

II. Summary of the Issues

Many initially contested issues were resolved among several of the parties in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them.

Other issues remained contested, and some issues resolved among the settling parties were disputed by one or more non-settling parties. The following issues either were contested or otherwise require discussion.

Financial Issues

- ***Allen S. King Generating Station (King) and Sherburne County Generating Station Unit 3 (Sherco 3)***–Should Xcel be allowed to shorten the remaining depreciable lives of Sherco 3 and King to reflect their early retirements?

- ***Long-term Incentive Compensation***–Should the Company be allowed to recover from its Minnesota ratepayers Minnesota's jurisdictional share of long-term incentive compensation expense?

- ***Annual Incentive Plan***–At what level should the Commission cap the Company's recovery of annual incentive plan compensation expense?

- ***Executive Compensation***–Should Xcel be allowed to fully recover executive compensation expenditures for its 10-highest paid executives?

- ***Prepaid Pension Asset***–Should the Company be allowed to earn a return on prepaid pension amounts?

[7] *In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota*, 435 N.W.2d 550, 554 (Minn.App. 1989).

- ***Qualified Pension Expense***–Should Xcel be allowed to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates?

- ***Medical and Post-Employment Benefits***–Should the Company be allowed to earn a return on its accrued liabilities for retiree medical and post-employment benefits?

- ***Energy Supply Operations and Maintenance (O&M) Expense***–Should the Company be allowed to recover 2022–2024 Energy Supply O&M expenses?

- ***Business System O&M Budget***–Should the Company be permitted to recover the cost of its 2022-2024 business systems O&M expenses?

- ***Income Tax Tracker Costs***–Should the Commission allow Xcel to recover its income tax tracker amount, which results in a 2022-2024 revenue requirement reduction?

- ***Aurora Solar Project Costs***–Should the Company be allowed to recover the Aurora Solar Project's deferred costs for the difference between the contracted power purchase agreement price and South Dakota Public Utilities Commission proxy price?

- ***Wind2Battery System Dismantling Costs***–Should the Commission approve costs for dismantling of the Wind2Battery System?

- ***Construction Work in Progress***–Should the Commission approve Xcel's proposal to include Construction Work in Progress (CWIP) in rate base as an average of projected CWIP beginning and ending balances?

- ***Fault Location Isolation and Service Restoration (FLISR)***–Should the Commission approve Xcel's proposed Fault Location Isolation and Service Restoration (FLISR) 2022-2024 cost recovery, cost allocation, and deployment strategy? Should Xcel be required to track and report on reliability performance for circuits equipped with FLISR and base future FLISR cost recovery on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR?

- ***Asset Health and Reliability***–Should the Commission approve Xcel's 2022-2024 Minnesota jurisdictional distribution capital addition costs for asset health and reliability?

- ***Integrated Distribution Plan (IDP)***–In its next IDP, should Xcel be required to propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases?

- ***Proactive Cable Replacements***–Should Xcel be required to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate case filing? Should Xcel be required to track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing?

- ***Distribution Capital Addition***–Should the Commission approve Xcel's distribution capital addition costs for the grid reinforcement program for the 2022–2024 test years?

- ***Distributed Intelligence***–Should the Commission approve Xcel's proposal for the Distributed Intelligence program without prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement?

- ***Production Tax Credits***–Should the Commission approve the Department's recommended baseline Production Tax Credits update?

- ***Load Flexibility Program***–Should the Commission approve Xcel's proposal to recover costs for the load flexibility program that were not deferred?

- ***IDP Filings***–Should Xcel be required to file an assessment and explanation in its next IDP of whether Integrated Volt-Var Optimization (IVVO) is in the public interest?

- ***Insurance Premium Costs***–Should Xcel be required to base 2022 insurance premium costs on historical averages as proposed by the Department?

- ***Membership Dues***–Should the Commission approve Xcel's request to recover Edison Electric Institute dues, American Gas Association dues, and Chambers of Commerce dues? Should Xcel be required to continue providing information mandated by Minn. Stat. § 216B.16, subd. 17, for all dues costs it seeks to recover regardless of the type of membership (individual, corporate, or chamber)?

- ***Carbon-Free Future MN Coalition Costs***–Should Xcel be allowed to recover Carbon-Free Future Minnesota Coalition costs?

- ***Advertising Expenses***–Should the Commission approve recovery of Xcel's advertising expenses?

Cost of Capital Issues

- ***Return on Equity***–What is a fair and reasonable return on equity for the Company, on this record, at this time?

Class Cost of Service Study (CCOSS) Issues

- ***CCOSS***–What action should the Commission take, if any, with respect to the class cost-of-service studies proposed in this case? What requirements, if any, should be established for future rate cases?

- ***General Allocator***–Should Xcel be required to calculate is General Allocator (for allocating costs among operations) based in part on the number of employees assigned to each operation, or on the full-time equivalent hours assigned to each operation? Should Xcel also be required to use its updated 2022 allocators in 2023 and 2024?

- ***Interchange Agreement Allocators***–Should Xcel be required to calculate its 2022 Interexchange Agreement Allocator (for distinguishing the cost of facilities used in its Minnesota operations from costs used in its Wisconsin operations) based on forecasted data, or based on updated data approved by the Federal Energy Regulatory Commission (FERC)? If the latter, should Xcel also have to make an equal adjustment to its forecasted Interexchange Agreement Allocators for 2023 and 2024?

Rate Design Issues

- ***Class Revenue Apportionment***–What percentage of the revenue requirement should be allocated to each customer class?

- ***Monthly Customer Charges–***At what amounts should monthly customer charges be set?

- ***Commercial & Industrial Demand Class***–Should Xcel be required to, in its next rate case, further segment the Commercial & Industrial Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I Time of Use (TOU) rate?

- ***Real Time Pricing Service Tariff***–Should the Commission allow Xcel to discontinue its Real Time Pricing Service Tariff?

- ***Business Incentive and Sustainability (BIS) Rider***–Should the Commission approve the Company's proposed discretionary discount for the BIS rider?

- ***Low-Income, Low-Usage Discount Program***–Should Xcel be required to implement the Low-Income, Low-Usage Discount Program as proposed by Energy Cents Coalition?

- ***Electric Vehicle (EV) Charging Rates and Upgrade Costs***–Should Xcel be allowed to waive the cost sharing requirement for EV-rate customers and exclude EV-rate customers from the general cost-sharing tariff? Should Xcel be required to include its proposal to waive cost sharing requirements for EV-rate customers to Xcel's Transportation Electrification Plan?

- ***Commercial & Industrial Demand Class–***Should Xcel be required to, in its next rate case, further segment the Commercial & Industrial Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I Time of Use (TOU) rate?

- ***Residential Space Heating Tariff–***Should the Commission approve Xcel's proposed changes to its Residential Space Heating Tariff?

- ***Residential Time-of-Use Rates–***Should the Commission require the Company to develop a residential time-of-use rate?

- ***Street Lighting Rate Design–***Should the Commission approve the Joint Stipulation between the Company and SRA?

- ***Advanced Rate Design–***Should the Commission open an Advanced Rate Design docket for Xcel?

- ***Sales True-Up–***Should the Commission approve Xcel's sales true-up for the term of the Multiyear Rate Plan?

- ***Rider Restrictions–***Should the Commission approve CUB's proposed restrictions on riders?

Energy Justice Tenets and Remaining Issues

- ***Energy Justice Tenets–***Should the Commission adopt Just Solar Coalition's recommendation to apply the principles of Energy Justice to this rate case?

- ***Term of the Multiyear Rate Plan–***Should the Company be required to file a five-year multiyear rate plan?

- ***Corporate Government-Dividend Policy–***Should the Commission initiate an investigation or the creation of a stakeholder group to examine the Company's corporate governance and dividend policy?

- ***Distributed Energy Resources – Circuit Breakers, Reclosers, and Regulator Replacement Prioritization***–Should the Commission direct the Company to modify its ELR programs to include the prioritization of replacements that would increase hosting capacity?

- ***Distributed Energy Resources – EV Charging Studies***–Should the Commission direct the Company to conduct additional studies to assess the potential costs and benefits that may result from encouraging EV charging during high solar generation periods?

- ***Grid Modernization***–Should the Company be required to comply with future grid modernization filing requirements?

- ***Energy Assistance***–Should the Company be required to take steps to address energy assistance budgets and qualifying customers to address barriers to assistance?

- ***Locational Reliability and Service Quality***–Should the Company be required to conduct analyses related to locational differences in reliability, disconnections, and service quality, specifically related to low-income and energy justice communities?

- ***Company Audit of Third-Party Sales Forecast Data***–Should the Company's request to eliminate its requirement to independently audit data obtained from third parties such as IHS Markit be approved?

- ***Regulatory Sandbox***–Should Xcel be required to work with interested parties and other utilities to discuss methods for improving the effectiveness and efficiency of pilot programs?

- ***Quantifying Incremental Hosting Capacity Beneficial Electrification***–Should Xcel be required to determine the incremental hosting capacity and beneficial electrification accommodation resulting from planned Asset Health and Reliability (AH&R) capital Expenditures?

- ***Unintentional Islanding***–Should the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) investigate unintentional islanding and research less costly alternatives to VSR to address the risk of unintentional islanding?

III. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held two days of formal evidentiary hearings and six public hearings. She reviewed the testimony of expert witnesses offered by 10 parties, and related hearing exhibits. She reviewed written comments submitted by over 500 members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. Based on this record, the ALJ made some 1,263 findings of fact and conclusions of law and made recommendations on stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations to the extent they are consistent with the decisions made herein.

FINANCIAL ISSUES

IV. Sherco 3 and King Plant Depreciation

A. Introduction

In Xcel's 2020–2034 resource-planning docket, the Commission approved Xcel's proposal to retire two coal-fired electric generating plants—Allen S. King Generating Station (King) and Sherburne County Generating Station Unit 3 (Sherco 3)—earlier than previously anticipated by nine and ten years, respectively.[8] Consistent with the Resource Plan Order, Xcel now plans to

[8] *In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Resource Plan Order), at 7, 31, Ordering Para. 2.A.4. (April 15, 2022).

retire King in 2028 and Sherco 3 in 2030 and has requested that the remaining depreciable lives of Sherco 3 and King be shortened to reflect their early retirements.

Utilities recover capital costs for assets that are used and useful in providing service by depreciating those costs over a number of years.[9] Commission rules generally require that an asset's costs be amortized over its probable service life, defined as the period of time "from the date of its installation to the forecasted date when it will probably be retired from service."[10] The depreciation rules reflect a regulatory preference to avoid intergenerational inequity (i.e., unfair distribution of costs among current and future customers), and to recover costs from ratepayers who receive the benefit of an asset while it is used and useful.

If a utility terminates operations of a facility before the end of the probable service life that was assumed when setting its depreciation schedule, there will be unrecovered net book value outstanding after the facility is retired. Ordinarily, remaining net book value is no longer recoverable once the facility stops being used and useful in the provision of utility service. However, under Minn. Stat. § 216B.16, subd. 6, the Commission may—but is not required to—allow a utility to recover a facility's positive net book value after retirement if the Commission ordered the facility to terminate operations before the end of its physical life "in order to comply with a specific state or federal energy statute or policy."

B. Positions of the Parties

1. Xcel, the Department, and the OAG

Xcel and the Department initially took different positions on the appropriate rate treatment for Sherco 3 and King in light of their early retirement.[11] However, by the time the Commission met to consider the matter, both Xcel and the Department had agreed that it would be reasonable to reserve this issue for further record development and consideration of alternative rate-treatment proposals in a new docket, particularly to explore whether the Inflation Reduction Act[12] could offer rate-mitigation opportunities.

The OAG did not oppose deferring the decision, but it maintained the position that there is no reasonable basis on which to authorize Xcel to earn a return on these investments once they are no longer used and useful, and its preferred recommendation was that the Commission make that determination in the current proceeding.

[9] *See* Minn. Stat. § 216B.16, subd. 6.

[10] Minn. R. 7825.0500, subps. 2, 10.

[11] Xcel initially proposed two alternative methods for reflecting the early retirement of the coal units: (1) allow the Company to implement the shortened accounting lives beginning in 2024, which would result in a $35.1 million increase in base rates for 2024; or (2) authorize the Company to defer the incremental depreciation expense until its next rate case and introduce a recovery proposal that could include establishing a regulatory asset. The Department initially recommended implementing the shortened accounting lives beginning in 2023 to reduce the magnitude of the rate impact in 2024.

[12] Inflation Reduction Act of 2022, Pub. L. No. 117–169, 136 Stat. 1818 (Aug. 16, 2022).

Xcel, the Department, and the OAG agreed that any financial adjustments resulting from decisions made in the new docket related to Sherco 3 and King rate treatment should be implemented in the Company's next rate case or other appropriate proceeding.

2. XLI

XLI opposed deferring this issue to a separate proceeding and instead continued to recommend that the Commission maintain the current depreciation schedules for King and Sherco 3 and require Xcel to remove each plant from rate base when it is no longer used and useful. However, XLI also recommended allowing the Xcel to recover any remaining balances for depreciation, operations and maintenance (O&M), property tax, and property insurance until those expenses are fully recovered, even after the plants are retired.

Because similar issues are likely to reoccur as utilities work to transition away from carbon-emitting generation resources, XLI recommended that the Commission open an investigation to establish a uniform cost-recovery policy for generation assets that are retired early by any utility in the state.

C. Recommendation of the Administrative Law Judge

Before Xcel and the Department agreed to explore this issue further in a new docket, the ALJ recommended that the Commission adopt a modified version of XLI's proposal that, in the ALJ's view, would maintain the status quo while preserving the Commission's ability to adopt a different approach in a future proceeding with a more fully developed record on the various options for post-retirement recovery. The ALJ found that this approach would be reasonable because the timing of the Resource Plan Order relative to this proceeding limited the parties' ability to develop a full record on the range of alternatives.

D. Commission Action

Although parties differed on the merits of rate treatment of costs related to early retirement of these assets, there was broad agreement that issues of depreciation accounting for early-retiring generation facilities will have significant ratepayer impacts and involve important policy considerations that have not been fully developed in this record. Accordingly, rather than adopt the ALJ's findings and recommendations on this issue at this time, the Commission will instead open a new docket to investigate depreciation accounting or other ratemaking issues related to the early retirement of generating facilities.

As the Department noted, the Inflation Reduction Act could provide opportunities to mitigate costs for ratepayers without leaving the Company uncompensated. Because this issue was introduced relatively late in the proceeding, a new docket will provide opportunities to develop a full record, including an exploration of these potential mitigations and any other potentially reasonable solutions.

Rather than limiting the discussion to Sherco 3 and King specifically, the new docket will address depreciation accounting and other ratemaking issues for retiring generating facilities for all Minnesota utilities. As multiple parties noted, similar issues are likely to reoccur as utilities continue to decarbonize their generation fleets in light of climate goals and changing economics.

Investigating these questions in a single docket with an eye toward broader policy considerations should encourage more robust stakeholder participation and record development and allow for more efficient and effective use of resources as compared to potentially having to revisit the same questions multiple times in individual facility-specific dockets.

For any depreciation adjustments that may be required for Sherco 3 or King as a result of the new docket, the Commission finds reasonable Xcel's proposal, agreed to by the Department and the OAG, to implement these changes in the Company's next rate case or other appropriate proceeding. This will help to avoid the possibility that Xcel may be left with a significant expense between rate cases that could prompt the Company to initiate a new general rate case before it otherwise would have, which may not be an effective use of regulatory, utility, and stakeholder resources.

V. Long-Term Incentive Compensation

A. Introduction

Parties disagreed about whether Xcel should recover the costs of two components of its long-term incentive (LTI) employee compensation—environmental LTI and time-based LTI. Environmental LTI is available only to executives. Xcel provided testimony that environmental LTI compensation is tied to the Company's goals to reduce the carbon-dioxide emissions associated with its electric service by 80% below 2005 levels by 2030 and to have 100% carbon-free electricity by 2050. If Xcel does not meet its environmental goals, then environmental LTI is not paid out, which means the employees do not receive their full market-based compensation amount. According to Xcel, activities that affect carbon emission levels and therefore may affect environmental LTI include implementing renewable energy resources, promoting energy efficiency programs, and improving plant operations to reduce carbon output.

Time-based LTI compensation is designed to incentivize both executive and non-executive employees to remain at the Company long term. It becomes available to eligible employees after a three-year vesting period. Time-based LTI is one of three LTI programs available to Xcel's executive-level employees and is the sole form of LTI offered to non-executive employees. For non-executive employees, time-based LTI payout is increased or decreased from the target amount based on a performance goal, which is the total shareholder return relative to a peer group for each individual vesting year. Time-based LTI paid to executives does not include this performance element.

The following table summarizes Xcel's LTI-expense requests:

Table 1
Xcel Requested LTI Expense ($Million)

	2022	**2023**	**2024**	**Total**
Environmental LTI	$2.210	$2.218	$2.329	$6.757
Time-Based LTI	$5.668	$5.960	$6.202	$17.830
Total LTI Expense	**$7.877**	**$8.178**	**$8.531**	**$24.586**

B. Positions of the Parties

1. Xcel

Xcel argued that customers benefit from tying a portion of an employee's total compensation to these incentive structures because it promotes superior employee performance by aligning compensation with results. Xcel contended that its environmental LTI compensation incentivizes environmental achievements aligned with environmental and climate goals. Xcel argued that its time-based LTI compensation helps the Company to provide efficient and reliable service by promoting the retention of experienced employees who have the knowledge and skills necessary to guide, manage, and operate the utility.

Additionally, Xcel asserted that its incentive-based compensation structure reduces fixed labor costs by reducing the level of base pay on which some benefit-related expenses are based.

2. The Department and XLI

The Department opposed Xcel's request to recover any LTI expense, arguing that these programs are designed chiefly to serve the interests of shareholders, not customers, so it would be unreasonable for customers to bear their costs.

The Department asserted that Xcel provided no detailed analysis of what environmental benchmarks would be achieved or the impact of any benchmarks on the environment beyond its general carbon-reduction goals as a result of environmental LTI spending. Additionally, Xcel earns returns on capital additions, including renewable-energy facilities, and the record does not show how environmental LTI compensation separately incentivizes Xcel's executives to achieve renewable-energy and environmental goals.

Similarly, the Department argued that Xcel has not shown that its time-based LTI compensation incentivizes employee performance related to the provision of safe and reliable service or otherwise benefits customers.

XLI joined the Department's arguments opposing Xcel's request to recover LTI expenses.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel has not met its burden to show that including its environmental LTI compensation in its rate base would be just and reasonable. Noting that the environmental goals underlying Xcel's environmental LTI program are not more ambitious than Minnesota's carbon-free standard,[13] the ALJ found that it would not be reasonable for ratepayers to pay for executive incentive compensation designed to incentivize utility actions that are currently required by law and for which the Company receives rate recovery.

[13] The "carbon-free standard" refers to 2023 Minn. Laws ch. 7, which amended Minn. Stat. § 216B.1691 to add the requirement that, by 2040, each electric utility generate or procure electricity from "carbon-free" technologies—those that generate electricity without emitting carbon dioxide—in an amount equivalent to 100% of the utility's total electric sales to retail customers in Minnesota.

Additionally, the ALJ agreed with the Department that Xcel's time-based LTI program is fundamentally tied to achieving shareholder goals, and that it is therefore unreasonable to require ratepayers to pay for those incentives.

Accordingly, the ALJ recommended that the Commission deny Xcel's request to recover costs for environmental and time-based LTI compensation and make the following corresponding reductions to Xcel's revenue requirements: $7,877,000 in 2022, $8,178,000 in 2023, and $8,531,000 in 2024.

D. Commission Action

The Commission concurs with the ALJ that Xcel did not meet its burden to establish that it would be just and reasonable for customers to pay for Xcel's time-based or environmental LTI compensation.

Xcel did not justify its environmental LTI costs with an adequate showing that the program offers unique benefits that justify separate rate recovery. The Commission is not persuaded that it would be reasonable to require customers to pay the requested $6.757 million in environmental long-term incentive compensation.

Nor did Xcel provide persuasive evidence that its time-based LTI will lead to additional customer benefits to justify imposing the additional $17.830 million cost on customers. To the contrary, the shareholder-return-based performance element of the time-based LTI program for non-executives may incentivize employees to prioritize shareholder interests over customer interests in order to increase their potential time-based LTI payout amount.

Therefore, the Commission will deny Xcel's requests to recover environmental and time-based LTI compensation expenses and will require the Company to make the corresponding revenue-requirement adjustments recommended by the ALJ.

VI. Annual Incentive Program

A. Introduction

Annual incentive program (AIP) is a short-term compensation program offered only to non-union employees. AIP is paid out only if the Company's earnings-per-share rate meets a target level. If the target is reached, then AIP is awarded to eligible employees based on a combination of the employee's achievement of individual performance goals and the Company's achievement of key performance indicators that Xcel develops annually. Xcel asserted that these performance indicators are aligned with customer-oriented goals related to the provision of safe and reliable electric service at reasonable cost.

According to Xcel, an employee's total compensation would be below market levels without AIP and the LTI programs discussed above.

Xcel currently recovers a portion of its AIP expense through rates. Recovery of each employee's AIP is capped at 15% of that employee's base salary. Xcel requested to recover Minnesota jurisdictional AIP expense totaling $24.005 million for 2022, $24.750 million for 2023, and

$25.524 million for 2024. Its request includes three changes from current AIP cost recovery: (1) increasing the cap on AIP compensation from 15% of base pay to 20%; (2) applying the cap on an aggregate basis rather than an individual-employee basis; and (3) removing the requirement that Xcel refund to ratepayers any portion of the total AIP balance collected through rates that is not paid out to employees for a given year.

Xcel also requested to eliminate its annual AIP compliance filing requirement and associated reports. Alternatively, Xcel proposed to change the reporting requirements to (1) compare the amounts of AIP paid to the amount authorized in rates in the aggregate rather than individual level; (2) eliminate the requirement to calculate whether AIP is under 105% of median overall compensation; and (3) eliminate calculations and breakdowns across business units, employee groups and varying AIP cap levels, and the respective allocations across business units.

B. Positions of the Parties

1. Opposition to Xcel's Proposed Changes

a. AIP Cost-Recovery Cap

XLI opposed increasing the cap on AIP recovery to 20% of base salary, arguing that doing so would increase the cost burden on ratepayers without producing ratepayer benefits sufficient to justify the cost. XLI asserted that the earnings-per-share target fundamentally aligns AIP with shareholder interests and that the performance indicators Xcel considers when making AIP payouts are not designed to keep customers' bills low.

The Department also opposed Xcel's proposal to increase the cap on AIP recovery. Although some AIP recovery may be reasonable to balance ratepayer interests with the Company's needs for furnishing utility service, the Department contended that such recovery should be limited because AIP primarily incentivizes employees to act in the interest of shareholders, and because requiring customers to pay for AIP transfers some portion of risk to customers while largely accruing benefits to shareholders. Additionally, the Department argued that AIP prioritizes short-term earnings and rewards short-term thinking, which could adversely affect customers if it factors too heavily into an employee's compensation.

Additionally, the Department opposed Xcel's request to apply the AIP cap to the aggregate of employees' salaries rather than applying it on an individual basis. The Department argued that aggregation of the cap would allow Xcel to concentrate its total AIP balance on a few employees, potentially tying their compensation too closely to shareholder interests and compromising their duties to exercise independent judgment on behalf of the Company to provide safe and reliable service. An aggregate cap could allow Xcel to fully recover 15 or 20% of all eligible employees' aggregate base pay for AIP even if most employees fail to meet their performance goals, which could further compromise incentives.

Recalculating Xcel's AIP expense to reflect a 15% individual cap, the Department recommended reducing Xcel's AIP revenue requirements by $1.127 million for 2022, $1.161 million for 2023, and $1.197 million for 2024.

b. Refunds of Unpaid AIP Amounts

The Department argued that allowing Xcel to retain unpaid incentive compensation would unjustly and unreasonably allow shareholders to offset losses with funds provided by ratepayers.

Additionally, allowing the Company to retain these amounts would functionally eliminate the purported justification for requiring ratepayers to fund this type of compensation: If AIP is not paid out, it can be inferred that the desired ratepayer benefits were not achieved; therefore, it would be unjust and unreasonable to allow Xcel to enrich itself by retaining ratepayer-funded AIP amounts that are not paid out to employees.

c. AIP Reporting Requirements

The Department contended that Xcel did not substantiate its proposal to change its AIP reporting requirements, failing to identify a burden that outweighs the benefit of such reporting. Accordingly, the Department recommended that the Commission maintain the existing reporting requirements but allow Xcel to file its proposed changes in its next AIP refund filing, with support showing why such reporting changes are appropriate and showing that the information needed to review AIP compliance would still be provided if the changes were adopted.

2. Xcel

Xcel argued that its AIP request is reasonable because its total employee-compensation request, including AIP, does not exceed market-based levels. Xcel claimed that it needs to offer employees AIP equal to more than 20% of their base pay to remain competitive in the labor market, so increasing the recoverable cap will simply reduce the amount under-recovered. Xcel rejected concerns about the earnings-per-share threshold aligning employee compensation with shareholder interests, contending that the threshold is reasonably designed to ensure that the Company has the funds to pay out AIP and that the Company's financial strength and ability to attract capital in varying economic conditions are integral to its ability to provide safe, reliable, and affordable service to customers. Additionally, Xcel argued that the key performance indicators it uses to determine AIP payouts for individual employees are aligned with customer-oriented goals.

Xcel argued that a 15% cap is no longer appropriate because the Company has changed its compensation structure consistent with industry trends. Xcel contended that past decisions upholding the 15% cap were based on a concern that AIP would result in total compensation exceeding market levels, and that this concern is no longer present because the company now treats AIP as a component of the total compensation needed to reach the targeted market median level, rather than an additional payment above market median.

Xcel noted that Minnesota Power was authorized to apply a 20% cap to its short-term incentive program in a past rate case and argued that the reasons for that decision apply equally to Xcel.[14] In defense of its proposals to aggregate the calculation of the AIP cap and to allow the Company

[14] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order at 33 (March 12, 2018).

to retain unpaid AIP amounts, Xcel argued that requiring the Company to calculate a refund at the individual level and refund amounts not paid out according to the cap hinders the Company's ability to differentiate pay among its incentive-eligible employees in a way that effectively manages performance expectations. Xcel argued that calculating the cap in the aggregate and not requiring refunds of unpaid amounts would allow the Company the flexibility necessary to allocate the total AIP budget in a way that effectively incentivizes and rewards top performance.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with the Department that it is just, reasonable, and in the public interest to limit rate-recoverable AIP because that type of compensation is contingent upon first satisfying shareholder interests. However, the ALJ was persuaded that it would be reasonable to increase the cap to 20% of base pay because market-rate compensation practices have evolved to include more incentive-based compensation in recent years. In support of this recommendation, the ALJ cited the 2018 order authorizing a 20% cap on short-term incentive compensation for Minnesota Power.[15]

The ALJ recommended maintaining the requirement to apply the cap on an individual-employee basis rather than switching to an aggregate cap. The ALJ agreed with the Department that aggregating the AIP would permit the Company to align employee incentives too closely with shareholder interests over customer interests, which would not be in the public interest. Additionally, the ALJ recommended that the Commission require Xcel to refund to ratepayers any AIP amounts not paid out as AIP compensation. The ALJ found that the reasonableness of recovering incentive compensation through rates is contingent on the incentives advancing ratepayer interests, and if incentive compensation is not paid out to employees, it is reasonable to infer that the desired ratepayer advantages were not achieved.

The ALJ also recommended that the Commission deny Xcel's proposal to modify its AIP compliance filing requirements because the proposal was not sufficiently supported in the record, but adopt the Department's suggestion to allow Xcel to propose changes to filing requirements in its next AIP refund filing.

D. Commission Action

1. AIP Cost-Recovery Cap

The Commission respectfully disagrees with the ALJ's recommendation to increase the AIP cap to 20% of base salary; instead, the Commission will maintain the cap at 15% of base salary. Although Xcel presented evidence that it uses AIP to meet, not exceed, market-based total compensation levels, and that it pays some employees AIP equal to more than 15% of their base pay to remain competitive, the Company has not met its burden to demonstrate that it would be just and reasonable for ratepayers to pay more for incentive compensation tied to an earnings-per-share threshold that primarily benefits shareholders.

AIP is not like most O&M expenses that are necessary for the provision of safe and reliable service, for which the goal in ratemaking is to identify a representative test-year figure to fully

[15] *Id.*

compensate the Company for its reasonable costs. Rather, because AIP is driven in part by shareholder interests, the Commission has consistently held that it is reasonable to limit rate recovery of AIP even if that leaves the utility's actual AIP expense partially unrecovered. In asserting that it under-recovers its actual and necessary compensation expenses with a 15% cap, the Company did not persuasively show that it is unable to adequately compensate and incentivize its employees by supplementing the rate-recoverable portion of AIP with other options available outside of rates.

The Commission finds that capping AIP recovery at 15% of the employee's base salary strikes a reasonable balance between ratepayer interests and the Company's needs for furnishing service. The Commission is not persuaded that Xcel's evidence of shifting market compensation structures is sufficient to outweigh the concerns discussed above regarding incentives and risks associated with earnings-per-share-based AIP so as to justify imposing a greater share of AIP expense on ratepayers.

The Commission also respectfully disagrees that the Commission's 2018 decision to authorize a 20% recovery cap on Minnesota Power's short-term incentive compensation supports increasing the cap to the same level for Xcel's AIP. The Commission based its decision in Minnesota Power's case in part on a finding that Minnesota Power's short-term incentive program was not shown to create skewed incentives or other public-policy concerns. Notably, unlike Minnesota Power's program, Xcel's AIP program is subject to a dispositive earnings-per-share threshold such that *no* AIP is paid out if earnings per share do not reach the target level, regardless of any other performance metrics. The Commission is therefore not convinced that Xcel's proposal is sufficiently broadly beneficial to justify a higher percentage of recovery from ratepayers.

With respect to the ALJ's recommendation to continue applying the AIP cap on an individual-employee basis rather than applying an aggregate cap, the Commission concurs and will maintain this approach. The Department persuasively argued that aggregating the cap could allow the Company to concentrate the total AIP budget on a small number of employees, a result that might inadvertently misalign employee incentives, potentially incentivizing those who earn AIP to prioritize shareholder interests and compromising their duty to exercise independent judgment on behalf of the Company to provide safe and reliable service at reasonable cost to customers. The Commission is also not persuaded that the individual application of the cap unreasonably impedes Xcel's ability to compensate and incentivize its employees.

2. Refunds of Unpaid AIP Amounts

The Commission will also adopt the ALJ's recommendation to continue requiring Xcel to refund ratepayers for any recovered AIP amounts not paid out to employees.

The reasonableness of recovering any AIP expense through rates is contingent on the incentives advancing ratepayer interests. To the extent that Xcel is not able to pay out the full authorized AIP amount based on its employees' achievement of performance goals, it can reasonably be inferred that the offering of AIP did not fully accomplish its intended benefits for customers; in such a case, it would not be reasonable to allow Xcel to retain the portion not paid out to employees at customers' expense. The requirement that the Company refund any unused AIP amounts to ratepayers provides an important protection against some of the risk-transferring concerns raised by the Department.

3. AIP Reporting Requirements

Finally, because Xcel did not adequately support its request to alter its AIP reporting requirements, the Commission will adopt the ALJ's recommendations to maintain Xcel's existing compliance filing requirements relating to incentive compensation and the associated refund and direct Xcel to provide support for any requested reporting changes in its next annual incentive compensation compliance filing.

VII. Compensation for Top 10 Highest-Paid Officers and Employees

A. Introduction

Xcel requested rate recovery of executive compensation for its top 10 highest-paid officers and employees through a combination of base salary, pension and other benefits, annual incentive pay, and two out of three long-term incentive programs.

The rate-recoverable components of compensation for Xcel Energy Inc.'s top executives are allocated among its various operating subsidiaries and to customers located in different states within those subsidiaries based on jurisdictional percentage allocators. The NSP–Minnesota electric jurisdiction (which also includes North Dakota and South Dakota) is allocated approximately 37% of recoverable compensation expenses for shared Xcel Energy executives, and Minnesota customers are allocated about 87% of the NSP–Minnesota electric share.

Xcel proposed that Minnesota electric customers pay approximately $7.05 million for compensation of Xcel Energy's 10 highest-paid executives for the 2022 test year, $7.57 million for 2023, and $7.88 million for 2024. These amounts are in addition to the compensation those 10 individuals receive from customers in other jurisdictions and from non-rate-recoverable components such as long-term incentive programs and AIP above applicable percentage-of-base-salary caps.

Xcel stated that it generally aims to set non-bargaining employee compensation at a level consistent with the median for comparable positions to remain competitive in the labor market.

While the ALJ did not directly address the issue of top-10 executive compensation and no formal party commented on it, the Commission received comments from members of the public stating that it would be unreasonable for ratepayers to pay such levels of compensation for Xcel's executives, particularly as many Minnesotans face continuing economic challenges including widespread inflation in the costs of necessities such as food, fuel, and medical expenses; ongoing surcharges and high market prices for natural gas related to extreme weather and market events; and lasting effects of the COVID-19 pandemic on individual incomes and on the broader economy.

For example, two members of the public, commenting jointly, stated:

> CEO compensation is also a sore spot during these days when most of us are watching our dollars closely. In 2021 alone Xcel paid compensation of about $20.5 million (combined for current and previous CEO). It takes a lot of homeowners paying their monthly

> bills to cover this cost. During these times of oppressive cost increases on just about all the basics in our lives, we need the Public Utilities Commission to acknowledge that these increases are an excessive burden on customers.[16]

Characterizing Xcel's executive compensation as "exorbitant" and stating that its CEO was one of the highest-paid CEOs in Minnesota and the highest paid among the state's utilities, another commenter recommended that the Commission reduce the amount of executive compensation included in rates rather than increase the financial burden on customers.[17]

Multiple members of the public further questioned the reasonableness of Xcel's executive compensation structure and increasing rates to fund it, asserting that Xcel had the eighth highest-paid CEO in Minnesota and the second highest CEO-to-median-worker pay ratio among U.S. utilities (139:1) in 2020.[18]

B. Commission Action

The Commission is not persuaded that Xcel has met its burden to show that requiring ratepayers to pay for top-10 executive compensation at the full proposed levels is reasonable.

Minnesota law requires the Commission to review costs related to a utility's highest-paid executives closely,[19] and several factors warrant a closer examination in this case. In particular, in this proceeding, Xcel initially requested rate increases of $677.72 million. While Xcel has moderated its request over the course of the proceeding, its final request is still one of the largest rate-increase proposals the Commission has ever considered. Further, through multiple rate cases and multiyear rate plans, the Company has increased its rates nearly every year for the past decade, such that ratepayers are paying hundreds of millions in increased rates compared to 10 years ago.[20]

[16] Comment of James and Katherine Anderson (October 27, 2022).

[17] Comment of Nanette Echols (November 14, 2022).

[18] Comment of Joan Pasiuk (November 28, 2022); comment of Janet Pope (January 5, 2023).

[19] *See* Minn. Stat. § 216B.16, subd. 17(5) (requiring utility to file a schedule separately identifying costs for its 10 highest-paid executives).

[20] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order (June 12, 2017) (approving settlement agreement to increase rates by $244.721 million over 2016–2019); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order (May 8, 2015) (authorizing rate increases of approximately $58.908 million in 2014 and $105.854 million in 2015); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order (September 3, 2013) (approving rate increase of $102.797 million for 2013). *See also In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Order Approving True-Up Adjustments (August 5, 2022) (approving Xcel's 2021 sales true-up surcharge of $59.427 million as part of stay-out proposal); *In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of True-Up Mechanisms*, Docket No. E-002/M-19-688, Order

Further, as discussed above, the Commission received more than 20 public comments expressing dissatisfaction with the high level of compensation paid to Xcel's executives and many more comments discussing financial impacts the proposed rate increase would have on ratepayers.[21] These comments illustrate the difficulties consumers are facing and raise concerns about the reasonableness of the Company's executive compensation request. In light of these considerations, a closer review of Xcel's proposal for recovery of top-10 executive compensation expense is warranted.

Based on this record, the Commission concludes that Xcel has not demonstrated that full recovery of its proposed top-10 executive compensation would result in just and reasonable rates.

Xcel's primary justification for its executive compensation costs was that its employee compensation levels are based on a market comparison to other firms that compete with Xcel for employees. In this case, the Commission finds that argument unpersuasive.

First, the market comparison that Xcel conducted is based on other corporate officers, all of whom have a fiduciary duty of care to shareholders—but no comparable duty to ratepayers. While it may benefit shareholders to compensate Xcel's executives at the same level as profit-maximizing executives at other firms, the Commission is not persuaded that comparison is reasonable for setting rates in this case. Xcel has not provided a persuasive argument for why ratepayers should bear the full requested cost of market-based corporate compensation.

Second, the shareholder focus of Xcel's executive compensation package is further demonstrated by Xcel's AIP and LTI programs, discussed above, which closely tie overall executive compensation to shareholder earnings. That compensation structure focuses the executive team on shareholder benefits, which are not necessarily aligned with the interests of ratepayers.

Third, it does not appear that the Company meaningfully considered the impact of this high cost on ratepayers or explored the possibility of reducing any component of the executive compensation packages it offers as a means of shouldering the burdens of inflation alongside its customers.

Approving Implementation of Sales True-Up Adjustments (June 28, 2021) (authorizing Xcel to implement 2020 sales true-up surcharge of $119.4 million as part of stay-out proposal).

[21] *See, e.g.*, Comment of Araceli Morales (October 16, 2022); comment of Pangea Carpio-Evans (October 21, 2022); comment of Lydia McAnerney (October 26, 2022); comment of James and Katherine Anderson (October 27, 2022); comment of Angelina McDowell (November 2, 2022); comment of Claudia Furlong (November 4, 2022); comment of Nanette Echols (November 14, 2022); comment of Joan Pasiuk (November 27, 2022); comment of Robert Frank (November 28, 2022); comment of Josiah Gregg (November 29, 2022); comment of Tracy Kugler (December 4, 2022); comment of Catherine Day (December 6, 2022); comment of Joy Anderson (December 8, 2022); comment of Maia Homstad (December 9, 2022); comment of Mike Skucius (December 9, 2022); comment of Tim Ballman (December 13, 2022); comment of Sue VanZanden (December 15, 2022); comment of Joshua Lewis (December 16, 2022); comment of Lori Belz (December 27, 2022); comment of Catherine Early (January 4, 2023); comment of Janet Pope (January 4, 2023).

As with all rate-increase requests, the Commission has an obligation to both verify that the amount of costs is accurate and evaluate whether, based on the facts in the record and the application of its judgment, it is just and reasonable to include the cost in rates. In the Commission's judgment, Xcel has not made that showing in this case.[22]

Having concluded that Xcel's full request for recovery is not reasonable, the Commission must determine what level of recovery is appropriate. On this record, the Commission concludes that it would be reasonable for Xcel's ratepayers to pay an amount for Xcel's top 10 executives that is comparable to the amount they pay for their own executives in state government. Beginning in 2024, Minnesota's highest executive officer—its Governor—will be paid approximately $150,000 per year. The Commission finds that allowing recovery of compensation at a level similar to that of Minnesota's top executive on average for each of Xcel's 10 highest-paid executives reasonably reflects the level of expense that should be borne by ratepayers.

The Commission will therefore limit the level of executive compensation for the top 10 highest-paid employees and officers recoverable through Minnesota electric rates to $1.5 million per year in total. This decision also precludes Xcel from recovering any AIP expense for its 10 highest-paid officers and employees.

The Commission will require Xcel to calculate the Minnesota jurisdictional revenue-requirement adjustments resulting from these limitations on top 10 executive compensation and to file the calculations both in this docket and in the annual incentive compensation plan docket.

On this issue as with other compensation-related issues, the Commission's decision is limited to the amount of compensation costs that Xcel may include in its rates charged to Minnesota customers. The Company has been and continues to be free to compensate its employees at levels in excess of its authorized rate recovery if it chooses to do so.

VIII. Prepaid Pension Asset

A. Introduction

Xcel makes contributions to its pension plan to ensure adequate funding for future employee-benefit obligations. Since the pension plan's inception, the Company has contributed more to the plan than it has recognized in its actuarially calculated pension expense recovered from ratepayers. Xcel refers to the positive net balance resulting from the cumulative difference between its annual pension expense amount and the annual contributions made by shareholders to the qualified pension trust since it began offering the benefit as its "prepaid pension asset."

Xcel seeks to include a prepaid pension asset of approximately $167.3 million, less $46.8 million in accrued liabilities for retiree medical and post-employment benefits (discussed below), in rate base so it can earn a return on the net amount. The net total of the prepaid pension asset and

[22] The Commission's conclusion is further supported by the fact that Xcel failed to file its top-10 executive expenses with its initial case, as required by Minn. Stat. § 216B.16, subd. 17. While Xcel stated that it provided courtesy copies of the expenses to the Commission, the Department, and the OAG, it is undisputed that the required information was not filed until the final days of the proceeding, and that other parties and the public did not have required opportunity to review Xcel's top-10 executive expenses.

accrued liabilities, which Xcel proposes to add to rate base, is approximately $95.4 million for 2022, $102.2 million for 2023, and $117.0 million for 2024.

B. Positions of the Parties

1. Xcel

Xcel requested that its net prepaid pension asset be included in rate base because it arose due to factors beyond the Company's control, including heightened funding requirements due to the federal Pension Protection Act and increasing pension liability due to the Federal Reserve's actions to reduce interest rates to stimulate the economy.

According to Xcel, this is an asset fully funded by shareholders that benefits customers by solidifying the status of the Company's pension plan, thereby helping Xcel to attract and retain the employees necessary to provide safe and reliable service. Xcel asserted that customers receive financial benefits in the form of significantly lower rates because shareholders have funded this prepaid pension asset and that any investment income from the shareholder-funded prepaid pension asset is passed on to ratepayers.

Xcel contended that rejecting the request for a return on prepaid pension asset would disincentivize the Company from contributing more than the minimum required amounts to its pension plan each year, which would negate the financial benefits to customers noted above.

Alternatively, Xcel argued that, if it is not authorized to earn a return on prepaid pension asset, it should be permitted to recalculate its pension expense without including the expected return on prepaid pension asset. Xcel argued that such a recalculation would avoid the inequity of customers effectively earning a benefit in the form of reduced pension expense reflected in rates without customers paying corresponding compensation to shareholders for their prepayment.

2. The Department

The Department opposed Xcel's request to earn a return on its prepaid pension asset, stating that Xcel's request is not consistent with Generally Accepted Accounting Principles or any current accounting standards.

Asserting that rate base is intended to provide a return on the total investment in, or fair value of, the facilities a utility employs in providing service, the Department argued that the prepaid pension asset does not fit within that principle. As opposed to a true asset used in providing service, the Department characterized the prepaid pension asset as essentially a temporary accounting difference resulting from quirks of applying differing accounting schemes to pension contributions and expenses, which does not warrant inclusion in rate base.

The Department cited the following additional reasons for denying a return on the prepaid pension asset:

- Utilities already recover allowable pension expense from ratepayers through O&M costs.

- Unlike the kinds of assets on which utilities are traditionally entitled to earn a return, the prepaid pension asset is nontangible and temporary in a way that cannot be accounted for like the depreciation and capital additions of tangible assets.

- Unlike other prepaid assets, the prepaid pension asset fluctuates depending on funding, market conditions, and amendments to the plan.

- The asset already earns a return in the form of investment returns.

- Including the prepaid pension asset in rate base would earn a return on out-of-test-year expenses for which the Commission has not authorized deferred accounting.

- Characterizing this amount as an asset is misleading because it does not account for the funding status of the entire pension plan; in fact, as of the end of 2021, Xcel's NSPM pension plan was underfunded by approximately $240 million.

- It would be impracticable to separate the prepaid amount attributable solely to the utility's contributions from that attributable to ratepayer contributions and market returns, so it cannot be shown that the asset is fully funded by shareholders.

Further, the Department opposed Xcel's alternative request to recalculate its pension expense without including the return on prepaid pension asset if the Commission excludes this item from rate base. The Department asserted that Xcel did not provide sufficient explanation or support for its recalculations, which show substantial revenue-requirement increases between $7.9 million and $9.1 million in each year of the rate plan. Further, the Department argued that allowing Xcel to recalculate its pension expense would advantage Xcel over other Minnesota utilities that have not been afforded the same opportunity.

3. XLI

XLI opposed Xcel's request to earn a return on its prepaid pension asset for substantially the same reasons raised by the Department. XLI emphasized that it is impossible to determine the funding sources of the prepaid pension asset reliably from the record and noted the statutory standard that any doubt as to reasonableness is to be resolved in favor of the consumer.

Additionally, XLI recommended against allowing Xcel to recalculate its qualified pension expense without applying the expected return on the prepayment portion of the trust because Xcel raised this alternative proposal late in the proceedings, limiting other parties' opportunity to review and respond to the proposal,[23] and because Xcel did not adequately support its request with persuasive evidence and argument.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny Xcel's proposal to include a prepaid pension asset in rate base, finding that Xcel had not met its burden to show that it would be reasonable to

[23] Xcel briefly raised this argument in rebuttal testimony, but the issue was not addressed again by any party until a statement in Xcel's post-hearing reply brief that did not include a citation to the record. (Schrubbe Rebuttal at 32; Xcel Reply Brief at 46.)

do so. The ALJ agreed with the Department that Xcel's prepaid pension asset request is not consistent with Generally Accepted Accounting Principles and other guidance and that there is doubt with respect to the source of the asset's value because it is determined in part by market gains and losses. Additionally, the ALJ found that Xcel has not adequately justified deferred accounting for any surplus shareholder contributions exceeding the pension expense amounts approved for rate recovery.

However, the ALJ recommended that the Commission allow Xcel to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates.

D. Commission Action

The Commission concurs with the ALJ, the Department, and XLI that Xcel has not justified rate-base treatment of its prepaid pension asset. Accordingly, the Commission will require the Company to remove the prepaid pension asset from rate base.

In previous rate cases, the Commission has rejected the inclusion of prepaid pension asset in rate base because it is distinct from assets typically included in rate base. It already earns a return in the form of investment returns, it fluctuates in value, and it is misleading in that it does not account for the funding status of the entire pension plan. Pension-plan assets and benefit obligations fluctuate up and down depending on funding, market conditions, and amendments to the plan. The balances in the prepaid pension asset are temporary and fundamentally different from typical rate-base assets on which the Company earns a return. The Commission concludes that this reasoning is still sound.

Xcel has not pointed to any accounting requirements, rules, or laws that require prepaid pension assets to be included in rate base and earn a return; instead, the Company appears to argue simply that it would be reasonable for the Commission to allow such treatment. To the extent any party has pointed to specific requirements rather than policy preferences, the Department has raised valid concerns about whether Xcel's accounting proposal would be consistent with Generally Accepted Accounting Principles.

Minnesota law requires that Xcel be allowed to earn a return on its rate base and provides the following description of how rate base should be calculated:

> In determining the rate base upon which the utility is to be allowed a fair rate of return, the commission shall give due consideration to evidence of the *cost of the property* when first devoted to public use, to *product acquisition cost* to the public utility less appropriate depreciation on each, to c*onstruction work in progress*, to offsets in the nature of capital provided *by sources other than the investors*, and to other expenses of a capital nature.[24]

When evaluating what type of costs should be allowed to earn a return, this statutory language directs the Commission's attention to capital property that is acquired by the utility, which

[24] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

depreciates over time, and which is constructed. "Other expenses of a capital nature" likewise reflects a focus on longer-term investments as distinct from operating expenses. While the requirement to give "due consideration" does not prohibit the Commission from including other types of expenditures in rate base, as it has done for some other non-capital assets, the Commission is not persuaded that it would be reasonable to do so for the prepaid pension asset. Based on the record, the Commission finds that Xcel's prepaid pension asset is fundamentally different from capital expenditures and other allowed rate-base categories and that Xcel has not demonstrated it would be just and reasonable to allow a return on the prepaid pension asset.

Further, the Commission finds persuasive testimony of the Department's expert witness that the two components of the prepaid pension amount—actuarially determined pension expense and pension contributions—can vary significantly from year to year depending on actuarial assumptions and the Company's decisions in any given year about whether to contribute more than the legally required minimum amount. Not only can a prepaid pension asset fluctuate over time, but the asset is temporary in that a change in market returns, legally required minimum contributions, or actual contributions can turn the asset into a liability. At a minimum, the testimony and arguments raise doubts about the amount and permanence of the prepaid pension asset. The Commission is to resolve those doubts in favor of ratepayers.

The Commission finds that Xcel's arguments are unpersuasive, and that the Company has failed to carry its burden to prove that its proposed ratemaking treatment of its prepaid pension asset would result in just and reasonable rates.

The Commission respectfully disagrees with the ALJ's recommendation to allow Xcel to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust. Although Xcel noted the results of its recalculations in a spreadsheet comparing the impacts of the ALJ's and parties' recommendations on the revenue requirement, the Company did not provide sufficient details to explain how it arrived at these adjusted totals or support the reasonableness of the proposed adjustments. Further, Xcel did not introduce this proposal until late in the proceedings, and parties therefore had a limited opportunity to respond. Based on the limited record on this issue, the Commission is not persuaded that Xcel met its burden to support its request. Therefore, the Commission will not allow Xcel to reflect its recalculated qualified pension expense in rates.

IX. Accrued Liabilities for Retiree Medical and Post-Employment Benefits

A. Introduction

Over the life of its retiree medical and post-retirement benefits plans, Xcel has recovered from customers more than it has contributed to those plans, resulting in unfunded liabilities. Xcel sought to include these accrued liabilities in rate base along with its request to include prepaid pension asset in rate base, discussed above.

B. Positions of the Parties

Xcel acknowledged that its accrued liabilities for retiree medical and post-retirement benefits should be treated consistently with the prepaid pension asset. The Company's reasoning for including these liabilities in rate base echoed its reasons for its prepaid-pension-asset request, discussed above.

The Department and XLI opposed Xcel's request to include these accrued liabilities in rate base for the same reasons they opposed including the prepaid pension asset in rate base—largely because these balances are distinct from traditional rate-base assets in multiple ways, as discussed above.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny Xcel's request to include in rate base accrued liabilities for retiree medical and post-employment benefits, for the same reasons discussed above related to excluding prepaid pension asset from rate base.

D. Commission Action

The Commission agrees with the ALJ and the parties that accrued liabilities for retiree medical and post-employment benefits should be treated the same as prepaid pension asset for purposes of this rate case. Like the prepaid pension asset, these accrued balances are fundamentally different from typical rate-base assets in that they represent the cumulative difference between expenses and contributions, they fluctuate in value, and they are difficult to estimate accurately. Accordingly, having decided to exclude prepaid pension asset for the reasons discussed above, the Commission will also adopt the ALJ's recommendation to exclude from rate base accrued liabilities for retiree medical and post-employment benefits for the same reasons.

X. Energy Supply Operations and Maintenance Expenses

A. Introduction

Xcel's energy supply business area is responsible for operating and maintaining the Company's non-nuclear generation portfolio, managing capital construction projects, overseeing environmental compliance, and supporting the coordination of generating-unit dispatch with Midcontinent Independent System Operator, Inc. (MISO). Xcel's energy supply O&M budget reflects the costs to operate and maintain the Company's non-nuclear generating facilities on a day-to-day basis, including labor, chemicals, materials, outside services, rents, land easements, and employee expenses. In developing its energy supply O&M budgets, Xcel reviews historical costs and factors in anticipated changes such as changes to plant operating profiles, new and retiring generation, overhaul schedules, and plant improvements.

Xcel proposed the following budgets for energy supply O&M expense: $154.6 million for 2022, $160.8 million for 2023, and $157.7 million for 2024.

Xcel's proposed average energy supply O&M budget for the years 2022–2024 is 13.8% higher than its average yearly budget over 2018–2020, and between 8.8% and 12.8% over its 2021 actual expense. Xcel asserted that the primary drivers of this increase are new wind farm O&M contracts and land easement payments.

B. Positions of the Parties

1. The Department

The Department argued that Xcel did not meet its burden to prove its requested energy supply O&M expense is just and reasonable. Raising a concern that utilities have an incentive to overestimate expenses in test years to secure higher rates and then cut corners on actual spending between rate cases to increase profits, the Department argued that Xcel has not met its burden to prove that its test-year budgets are representative of actual needs and not overestimated for profit-inflating purposes.

As possible evidence of this incentive having led Xcel to overestimate costs to inflate rates, the Department asserted that Xcel has over-forecasted its energy supply O&M expense by between $6.0 million and $28.2 million each year between 2016 to 2021 and, since 2016, has collected $97.6 million more from ratepayers than it actually spent on this expense category. The Department also questioned the reasons for year-to-year volatility in the Company's 2016–2021 energy supply O&M expenses.

The Department disputed some of Xcel's claimed drivers of the increase in forecasted energy supply O&M expense. For example, the Department challenged Xcel's assumption of a 3% increase in internal labor costs because the employee headcount is forecasted to decrease after 2022. Additionally, the Department contended that Xcel's retirement of Unit 2 of the Sherburne County Generation Facility (Sherco 2) in 2023 did not appear to be sufficiently accounted for. Based on its analysis that Xcel did not meet its burden, the Department recommended reducing the energy supply O&M expense by $5.3 million in each year, which is equal to the amount Xcel over-collected in the Minnesota jurisdiction in 2021. The Department argued that reducing Xcel's budget by $5.3 million each year would reasonably approximate a representative amount of energy supply O&M expense to sustain Xcel's normal operations.

2. Xcel

Xcel criticized the Department's analysis as simplistically looking backward at past costs rather than evaluating the Company's current generation portfolio. In response to assertions that Xcel has historically over-forecasted this expense category, the Company argued that its generation fleet underwent significant unanticipated changes after budgets were created for its 2016 rate case, including transitioning two of the Company's coal-fired generating plants from year-round to seasonal operation in 2020.

Of the $6.5 million difference between Xcel's forecasted and actual energy supply O&M expense for 2021, the Company attributed $5.5 million to liquidated damage payments received from wind turbine manufacturers that ultimately flowed back to customers through the renewable energy standard (RES) rider. Xcel argued that these payments could not have been forecast in advance because they are dependent on each wind facility's actual performance in a given year. Therefore, Xcel argued that these historical variations in forecasted and actual expense do not call into question the reasonableness of the Company's accounting practices.

Xcel argued that year-to-year fluctuations in its energy supply O&M expenses are primarily due to planned major overhauls at the Company's coal and natural gas facilities, which are essential to keeping the facilities running efficiently, safely, and in compliance with regulations. Xcel stated that in years with planned major overhauls, O&M expenses increase for internal labor, contract labor, and materials needed to complete these overhauls. Further, Xcel stated that the addition of new renewable generation also contributes to year-to-year O&M cost fluctuations. Xcel asserted that its forecast assumed reductions of 51 full-time-equivalent employees between 2022 and 2024 and accounted for the retirement of Sherco 2, so these changes do not support further reducing energy supply O&M recovery as the Department suggested. Xcel noted that the retirement of Sherco 2 may not lead to a net reduction in O&M costs because the Company will need to replace Sherco 2's generation through increased dispatch of other units or adding new generation facilities.

Further, Xcel argued that the Department's recommended reduction of $5.3 million per year is unreasonable because Xcel's energy supply O&M expenses have increased since it created its budgets in this rate case for the following reasons: (1) inflation, (2) wage increases for collective bargaining employees due to new agreements with unions, (3) the proposed life extension of wind facilities, and (4) year-round rather than seasonal operation of the King and Sherco 2 coal facilities in 2022–2023.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel met its burden to establish that its forecasted energy supply O&M budget is just and reasonable. The ALJ did not concur with the Department's rationale that the Company's over-recovery in past years justifies denying recovery of the forecasted amounts in this case. The ALJ found that Xcel's prior over-recoveries were largely attributable to events the Company could not reasonably have anticipated, while its 2022–2024 forecast appears to be reasonably calculated based on realistic projections of anticipated costs of furnishing service, which the Department did not persuasively dispute. The ALJ therefore recommended that the Commission allow Xcel to recover its proposed energy supply O&M expenses without the Department's adjustment.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve recovery of Xcel's energy supply O&M expenses totaling $154.6 million, $160.8 million, and $157.7 million for 2022, 2023, and 2024, respectively. Xcel described in detail how it developed each component of the budgets and why the budgeted amounts were reasonable and necessary to support the operation and maintenance of the Company's generation facilities. Xcel also offered reasonable explanations for the increases in these costs over previous years and variations between forecasted and actual energy supply O&M expense in past years.

XI. Business Systems Operations and Maintenance Expenses

A. Introduction

Xcel's business systems O&M budget includes costs related to the operation and maintenance of information technology (IT) services across Xcel Energy, including software systems, computers, printers, phones, radio systems, servers, annual software contract and license fees, and maintenance agreements for existing software and hardware. This expense category also includes non-capitalized costs associated with developing, enhancing, and maintaining new or existing IT systems.

Xcel's proposed business systems O&M budget for the Minnesota electric jurisdiction is $89.9 million in 2022, $96.2 million in 2023, and $103.8 million in 2024, exclusive of the Advanced Grid Intelligence and Security (AGIS) costs being recovered separately through the Transmission Cost Recovery rider.

B. Positions of the Parties

1. The Department

Noting that Xcel's requested business systems O&M budget for 2022–2024 reflects a 32.2% growth rate over 2021 actual spending in this category, the Department argued that the Company has not met its burden to justify the substantial increase. The Department argued that Xcel's requested increase is inconsistent with the Company's own historical expense, which averaged $77.2 million in this category each year from 2018–2021.

The Department also stated that Xcel has a history of over-forecasting its business systems O&M expense and raised concerns about utility incentives to overestimate test-year O&M budgets to inflate rates, only to cut spending in an attempt to increase profits between rate cases. For example, Xcel's actual 2021 expense in this category was 16% lower than projected.

Further, the Department claimed that Xcel's proposal significantly deviates from IT spending trends in the industry. The Department cited a 2021 report stating that IT budgets were expected to increase by an average of 3.1% in North America or 3.6% worldwide, which is much lower than Xcel's requested 14.5% increase for 2022.

The Department analyzed some of the individual programs and expenses Xcel claimed were driving costs in this category but determined that the data did not adequately explain the requested overall increase.

Based on its analysis that Xcel did not meet its burden to justify its requested costs, the Department recommended that the Commission reduce the Company's recovery in this category to an annual amount based on Xcel's actual business systems O&M expense for 2021, adjusted to reflect continued inflation at a high rate of 7.5% over 2021 actuals in 2022, 7.5% in 2023, and 7.0% in 2024. The Department's proposed adjustments would reduce Xcel's revenue requirement by $5.5 million in 2022, $5.5 million in 2023, and $6.9 million in 2024.

2. Xcel

Xcel contended that its proposed business systems O&M budget reflects the reasonable costs of the Company's growing needs for IT services and is representative of the level of business systems O&M necessary to support an appropriate level of service to the Company's customers year over year. Xcel stated that its customers have benefited from lower IT costs in past years but that technology investments are now necessary to ensure safe and reliable service. It stated that investments in technology help the Company's other business areas to maintain and enhance the quality of service to customers.

Xcel attributed much of the overall budget increase to rising software license and maintenance costs, company labor costs, shared assets costs, and network services costs, in addition to necessary updates to address cyber security concerns and other vulnerabilities.

Xcel described the need for some specific components adding costs to this category, including the need to maintain the new General Ledger and Work and Asset Management system, which was a significant undertaking as part of the Company's Productivity Through Technology initiative. Xcel also explained new capital projects such as the Digital Operations Factory, Customer Enhancements including the Customer Experience program, and the Core Human Resources Application project, which also added costs to the business systems O&M budget. Xcel asserted that no party challenged the reasonableness of undertaking any of these IT projects.

Opposing the Department's proposed adjustments, Xcel argued that the Department's analysis unreasonably focused on historical trends and did not adequately consider, or effectively dispute, Xcel's explanations for the factors driving these costs and the reasons why the costs are higher and increasing at a faster rate than in past years. Xcel contended that the Department failed to identify any unreasonable cost associated with any particular business systems capital investment or O&M expense to support its criticism of the overall budget, and that it would be unreasonable to disallow any of these costs even though they are associated with reasonable investments solely on the ground that overall spending in this category is higher than it has been in past years.

To the extent that the Department analyzed some individual projects and budget items, Xcel argued that the Department's analysis is of limited value because it did not account for all of the new capital projects and other factors driving business systems O&M costs.

Xcel challenged the applicability of the report the Department cited regarding IT spending growth rates, noting that they pertained to worldwide IT spending forecasts and were not specific to similarly situated U.S. utilities or O&M spending forecasts.

Xcel argued that the Department's recommendation to set the budget at the level of the Company's 2021 actual business systems O&M spending, adjusted for inflation, is not sufficiently tied to any analysis of the reasonableness of the Company's costs and is not supported by the record. Further, Xcel argued that the Department's proposed inflation rates of 7.5% and 7.0% are not supported by evidence. Xcel countered that the Department's suggested inflation rate for 2022 is below the level reflected in the record and, therefore, would result in rates insufficient to recover rising costs for new purchases even without the addition of new projects and other drivers of cost increases.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Xcel met its burden to demonstrate that its proposed business systems O&M costs are reasonable. The ALJ found that Xcel persuasively explained the drivers for its claimed costs and showed how these investments are necessary to maintain and enhance service to customers. The ALJ found that the Department's analysis, which focused on historical and industry trends in IT spending growth generally, did not adequately consider or rebut the reasonableness of the specific cost-driving factors or the accuracy of the associated costs Xcel established in the record. Nor did the Department persuasively demonstrate the reasonableness of its proposed alternative budget based on 2021 actual costs and inflationary adjustments, in the ALJ's view. The ALJ therefore recommended that the Commission allow Xcel to recover its proposed business systems O&M expenses without modification.

D. Commission Action

The Commission concurs with the ALJ that Xcel has met its burden to show that its proposed business system O&M costs are reasonable. The record contains substantial evidence supporting both Xcel's cost estimates and the need for and reasonableness of the underlying investments to enable the Company to maintain and enhance its provision of service to customers. The Commission will therefore approve Xcel's Minnesota jurisdictional business systems O&M expenses of $89.9 million for 2022, $96.2 million for 2023, and $103.8 million for 2024.

XII. Income-Tax Tracker Amortization

A. Introduction

Xcel requests to collect approximately $6.9 million in income tax and interest that the Company paid for the tax years ending in 2010–2016 following IRS audits that concluded in 2017, 2018, and 2020. Amortized over the three-year rate plan, Xcel proposes to recover $2.492 million in 2022, $2.300 million in 2023, and $2.110 in 2024 for these post-audit tax liabilities.

Generally, when determining a utility's revenue requirement in a rate case, the Commission evaluates the utility's investment in capital assets, operating revenues, and operating expenses based on a representative test year (or in the case of an MYRP like this one, a specific set of recent or forecasted test and plan years). Generally, the operating expenses are limited to those expenses forecasted to be incurred in the designated test and plan years.

To recover out-of-test-year expenses, a utility generally must petition for approval to use deferred accounting. Deferred accounting is a regulatory tool that allows a utility to postpone the standard accounting treatment otherwise required for a particular item by tracking out-of-test-year expenses and seeking recovery in a future proceeding. Deferred-accounting requests are subject to Commission discretion and are granted only upon a showing of good cause.[25]

Historically, the Commission has permitted deferred accounting in unusual cases where utilities incur out-of-test-year expenses that, because they are unforeseen, unusual, and large enough to have a significant impact on the utility's financial condition, should be eligible for possible recovery in the next rate case. Deferred accounting has also been permitted when utilities have incurred sizeable expenses to meet important public-policy mandates.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission deny Xcel's request because the Company has not received authorization to defer these out-of-test-year tax expenses. In the 1992 Rate Case

[25] Minn. R. 7825.0300, subp. 4.

Order, the Commission explicitly required Xcel to petition for deferred-accounting status of tax credits and debits at the time when final decisions are received on disputed items.[26]
The Department argued that Xcel's current request is untimely because the Company received the audit decisions in 2017, 2018, and 2020, but did not promptly petition for deferred accounting upon any of those final decisions. The Department argued that requiring utilities to petition for deferred accounting as soon as they know of additional costs provides important protections for ratepayers, as rate cases are already large and complex undertakings and the petition process allows the Commission to maintain a greater degree of control over the items deferred to a given rate case.

The Department argued that, if advance petitions for deferred accounting were not required, it would be easier for utilities to exploit rate cases as opportunities to reach back into past years and attempt to collect costs of furnishing past service from current ratepayers who may not have benefited from those past expenditures, on top of the rates that were approved and in effect during the past years. This would raise concerns both about (1) the intergenerational inequities of requiring current customers to pay for the costs of providing past service that did not benefit the current customers and (2) the reasonableness of allowing utilities to recover unanticipated out-of-test-year expenses when they presumably would not be required to refund any unanticipated surpluses.

Further, asserting that customers paid Xcel significantly more for income tax than the Company remitted to taxing authorities from 2010–2021, the Department argued that Xcel has not shown that the requested amounts have not already been collected through rates.

2. Xcel

Xcel claimed that it was not required to petition for deferred accounting immediately at the conclusion of each audit because there has been a historical practice of including income tax in rate cases. The Company contended that its filing initiating this rate case was its first opportunity to request recovery of these costs since its last rate case was filed in 2015.

Xcel argued that deferred accounting is appropriate in this case because no party disputes the amount of tax-audit credits and debits the Company seeks to recover and because income-tax audits are beyond the Company's control and their timing and outcomes are unpredictable. Additionally, Xcel argued that public policy supports deferred recovery of these costs because the post-audit tax and interest expenses arose out of Xcel's prudent efforts to keep income tax low during the relevant tax years. Xcel argued that denying its request would deter the Company from aggressively pursuing its options to minimize tax liability under the tax code. Xcel implied that, if it knew it could not defer these expenses, its incentive would be to not pursue arguable tax-reduction options and instead to pay the highest possible tax amount and pass that cost on to customers, rather than risk unrecoverable out-of-test-year tax liability after a future audit.

Finally, the Company disputed the claim that Xcel already recovers more income-tax expense from customers than it pays to taxing authorities, asserting that any difference between taxes recovered from customers before they are paid to the government reduces rate base, so customers are not ultimately charged more for taxes than the Company incurs.

[26] 1992 Rate Case Order at 58.

C. Recommendation of the Administrative Law Judge

The ALJ found Xcel's arguments unpersuasive. She found that, before the Company initiated this rate case in September 2021, it had more than a year in which it could have petitioned the Commission to approve deferred accounting for the last-resolved of the audits, which had a final decision in second quarter 2020, and several years for the other audits which were resolved in 2017 and 2018. Finding that Xcel offered no satisfactory explanation for failing to request deferred-accounting authorization at the time the audit decisions were issued, the ALJ declined to consider the merits of Xcel's untimely deferred-accounting request based on her determination that to do so would be inconsistent with the 1992 Rate Case Order.

The ALJ therefore recommended that the Commission deny Xcel's request to recover costs arising from the income-tax audits for the tax years ended 2010–2016 and adopt the Department's corresponding reductions to the revenue requirement.

D. Commission Action

The Commission concurs with the ALJ and will therefore deny recovery of the costs arising from income-tax audits for the tax years ending in 2010–2016, thus requiring Xcel to remove the corresponding $2.492 million, $2.300 million, and $2.110 million from its revenue requirements for 2022, 2023, and 2024, respectively.

These are out-of-test-year expenses for which Xcel failed to timely petition for deferred-accounting authorization. Requiring utilities to petition for deferred accounting in advance helps the Commission to maintain control over the items deferred to a given rate case to ensure that all issues receive due attention—including consideration of customer impacts and the public interest—in large and complex rate-case proceedings.

Moreover, considering the potential for intergenerational inequities and concerns about the equity of utilities generally using deferred accounting to track increases but not decreases in costs outside of a rate case (thus likely benefiting the utility over ratepayers), the Commission is not persuaded that there is good cause to grant an exception to accounting standards for these expenses on this record.

XIII. South Dakota Aurora Cost Amortization

A. Introduction

In proceedings stemming from Xcel's 2010 resource plan, the Commission required Xcel to negotiate a power-purchase agreement for the Aurora Solar Project, finding it appropriate for Xcel's system.[27] The Commission approved a power-purchase agreement (PPA) between Xcel and Aurora Distributed Solar, LLC (Aurora), relating to the Aurora Solar Project.[28]

[27] In the Matter of the Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need, Docket No. E-002/CN-12-1240, *Order Directing Xcel to Negotiate Draft Agreements with Selected Parties* (May 23, 2014).

[28] *In the Matter of the Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Docket No. E-002/CN-12-1240,

In a settlement stipulation negotiated between Xcel and the South Dakota Public Utilities Commission (SDPUC) staff, Xcel agreed not to recover the actual costs of the Aurora Solar PPA from South Dakota ratepayers. Instead, Xcel agreed in the settlement to limit its recovery from South Dakota customers to an energy proxy price derived from the system average cost of fuel and purchased power with no capacity component.

In this rate case, Xcel requests to recover from Minnesota customers the portion of the Aurora Solar PPA cost that it agreed not to recover from South Dakota customers under the SDPUC settlement. As proposed, the Company would recover the difference between the PPA price and the SDPUC-approved proxy price from January 1, 2017, to January 1, 2024, to be amortized over a two-year period. Then, beginning January 1, 2024, Xcel requests to include this portion of Aurora Solar PPA costs in its Fuel Clause Adjustment Rider so it may continue collecting the unrecovered South Dakota costs from Minnesota customers.

The Commission previously denied a similar request relating to the North Dakota share of Aurora Solar PPA costs. In 2015, after the North Dakota Public Service Commission (NDPSC) denied Xcel's request to recover the North Dakota jurisdictional share of Aurora Solar PPA costs from North Dakota ratepayers, Xcel requested approval to recover these North Dakota costs from Minnesota ratepayers. The Commission denied that request in 2016, reasoning that the Aurora Solar project was approved as a cost-effective resource addition in the context of Xcel's integrated system as a whole and that Xcel had not shown that it would be just and reasonable for Minnesota ratepayers to subsidize North Dakota customers' solar energy consumption.[29]

B. Positions of the Parties

1. The Department

Echoing the reasons articulated in the Commission's 2016 order denying recovery of North Dakota PPA costs from Minnesota customers, the Department argued that it would be unjust and unreasonable to require Minnesotans to pay for Aurora Solar PPA costs that are rightfully attributable to South Dakota customers.

The Department asserted that the PPA was approved as a cost-effective addition to meet capacity needs in Xcel's system as a whole and, accordingly, fundamental cost-causation and allocation principles require that its costs be allocated across the entire system like any other shared system cost. The Department contended that Xcel provided no data to support a finding that the project is a reasonable way to meet the needs of only Minnesota ratepayers or that it would be just and reasonable for Minnesotans to subsidize this benefit for South Dakotans.

The Department disputed Xcel's argument that Minnesota customers should cover these costs because Minnesota policies favoring renewable and solar energy also factored into the Commission's selection of the Aurora Solar PPA; in the Department's view, any additional

Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel (February 5, 2015).

[29] *In the Matter of the Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of Cost Recovery of the Aurora Power Purchase Agreement*, Docket No. E-002/M-15-330, Order Denying Recovery of North Dakota Related Purchased-Power Costs at 4 (April 13, 2016).

benefit toward Minnesota renewable-energy goals does not negate the capacity benefits South Dakota customers receive from the project or the requirement that South Dakota customers pay for such benefits under fundamental cost-allocation principles.

Additionally, the Department argued that Xcel's request to recover PPA costs incurred from 2017–2021 should be denied because these are out-of-test-year costs for which the Company did not timely petition for deferred-accounting authorization and for which good cause has not been shown to authorize deferred accounting.

2. Xcel

Xcel argued that it is reasonable to recover these costs from Minnesota ratepayers because the Commission directed the Company to enter into the Aurora Solar PPA despite Xcel's concerns about the cost of the project. Xcel stated that, in approving the Aurora Solar PPA, the Commission referred to Minnesota policies favoring renewable energy and greenhouse-gas reduction which have no analog in South Dakota. Because South Dakota law does not recognize renewable-energy generation and the reduction of greenhouse-gas emissions from electricity generation as policy goals, Xcel characterized these features of the PPA as Minnesota-specific benefits for which Minnesota customers alone should pay.

Xcel sought to distinguish this case from the 2016 North Dakota decision, arguing that the 2016 Commission decision was predicated in part on an agreement in which Xcel agreed to waive its termination right and Aurora agreed to reimburse Xcel if neither the North Dakota nor the Minnesota commissions allowed recovery of the North Dakota costs. In contrast, the record contains no evidence that Xcel has an alternative means to recover the South Dakota costs if recovery is denied in this proceeding.

C. Recommendation of the Administrative Law Judge

Noting that the Commission's 2016 denial rested on a determination that the Aurora Solar PPA was cost effective for Xcel's system as a whole and that it would be unreasonable to require Minnesota customers to subsidize this benefit for customers in another state, the ALJ concluded that the same reasoning applies equally in this case.

The ALJ found that Xcel did not meet its burden to show that it would be just and reasonable for Minnesota ratepayers to pay for South Dakota customers' solar energy usage. Additionally, the ALJ found that Xcel did not establish that the SDPUC settlement—in which Xcel voluntarily agreed to absolve South Dakota ratepayers of these costs—is consistent with Minnesota ratepayers' interests or reflects a just and reasonable cross-jurisdictional allocation of system costs. The ALJ determined that Xcel's voluntary settlement of the issue of recovery in South Dakota provides an additional independent basis to conclude that Xcel has not met its burden to establish the reasonableness of recovering South Dakota costs from Minnesota ratepayers. Therefore, the ALJ recommended that the Commission deny Xcel's request to recover South Dakota Aurora Solar PPA costs both through base rates in 2022–2023 and through the Fuel-Clause Adjustment Rider starting in 2024, and adopt the corresponding revenue-requirement reductions of $2.857 million in 2022 and $2.689 million in 2023.

D. Commission Action

The Commission agrees with the ALJ that Xcel has not shown that it would be just and reasonable to require Minnesota customers to pay the requested portion of South Dakota Aurora Solar PPA costs. Therefore, the Commission will deny Xcel's request to recover South Dakota Aurora PPA costs through base rates in 2022–2023 and through the Fuel-Clause Adjustment Rider starting in 2024 and will adopt the corresponding revenue-requirement reductions of $2.857 million in 2022 and $2.689 million in 2023.

Xcel's request stands at odds with fundamental cost-causation and allocation principles. In its order approving the Aurora Solar PPA, the Commission found that the PPA was a reasonable and cost-effective investment for Xcel's distribution system as a whole, not limited to Minnesota. Although the order addressed beneficial environmental outcomes, the approval was also based on findings that the PPA would provide a cost-effective source of energy to support the reliability and adequacy of Xcel's power supply while alleviating transmission-line congestion and providing other benefits unrelated to Minnesota's renewable-energy and climate policies which benefit customers throughout the Company's multistate service area. The existence of environmental benefits recognized under Minnesota policy does not negate the other unrefuted benefits the PPA delivers to customers in other states within Xcel's integrated system.

Despite implying that Minnesota renewable-energy policies prompted the Commission to select the Aurora Solar PPA at a higher cost than the Company would have incurred in the absence of any renewable-energy preferences, Xcel has not demonstrated that the portion of South Dakota's costs it seeks to impose on Minnesotans is a reasonable approximation of any incremental cost attributable to Minnesota policies or of any incremental value that Minnesota customers purportedly receive from this PPA over an alternative as a result of Minnesota-specific policies.

Rather, the South Dakota cost that Xcel would impose on Minnesotans derives from the proxy price set in the Company's settlement agreement with SDPUC staff. The proxy price was not imposed against the Company's objection through an SDPUC decision or court order. To the contrary, in settling, Xcel voluntarily agreed to waive its right to recover from South Dakota customers their full jurisdictional share of Aurora Solar PPA costs. The record contains no persuasive evidence that the settlement, the settled proxy price, or the resulting balance that Xcel seeks to impose on Minnesota customers are consistent with Minnesota ratepayers' interests or reflect a just and reasonable cross-jurisdictional allocation of these system costs.

Because it would be neither just nor reasonable for Minnesota customers to pay the portion of South Dakota Aurora Solar PPA costs Xcel agreed not to recover from South Dakota customers under its settlement with SDPUC staff, the Commission will deny Xcel's request and require the Company to remove the corresponding amounts from its revenue requirement.

XIV. Luverne Wind2Battery Removal Costs

A. Introduction

The Luverne Wind2Battery System is a one-megawatt (MW) wind energy battery storage system that was installed in December 2009 and connected to a nearby 11-MW wind farm as one of the first utility-scale batteries installed in the United States. Xcel took on this project as an experimental pilot to assess the utilization of battery storage in conjunction with wind production. The project was decommissioned in 2019, years after the pilot study had been completed, when the battery was approaching the end of its useful life and its manufacturer informed Xcel that it would no longer manufacture replacement parts for the battery. Xcel explored options for future use of this asset but ultimately determined that the removal of the battery was the best course of action and now requests to recover its costs for removing the battery through a reserve reallocation.

When the battery was placed in service in 2009, Xcel proposed a net salvage value of 0% because it assumed the net cost of disposal would be approximately equal to the salvage value of materials recovered from the battery. Since then, Xcel has performed three comprehensive dismantling studies: in 2010, 2015, and 2020. Xcel did not update the battery's salvage value or provide supporting documentation for its removal costs following either its 2010 or its 2015 dismantling studies. As late as the 2015 study, Xcel maintained the same assumption that the disposal cost and the value from recycling the battery would offset each other. At that time, Xcel considered the cost of further investigating the net salvage value to be too large relative to the battery's value to be worth pursuing.

Xcel did not provide any updated estimates for Wind2Battery dismantling costs during the battery's service life. According to the Company, it first began investigating the removal cost once it learned that the battery was entering legacy status in 2018.

In its 2020 remaining lives and depreciation study, Xcel updated the net salvage value for the battery to –135.6%. Xcel sought to recover $5.6 million in decommissioning costs through a reserve allocation in its 2020 remaining lives docket, but at that time the Company cited only a manufacturer's representation and not a dismantling study in support of its estimation, and the Commission determined that the issue should be revisited in this rate case following additional record development.[30]

In this docket, Xcel filed a 2022 dismantling cost study which the Company maintains does not modify its previous $5.6 million reserve allocation request. The study estimated that the expected total for decommissioning the Wind2Battery asset is $2.14 million, with a worst-case upper estimate of $5.26 million. The higher estimate reflects the cost if damage or leakage occurs requiring special handling and an increase in recycling and other costs.

Xcel proposed to perform a reserve reallocation to recover the estimated costs of removal of the Luverne Wind2Battery project. The Company initially requested to shift $5.6 million of reserves from Other Production plants and apply it toward battery removal. However, after oral argument, Xcel agreed to reduce its reallocation request to no more than $2.14 million and agreed that it would not seek any additional reserve reallocations from assets in the Other Production account or seek recovery of any additional costs associated with Wind2Battery if this request is granted.

[30] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of its 2020 Annual Review of Remaining Lives and Five-Year Depreciation Study*, Docket No. E,G-002/M-19-723, Order Approving Petition in Part (September 2, 2021).

If the actual cost to dismantle, dispose of, and fully restore the site associated with the Wind2Battery system turns out lower than the reallocated amount, Xcel agreed to perform an inverse reallocation to return the unused reserves back to the groups they came from in a future proceeding.

B. Positions of the Parties

1. Opponents of Xcel's Proposal

The Department and the OAG opposed Xcel's proposed reserve reallocation or any recovery of costs for removal of the Wind2Battery asset, arguing that it would contravene standard depreciation practices and create intergenerational inequities.

Depreciation expense, including removal cost, is normally collected while the asset is in service so that any removal costs are collected from the same ratepayers that benefit from the asset. The Department and the OAG argued that Xcel's proposal would violate this standard practice and unjustly impose removal costs on customers that have not benefited from the battery.

The OAG and the Department argued that Xcel had the opportunity to recover estimated removal costs during the battery's useful life and failed to avail itself of that opportunity, and that it would be unjust to grant its untimely request now.

For these reasons, the Department and the OAG recommended that the Commission deny Xcel's reserve-reallocation request, disallow recovery of any Wind2Battery removal costs, and remove any depreciation expense for the Wind2Battery asset for 2022–2024.

Further, because the Wind2Battery depreciation expense for each year was not clearly identified in the record, the Department and the OAG recommended that the Commission require Xcel to make a compliance filing explaining the calculation of those depreciation-expense amounts and demonstrating that they have been removed from rates.

2. Xcel

In defense of its failure to recover removal costs during the battery's useful life, Xcel argued that its initial dismantling estimate of $0 was reasonable based on the information that was available at the time, including prevailing assumptions about the salvage value of components of the battery and discussions with its initial vendor. Further, Xcel contended that the experimental nature of the battery used in the project created challenges in estimating the disposal cost, excusing Xcel's delay in investigating the cost and requesting associated cost recovery.

Additionally, Xcel argued that its proposed reserve reallocation would not result in intergenerational inequities because the Wind2Battery pilot program generated significant research value, leading to the development of valuable information about the use of sodium sulfur batteries for renewable energy storage, which benefits current customers.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny Xcel's request to recover any Luverne Wind2Battery removal costs from ratepayers. The Company is obligated to provide five-year updates on salvage rates under Minn. R. 7825.0700 but failed to do so with respect to this project. The ALJ was not persuaded by Xcel's arguments that the novelty of the project made it infeasible to estimate removal and salvage costs earlier; to the contrary, the project's novelty and status as a pilot should have prompted Xcel to be more diligent about evaluating this aspect of the project and revisiting early assumptions during the project's useful life rather than forgoing a 2015 reassessment and relying on assumptions made when first placing the new, experimental technology into service until the battery entered legacy status. The ALJ found that Xcel had not provided an adequate justification for failing to act sooner to estimate and recover the costs.

The ALJ also found unpersuasive Xcel's argument that the pilot's research benefits justify recovering the removal costs from current ratepayers. The ALJ stated that this rationale is unsupported by typical ratemaking principles and generally accepted utility accounting practice, which strive to provide for recovery for depreciation of utility property while the property is used and useful in rendering service to the public. The ALJ added that the insights gained from the pilot project are distinct from the asset, have not been quantified, and do not justify ongoing recovery for the asset from ratepayers.

For these reasons, the ALJ recommended that the Commission disallow Xcel's requested reserve reallocation for the Luverne Wind2Battery removal project and adopt the Department's proposed adjustment to Xcel's revenue requirement corresponding with that decision.

Additionally, the ALJ recommended that the Commission adopt the OAG's recommendation to disallow the associated depreciation expense of $300,000 for the Minnesota jurisdiction in the 2022 test year and amounts to be identified by Xcel in 2023 and 2024.

Alternatively, if the Commission finds it reasonable to allow a reserve reallocation for these costs, the ALJ would recommend limiting the amount to $2.14 million and requiring Xcel to return any unused reallocated amounts to the groups they originated from if actual costs are lower than the amount reallocated. The ALJ found that $2.14 million—the expected total from Xcel's dismantling study—is a reasonable cost to dismantle the Wind2Battery system, but that the prudence of any cost above that total has not been demonstrated.

D. Commission Action

Respectfully, the Commission disagrees with the ALJ's recommendation to deny Xcel's proposed reserve reallocation for Wind2Battery removal costs.

Although the OAG and the Department raised important questions about whether Xcel should have taken further actions to estimate dismantling costs earlier and recover those costs during the battery's useful life, the Commission is persuaded by Xcel's argument that the novelty and experimental nature of the project presented barriers to obtaining that information earlier in the course of the battery's development and operation such that the Company's actions of relying on the limited information it knew at the time, including representations from the initial vendor, fell within the broad range of reasonable utility conduct under the circumstances.

Furthermore, although the Commission recognizes the concerns that this reserve reallocation is a departure from traditional practices, the Commission is persuaded that current customers will benefit from the valuable information about the use of sodium sulfur batteries for renewable energy storage developed through the Wind2Battery pilot and, therefore, granting a limited reserve allocation will not result in unreasonable intergenerational inequities. Based on the unique circumstances demonstrated in the record, the Commission finds that enforcement of depreciation rules in the way the Department and the OAG request in this case would impose an excessive burden on Xcel, and that approving a limited reserve reallocation for Wind2Battery dismantling would not adversely affect the public interest or conflict with legal standards.

The Commission concurs with the ALJ that $2.14 million is a reasonable estimate for the costs to dismantle the Wind2Battery system based on the record. Therefore, the Commission will approve a reserve reallocation of no more than $2.14 million for recovery of reasonable costs to dismantle, dispose of, and fully restore the site associated with the Wind2Battery system. If actual costs are lower than $2.14 million, Xcel will be required to perform an inverse reallocation to return the unused amounts back to the groups they came from in a future proceeding. As Xcel agreed during the Commission meeting, the Company shall not seek additional reserve allocations from assets in the Other Production plants account and shall not seek recovery of any additional costs associated with Wind2Battery in the future.

XV. Construction Work in Progress

A. Introduction

"Construction work in progress" (CWIP) and "allowance for funds used during construction" (AFUDC) are accounting devices used to allow utilities to recover the financing costs of capital projects while they are under construction, before the plant is placed into service. Capital costs incurred during construction are placed into rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant goes into service. Once the plant is in service, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.

The Commission is authorized to consider CWIP and AFUDC when determining a utility's rate base under Minn. Stat. § 216B.16, subds. 6 and 6a.

Xcel's rate-increase request includes a substantial amount of CWIP in rate base to reflect forecasted construction expenditures related to putting fixed assets into use, with a corresponding offset of AFUDC added to operating income.

B. Positions of the Parties

1. The Commercial Group

The Commercial Group recommended excluding CWIP from Xcel's rate base, arguing that including CWIP shifts onto ratepayers risks that should be assumed by utility investors.
The Commercial Group asserted that, if issues arise during construction that lead to substantial delay or non-completion of a project, ratepayers who have funded the construction through the inclusion of CWIP in rate base are forced to bear the loss; they do not receive the expected benefit in the form of completed plant, and they have no recourse to recover the value they contributed through rates. The Commercial Group argued that placing this risk of stranded costs

on ratepayers is unjust and unreasonable because ratepayers receive no compensation for the use of their funds.

Instead, the Commercial Group contended that a more just and reasonable approach would be to treat this risk of stranded costs as a cost of doing business to be borne by shareholders, who are compensated for such business risks through the return they receive on plant once it is in service. Alternatively, if Xcel is permitted to include CWIP in rate base, the Commercial Group would recommend that the Commission reduce Xcel's return on equity to reflect the corresponding transfer of risk from Xcel's shareholders to ratepayers.

2. Xcel

Xcel opposed the Commercial Group's recommendation, contending that the Commission has authorized the inclusion of CWIP in rate base for many years and that the Commercial Group has not offered a persuasive reason to depart from past practice in this case.

Further, Xcel argued that it is inappropriate to reduce its return on equity to reflect CWIP because the Company's proposed return already includes an offset for AFUDC. Xcel contended that the AFUDC offset ensures that no return is earned on the construction of assets before they have been placed in service, effectively negating the Commercial Group's concern that the return does not accurately reflect the risk impacts of CWIP.

Xcel also noted that the cost of short-term debt is included in the calculation of the allowed overall return on rate base, which further ensures that the inclusion of CWIP in rate base does not inappropriately place costs on customers or shift risks onto them. Xcel argued that removing CWIP from rate base without offsetting adjustments to AFUDC and the inclusion of short-term debt in calculating the Company's overall return would unreasonably upset this balance.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve Xcel's proposed inclusion of CWIP in rate base and not adopt the Commercial Group's proposal to adjust the Company's return on equity based on CWIP. Asserting that Minn. Stat. § 216B.16 requires the Commission to consider CWIP when determining rate base, the ALJ found that Xcel's inclusion of AFUDC and the cost of short-term debt in the calculation of the return on rate base avoids inappropriately placing costs on, or shifting risks to, ratepayers in connection with the inclusion of CWIP in rate base.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve Xcel's proposed inclusion of CWIP in rate base. Xcel supported its request with persuasive evidence and argument and demonstrated that its consideration of AFUDC and the cost of short-term debt in calculating the return on rate base avoids inappropriately placing costs on ratepayers in connection with CWIP.

XVI. Fault Location, Isolation, and Service Restoration

A. Introduction

Fault Location, Isolation, and Service Restoration (FLISR) is a form of distribution automation that involves deployment of automated switching devices that work to detect faults in feeder mainlines, isolate the faults, and restore power to unfaulted sections, thus decreasing the duration and number of customers affected by any individual outage.

Xcel proposed to add about $19 million in capital costs to its rate base and incur about $1 million in related O&M costs to install FLISR on 208 feeders in Minnesota between 2022 and 2024. Xcel asserted that this investment would improve reliability and lead to a two-thirds reduction in the number of customers who experience a sustained outage because of a fault.

B. FLISR Cost-Benefit Analysis

Xcel performed a cost-benefit analysis that sought to quantify the reliability benefits of deploying FLISR on 208 feeders compared to the cost of doing so. To calculate benefits, Xcel estimated the improvement in customer restoration times from the FLISR proposal in the form of reduced "customer minutes out." Xcel multiplied this estimate by the value of these outage minutes according to the Lawrence Berkeley National Lab Interruption Cost Estimate calculator, which involved a meta-analysis of customer value-of-service studies and a two-part regression model to estimate customer interruption costs per event by season, time of day, day of week, and geographical region for industrial, commercial, and residential customers.

Xcel also estimated the total net present value of FLISR costs through 2041, including asset costs, distribution communication, Advanced Distribution Management System integration and testing, and O&M costs corresponding to deployment and ongoing support and communications. Based on its cost-benefit analysis, Xcel estimated that the benefits of its proposed FLISR deployment will likely exceed the costs.

C. Positions of the Parties

1. FLISR Expense and Cost-Benefit Analysis

The Department argued that Xcel's cost-benefit analysis was reasonable because it relied on sound assumptions and methodologies. The Department agreed with Xcel's analysis that the proposed FLISR program is likely to produce net benefits and therefore recommended that the Commission approve recovery of the requested FLISR expense.

2. Allocation of FLISR Costs

Xcel proposed to recover FLISR costs based on the investments' functionalization as distribution assets, using general cost-causation principles through a class cost-of-service study.

The Department initially recommended reallocating FLISR costs so that residential customers pay only 3% and demand-class customers pay 97% to reflect the disparate class benefits. Using Berkeley Lab's Interruption Cost Estimate Calculator with inputs adjusted to match Xcel's Minnesota recorded system average interruption duration and frequency indices in 2020, the

Department estimated that about 97% of the financial benefits from the proposed FLISR deployment would flow to commercial and industrial customers while only 3% would flow to residential customers.

Before the Commission meeting, however, the Department withdrew its recommendation to adjust FLISR cost allocation in the current rate case due to the practical challenges of adjusting a class cost-of-service study at this late stage of the proceedings. However, beginning in the Company's next rate case, the Department recommended that Xcel be required to directly allocate FLISR costs to demand-class customers in its class cost-of-service study for the reasons discussed above.

The Clean Energy Organizations supported the Department's initial recommendation to allocate 97% of FLISR costs to demand customers as well as its alternative recommendation to require allocation of these costs to demand-class customers in Xcel's next rate case.

Xcel disputed the argument that FLISR costs should be allocated differently than other distribution assets, contending that FLISR aims to improve system reliability for all customer classes and to deliver those benefits as widely as possible. Further, Xcel argued that there are no established ratemaking methods to allocate these types of costs based on class benefits the way the Department proposes and that it would be impractical to attempt to do so because these costs involve many different types of distribution equipment.

The Commercial Group also opposed the proposal to reallocate FLISR costs and supported Xcel's preference to allocate these costs like other distribution-system costs.

3. Performance Metrics and Reporting

d. a. The Department

The Department recommended that Xcel's future recovery of FLISR expense be contingent on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR. The Department recommended that, prior to seeking future cost recovery for any incremental FLISR investments, Xcel should be required to propose a mechanism to base cost recovery for FLISR investments on reliability improvements.

The Department recommended that the Commission require Xcel to immediately begin tracking and reporting on the reliability performance of circuits equipped with FLISR improvements approved in this rate case, indicating in the Company's safety, reliability, and service-quality filings—beginning with the next such report, due April 2024—which circuits have been equipped with FLISR. The Department recommended that Xcel be allowed to modify the requirements on circuit-level performance reporting in its annual safety, reliability, and service quality reports to align with this recommendation.

Further, the Department recommended requiring Xcel to immediately begin reporting on the FLISR budget approved in this rate case along with a summary of FLISR's reliability results in its integrated distribution system plan (IDP), beginning with its next IDP due November 1, 2023. In its next rate case, or in any future proceeding where it seeks cost recovery for incremental FLISR investments, the Department recommended requiring Xcel to propose performance targets for System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), and, if applicable, any additional aspect of FLISR, based on the reliability performance data collected for circuits equipped with FLISR approved in the present rate case.

In the Company's next rate case or in any future proceeding seeking cost recovery for FLISR investments, the Department recommended requiring Xcel to propose a Performance Incentive Mechanism (PIM) for demonstrated benefits of circuits equipped with FLISR, using the PIM Design Process outlined in Docket No. E-002/CI-17-401. The Department recommended that Xcel's PIM proposal include, at minimum, the following elements:

(1) PIM structure.

(2) The dates when the PIM will take effect and terminate.

(3) Determination of the quantifiable and verifiable incentive values associated with performance in terms of SAIDI, SAIFI, and CAIDI above and below future associated targets, which may include a neutral zone around any particular target for acceptable performance.

(4) Specific mechanisms for effectuating a penalty or incentive on the Company; and

(5) An explanation of how stakeholders were engaged in the creation of PIMs.

The Clean Energy Organizations also supported adopting performance metrics and reporting requirements related to FLISR.

b. Xcel

Xcel largely agreed with proposals to require tracking and reporting on reliability performance for circuits equipped with FLISR, but it did not support conditioning cost recovery on performance metrics.

D. Recommendation of the Administrative Law Judge

The ALJ found Xcel's FLISR cost-benefit analysis reasonable and recommended that the Commission approve Xcel's proposed recovery of FLISR costs.

Further, finding that FLISR would provide reliability benefits for all customers, the ALJ recommended approving Xcel's proposal to allocate FLISR cost recovery based on the investments' functionalization as distribution assets. The ALJ was not persuaded by the Department's arguments for allocating 97% of FLISR costs to demand-class customers.

The ALJ found that it would be reasonable to modify Xcel's reporting requirements as recommended by the Department,[31] and that the additional reporting would not be unduly

[31] At the time the ALJ Report was prepared, the Department was recommending an initial, less-developed version of the reporting requirements described above. The initial recommendation was to require Xcel to track and report on reliability performance for circuits equipped with FLISR and compare these results with the average of reliability data from the previous eight-year period before FLISR was installed, including annual reporting on SAIDI, SAIFI, and CAIDI.

burdensome because it is largely an extension of Xcel's existing obligations. Moreover, the ALJ found that the additional information may help inform the Commission, stakeholders, and the Company of the efficacy of grid modernization spending going forward.

E. Commission Action

The Commission concurs with the ALJ that Xcel's FLISR cost-benefit analysis is reasonable and shows that the benefits of the proposed FLISR deployment will likely outweigh its costs. The Commission will therefore approve Xcel's request to recover 2022–2024 FLISR program costs. Xcel persuasively demonstrated that its proposed investments in FLISR are reasonable and will likely produce substantial benefits for customers sufficient to justify their costs.

The Commission will also approve Xcel's proposed allocation of FLISR costs, as recommended by the ALJ. Xcel persuasively demonstrated that FLISR will provide system benefits for all customers and that it is therefore reasonable to allocate its costs based on the investment's functionalization as distribution assets. On this record, the Commission is not persuaded by the Department's proposal to require Xcel to allocate FLISR costs to demand customers only in its class cost-of-service study in its next rate case.

The Commission finds reasonable and will adopt a modified version of the Department's proposal regarding performance metrics and reporting, as set forth in the ordering paragraphs below.

The principal substantive difference between the reporting requirements adopted by the Commission and those recommended by the Department is that the Commission will not require future FLISR cost recovery to be contingent on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR. Instead, the Commission finds that future FLISR cost recovery *may* be based on such showings. The Commission agrees with the Department that it is important to consider reliability benefits and other benefits when making decisions on future FLISR cost recovery; however, it is also important to preserve flexibility and avoid restricting the Commission's future decisions prematurely.

XVII. Asset Health and Reliability

A. Introduction

Asset health and reliability is a capital budget category within Xcel's distribution area that covers programs and projects that address the age and condition of distribution facilities. Projects in this category include replacement of underground cable, wood poles, overhead lines, and substation equipment that have reached the end of their lives as well as replacements due to damage. Xcel's proposed capital investments for asset health and reliability total $168.9 million in 2022, $180.8 million in 2023, and $205.0 million in 2024 on a Minnesota jurisdictional level.

B. Positions of the Parties

1. The Clean Energy Organizations

Noting that the proposed asset health and reliability budget has significantly increased from previous years, the Clean Energy Organizations recommended that Xcel be required to develop a cost-benefit analysis for investments in this category and cap any "discretionary" investments—i.e. those not specifically required by an order—at their expected level of benefits. The Clean Energy Organizations argued that much of Xcel's asset health and reliability spending is discretionary because the Company has discretion to decide when, where, and how much to spend in this category.

Alternatively, the Clean Energy Organizations recommended that the Commission require Xcel, in its next IDP, to propose and discuss ways for the IDP process to inform financial and cost-recovery issues in rate cases, including but not limited to (a) the feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget and (b) the decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP.

Just Solar supported the Clean Energy Organizations' alternative recommendation to require Xcel to explore these issues in its next IDP.

2. Xcel

Xcel opposed the Clean Energy Organizations' recommendations. Xcel argued that increased investment in this category compared to previous years is necessary due to the age and condition of key assets, including transformers that are already past their anticipated service lives.
The Company challenged the characterization of asset health and reliability investments as discretionary, asserting that this category of spending focuses on addressing assets that are aging or in poor condition which would place the system at greater risk of equipment failures and outages if not addressed. Although there is some flexibility with respect to the timing of these investments, such as determining when to replace end-of-life assets that have not yet failed, Xcel argued that it is inaccurate to characterize these investments as discretionary because they are necessary to fulfilling the Company's obligation to provide reliable service.

Moreover, Xcel contended that it would be unreasonable to make asset health and reliability investments contingent on a cost-benefit analysis because the reliability benefits of these types of investments are difficult to quantify but necessary to the provision of service. Further, Xcel provided testimony that requiring cost-benefit analyses for these kinds of investments would be impractical and costly, as this category is the distribution area's largest budget category and includes more than 100 subprograms and projects.

Within its asset health and reliability budget category, Xcel asserted that it uses a thorough budgeting process for each program that ensures the proper level of investments. This budgeting process accounts for the need to proactively replace end-of-life assets before they fail as well as forecasted replacements due to unanticipated failure or damage.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel met its burden to demonstrate that its asset health and reliability budgeting process and proposed budget are reasonable. The ALJ rejected the Clean Energy Organizations' recommendation to make many of these investments contingent on a cost-benefit analysis and cap spending at the expected level of quantifiable benefits, finding persuasive

Xcel's argument that these investments provide reliability benefits that are necessary to the provision of adequate service even though they are difficult to quantify.

The ALJ therefore recommended that the Commission approve Xcel's proposed asset health and reliability costs and not adopt the recommendation to require cost-benefit analyses for discretionary spending in this category.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve Xcel's proposed Minnesota jurisdictional distribution capital addition costs for asset health and reliability of $168.9 million for 2022, $180.8 million for 2023, and $205.0 million for 2024. The record contains substantial evidence supporting Xcel's asset health and reliability budgeting process and the reasonableness of the Company's proposed budget in this category for 2022–2024.

The Commission will not adopt the Clean Energy Organizations' recommendations to require a cost-benefit analysis and to cap recovery of discretionary spending in this category at the investment's expected level of benefits. Xcel persuasively argued that some asset health and reliability investments are necessary to maintain the distribution system at the level of reliability needed for the provision of adequate service to customers, and that the true value of these functions may not feasibly be quantified or captured in a traditional cost-benefit analysis.

However, the Commission acknowledges the Clean Energy Organizations' concerns about the size of this budget category and the degree to which it has increased since Xcel's last rate case. In light of these concerns, it is in the public interest to explore possible ways to achieve greater transparency and closer scrutiny of future distribution spending to ensure due consideration of ratepayer interests and other policy goals. Further, it is reasonable to direct this conversation to Xcel's next IDP docket, where it may be considered in the broader context of Xcel's integrated distribution system planning.

Accordingly, the Commission will adopt the Clean Energy Organizations' alternative recommendation to require Xcel, in its next IDP, to propose and discuss ways for the IDP process to inform financial and cost-recovery issues in rate cases, including the feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget and the decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases aligns with policy goals established through the IDP.

XVIII. Cable Replacement Program

A. Introduction

Xcel requested to recover capital additions of $32.7 million in 2022, $34.3 million in 2023, and $35.4 million in 2024 for its cable replacement program, which is within the asset health and reliability program discussed above.

The largest portion of the cable replacement program budget is for "reactive" cable replacement, i.e., replacing cable that either is damaged beyond repair or has failed more than once in a two-year period. If reactive replacements are lower than forecasted in a given year, Xcel uses the remainder of the program budget to perform "proactive" replacements of cable that has a history of poor reliability but does not meet the criteria for reactive replacement.

B. Positions of the Parties

1. Xcel

Xcel cited four reasons for the increase in its 2022–2024 cable-replacement budgets over previous years: (1) a rise in cable failures in 2019 and 2020, (2) inflationary increases in labor and material costs, (3) Xcel's decision to transition to conduit construction for mainline cable replacements beginning in 2022, and (4) Xcel's new proposals to sometimes replace mainline cables after their first rather than their second failure and replace entire half-loop segments of underground residential distribution cable after the first failure of a segment. While the first two factors driving the budget increase may be considered beyond Xcel's control, the latter factors relate to changes in Xcel's practices.

Xcel contended that, although it is more costly, using conduit construction as opposed to direct-burying mainline cable improves reliability by protecting cable from wildlife and the elements. With respect to its proposal to replace the entire half-loop of underground residential distribution cable after the first failure of a segment, Xcel argued that this proactive approach will prevent additional failures and outages. The Company provided testimony that additional failures on the same half-loop tend to occur in rapid succession after the first failure of a segment, as all cables in the half-loop are exposed to the same environmental and loading conditions.

Additionally, Xcel contended that replacing cable that has failed just once would allow the Company to avoid emergency replacements. Emergency replacements leave the system with less redundancy and switching options and can lead to lengthy outages if additional failures occur. Xcel maintained that it would only perform these proactive types of cable replacements if sufficient funding were available in a given year, which will depend on the number of other types of cable replacements performed each year.

Xcel argued that the requested funding is necessary for reliable service because cable failures are a main contributor to outages for customers who are served by underground facilities and account for approximately 65% of the "customer minutes out" on the Company's underground system from 2016–2020.

2. Just Solar Coalition

Just Solar recommended that the Commission deny Xcel's proposed cable-replacement budget until Xcel distinguishes the portion of the budget dedicated to reactive replacement from the proactive portion and justifies any proactive spending with a reliability-driven cost-benefit analysis that demonstrates that such proactive replacements are reasonable and cost effective. Just Solar recommended that the Commission require Xcel to identify the criteria used in its analysis—which should include equity and energy justice considerations—and demonstrate why such criteria result in just and reasonable investments.

Just Solar argued that Xcel has not met its burden to justify its proposal to engage in more proactive cable replacements or the associated funding increase. It asserted that, by combining the budget for proactive and reactive replacements, Xcel obscured the different analysis required to assess the benefits and reasonableness of these different types of replacements. Just Solar contended that it is important to evaluate the reasonableness and cost effectiveness of the cable replacement program specifically because it represents a large portion or Xcel's requested capital additions and, thus, is a significant contributor to the requested rate increase.

Additionally, Just Solar recommended that the Commission require Xcel to track and report its planned and actual spending on each category of replacements.

3. Xcel's Reply

Xcel opposed Just Solar's recommendation to condition cable-replacement funding on a cost-benefit analysis, arguing that it is difficult to quantify the reliability benefits of the proposals because multiple factors influence overall reliability performance. Further, given the increase in cable failures in recent years, Xcel argued that although proactive cable replacement may not produce immediate quantifiable reliability benefits, it could allow the Company to maintain its current reliability performance, which is necessary to fulfilling the Company's obligations to customers even though this value may not be adequately reflected in a cost-benefit analysis.

Xcel also opposed Just Solar's recommendation to designate rigid "reactive" and "proactive" components of the program budget, arguing that such a distinction would eliminate the flexibility the Company needs to address reactive replacement needs, which vary from year to year, while making efficient proactive use of any remaining funds.

C. Recommendation of the Administrative Law Judge

The ALJ found Xcel's proposed cable-replacement budgets reasonable and prudent and recommended that the Commission approve them. The ALJ also specifically found that Xcel's plans to replace mainline cable after one failure and to replace the entire half-loop of an underground residential distribution cable after the first failure of a segment as funding is available are reasonable and prudent plans based on substantial evidence in the record. The ALJ found that Xcel's proposals for the cable-replacement program are reasonable because they will provide reliability benefits and avoid emergency cable replacements that can lead to lengthy outages when additional failures occur.

The ALJ was not persuaded by Just Solar's arguments for denying any budget increase driven by proactive cable replacements unless they are shown to be cost effective. The ALJ found that it would be unreasonable to condition funding on a cost-benefit analysis for several reasons. The reliability benefits of Xcel's proposal are difficult to quantify and, moreover, are essential to fulfilling the Company's obligation to provide reliable service and therefore may be necessary and prudent even if their benefits that are quantifiable through a traditional cost-benefit analysis do not exceed their costs. Additionally, the ALJ found that it would be impractical or impossible to designate specific components of the budget for proactive and reactive cable replacements in advance because the amount of funding available for proactive replacements will fluctuate from year to year depending on the need for reactive replacements, which is affected by multiple factors that cannot be predicted with a high degree of accuracy.

However, the ALJ recommended adopting Just Solar's recommendation to require Xcel to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate-case filing. The ALJ found this requirement reasonable because the increased budget reflects a shift in the Company's approach, which regulators and the public should have an opportunity to review following implementation. The ALJ found that this tracking and reporting requirement would provide transparency and would not be unduly burdensome to the Company.

D. Commission Action

The Commission concurs with and will adopt the ALJ's recommendations on this issue. Xcel persuasively argued that allowing the Company flexibility to perform proactive replacements as funding allows after satisfying reactive-replacement needs in a given year is more reasonable than strictly committing specific portions of the budget to either reactive or proactive replacements in advance, before all relevant circumstances are known. Further, the Commission agrees with the ALJ that conditioning proactive cable-replacement spending on a cost-benefit analysis would not be effective in quantifying improvements that, whether proactive or reactive, substantially benefit customers by helping Xcel to maintain a reasonable level of reliability performance.

However, the Commission will adopt Just Solar's recommendation to require Xcel to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate-case filing as well as in its IDP budget filing. Because Xcel's proposal includes certain shifts in the way the Company intends to approach cable replacements, it is reasonable to collect and report on this data so that the Commission and stakeholders can review the effects of the shift following implementation.

XIX. Grid Reinforcement Program

A. Introduction

Xcel proposed $12.08 million in capital additions from 2022–2024 for a grid reinforcement program, which the Company stated would help prepare its distribution system to handle increased load from rising adoption of electric vehicles (EVs) and electrification of other sectors of the economy. The program would replace distribution-system infrastructure in areas where Xcel expects new load could eventually overload distribution equipment and cause outages.

Currently, Xcel handles distribution-equipment upgrades to accommodate increases in customer loads through two budget categories: (1) routine capacity reinforcements, which includes projects to support reliability by addressing known capacity constraints such as undersized transformers or conductors; and (2) new business, which includes projects to extend electric service to new customers or to support increased loads in response to customer requests.

The types of upgrades Xcel would make under the proposed grid reinforcement program are similar to routine capacity reinforcements and new business projects, including upgrades to service transformers, poles, primary conductors, and secondary conductors. The main difference between the existing programs and the proposed program is that, instead of targeting equipment or customers with an existing capacity need, the grid reinforcement program would focus on locations that Xcel determines are likely to experience an overload in the future because of anticipated EV load or other new electrification.

The Company stated that it would replace transformers and conductors under the program based on forecasted load growth, forecasted EV-adoption rates, and transformers that are at high risk of failure, targeting replacement of overhead residential service transformers rated 25 kVA or less that have the highest risk of failure according to Xcel's forecast.

B. Positions of the Parties

1. Parties Opposing the Grid Reinforcement Program

The OAG and Just Solar recommended that the Commission reject the grid reinforcement program, arguing that Xcel has not justified the substantial cost. They characterized the proposal to prospectively replace equipment that is not yet overloaded as being inherently speculative and based on unreasonable and unfounded assumptions about EV adoption and electrification. For example, the purported need for the project assumes that new EV-charging load will peak at the same time as the distribution-system peak; but the OAG and Just Solar argued that capacity constraints (and thus the need for costly infrastructure investments) related to EV load may be avoided entirely if the Company employs rate design, active managed charging, or other load-shifting techniques to shift EV charging away from times of peak demand.

Additionally, the OAG and Just Solar questioned why Xcel did not propose any reductions to its routine capacity reinforcements or new business budgets given that the need for those types of projects—which materially overlap with grid reinforcement projects—should decrease if the grid reinforcement program is approved. The OAG argued that adding the requested grid reinforcement program budget on top of Xcel's other distribution budgets would create a significant risk of unreasonable double recovery.

Just Solar contended that Xcel should be able to proactively plan for increased EV adoption and electrification using its existing new business and routine capacity reinforcement programs, without needing customers to pay for a new, overlapping $12.08 million program.

2. Xcel

Disputing arguments that the proposed grid reinforcement program is duplicative of other existing programs, Xcel contended that the grid reinforcement program is narrowly designed to proactively replace undersized overhead residential service-level transformers for a specific purpose; its routine capacity reinforcement program, in contrast, is a broad program to reactively address all smaller capacity issues for all customers throughout the system.

While acknowledging that the grid reinforcement program may lead to a reduction in reactive routine capacity reinforcement projects in the future, Xcel argued that the program will not result in an immediate reduction in routine capacity projects because this program would cover only 2% of the total residential service transformers in Minnesota.

Xcel emphasized that proactive replacement of residential service-level transformers that are near their capacity limits will benefit customers by avoiding both customer outages and costlier reactive replacements.

Xcel disputed the argument that the issues the program aims to solve can be entirely avoided through rate design and load-shifting programs, noting that customers participating in the Company's EV programs are not the only cause of increased load and that customers switching from gas to electric appliances or heat sources could also lead to a transformer overload. Additionally, Xcel argued that, although EVs can be programmed to charge during off-peak periods, scheduled off-peak EV charging could lead to new EV-related peaks, thus merely shifting rather than avoiding the overloading concerns. Xcel added that some customers cannot or will not modify their EV-charging behaviors in response to price signals.

Xcel argued that the benefits of the grid reinforcement program justify the reasonableness and prudence of the proposed investment.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission exclude the grid reinforcement program costs from Xcel's revenue requirement. The ALJ found persuasive the arguments of Just Solar and the OAG that Xcel has several existing means of avoiding transformer-related problems associated with EV and other electric load growth, including the Company's existing programs for new business and routine capacity reinforcement as well as EV programs that could facilitate strategic load shifting.

The ALJ found that the concern Xcel intends to address is speculative and depends on the confluence of multiple contingencies—a sufficient concentration or breadth of EV adoption during the MYRP, unavoidable synchronization of EV-charging loads, and inelastic EV-charging demand. The ALJ found that the record does not show that this alignment of events is more likely than not to justify the proposed revenue requirement increase and does not establish the reliability of the forecasts and analysis underlying Xcel's request for this purpose.

D. Commission Action

The Commission will adopt the ALJ's recommendation to reject Xcel's distribution capital addition costs for the grid reinforcement program for 2022–2024. Although it is important to ensure that the distribution system is prepared to handle increased load from increased EV adoption and other electrification, the Company has not established that its proposed $12.08 million grid reinforcement program is reasonable.

As the OAG noted, Xcel has not shown that it duly considered whether managed EV charging or other load-shifting programs could be used to avoid or reduce the need for costly grid upgrades associated with transportation electrification. Nor does Xcel's proposal provide sufficient transparency or detail regarding where the grid reinforcement projects would be done or whether any costs of this program are duplicative of costs accounted for in the Company's routine capacity reinforcements and new business expense categories, which appear to materially overlap with grid reinforcement projects. Based on this record, the Commission will reject Xcel's grid reinforcement program as proposed and require its removal from the Company's revenue requirement for ratemaking purposes.

XX. Distributed Intelligence Capital Additions and Operations and Maintenance Costs

A. Introduction

Distributed intelligence (DI) generally refers to the computer processing and analytics capabilities of localized distribution grid devices and platforms. DI involves relatively new technology that enables the Company to extract precise, instantaneous insights that it can use for grid operations or to communicate real-time usage data directly to customers to help them make decisions about energy usage.

Xcel proposed to procure DI software and computer hardware that would allow the Company to leverage advanced meter data to offer new services to customers and help the utility to manage its distribution system more efficiently. Xcel identified the following initial uses for its proposed DI program: energy analysis, home area network connectivity, EV detection, outage and voltage fluctuation detection, and a connectivity pilot.

During 2022 and 2023, Xcel plans to develop and deploy three customer-facing DI uses: (1) home area network connectivity, which would allow customers to connect to the meter on their premises using Wi-Fi and provide customers real-time access to energy usage data; (2) energy analysis, which would provide customers information on the energy usage of specific appliances; and (3) EV detection, which would detect a customer's EV charging, quantify the EV-specific energy-consumption profile, and provide a channel for Xcel to introduce customers to EV programs and rates that best suit their needs.

The Company plans for additional deployment of grid-facing DI in 2024, including broader deployment of the grid-facing pilots introduced in 2022 and 2023 and potentially including development of other applications that are not currently available.

Xcel's proposed DI budget includes $33 million in capital additions beginning in 2024 and $3.6 million in O&M expenses from 2022–2024. This budget includes costs to implement the foundational software architecture necessary to enable DI capabilities and to develop and deploy initial customer- and grid-facing DI use cases. In rebuttal testimony, Xcel proposed a revised budget that includes electric-only allocators for DI costs and a new shared-asset accounting structure.

B. Distributed Intelligence Cost-Benefit Analysis

Xcel provided a cost-benefit analysis for the energy analysis use which, according to the Company, was conservative in that it included all costs during the rate-plan years but only captured the portion of the benefits that could be quantified at this time with sufficient certainty, rather than all of the project's likely benefits. Xcel's updated cost-benefit analysis showed an expected benefit-to-cost ratio of approximately 1.44 under the Company's base scenario. Xcel asserted that there is 95% certainty that the benefit-to-cost ratio would be greater than 0.98, with a maximum ratio of 2.33.

Xcel asserted that the primary benefit of DI is the potential to provide information to customers that allows them to change their behavior in ways that promote energy efficiency and demand response, save on energy bills, and reduce carbon emissions. Additionally, Xcel stated that DI analytics will extend the Company's advanced capabilities for the distribution grid to allow more precise monitoring and control at the edge of the grid, leading to greater reliability and lower costs for managing the system.

C. Positions of the Parties

1. The Clean Energy Organizations

The Clean Energy Organizations requested that Xcel agree to implement its DI program consistent with the terms of a settlement agreement that the Company's affiliate in Colorado entered into for implementation of a similar program. The settlement terms of interest to the Clean Energy Organizations addressed Home Area Network deployment and issues of customer and third-party access to data. In its reply brief, Xcel stated that it planned to implement its DI program in Minnesota in a way that is generally consistent with the Colorado terms.

With this clarification, the Clean Energy Organizations supported Xcel's requested DI recovery, asserting that it could help customers better understand and reduce their energy usage and noting that the Company had significantly reduced the cost of the program from its initial proposal in its IDP docket.

2. The Department

The Department argued that Xcel's DI cost-benefit analysis was not reliable, citing concerns with the benefits measure used and with several assumptions underlying the model.

First, Xcel used estimated customer bill savings for participating customers to quantify DI benefits. The Department argued that, because a bill-savings-based analysis relies on prices derived from historical costs that cannot be avoided by the utility investment, quantifying benefits based on customer bill savings violated the principle that cost-benefit analyses should be forward-looking, long-term, and incremental to what would have occurred absent the investment.

Second, the Department argued that because customer bill savings would accrue only to actively participating customers, Xcel's analysis likely presents a high-end limit on potential benefits and does not adequately account for the risk that participating customers who save money may do so at the expense of non-participating customers. To produce methodologically reliable results rather than a best-case scenario, and to reflect the program's effects on all customers, the Department argued that Xcel should have evaluated program benefits by estimating the avoided utility costs of its DI proposal. The Department asserted that avoided utility costs are the standard measure of benefits for these types of analyses.

Further, the Department argued that Xcel's model was skewed by unreasonable assumptions about participation levels. Xcel based its participation-rate assumptions on its website's "My Account" login data, but the primary reasons customers log into those accounts are to view and pay bills; accordingly, the Department contended that this data is not a reasonable proxy to estimate how many customers would actively participate in DI programs to engage in energy-efficiency and demand-management best practices.

The Department challenged Xcel's use of general market research for digital products to estimate the percentage of enrolled customers leaving the program annually (referred to as "churn rate") and further contended that Xcel's selection of the highest churn rate was self-serving because the benefit-to-cost ratio improves as annual churn increases under Xcel's model.

The Department also argued that there was insufficient support for Xcel's 80% customer-interest value, which the Company derived from a single survey question asking how "interested" respondents would be in downloading "an app to allow you to understand your energy usage." The Department argued that the generalized interest gauged by the survey question is not a reasonable proxy for active participation that would yield benefits.

Further, the Department questioned Xcel's assumptions about advanced meter deployment. Acknowledging that inflation and supply-chain issues have affected meter availability, Xcel reduced its 2022 estimate from 250,000 to 90,000 meters; however, the Company maintained its estimate of 670,000 meters in 2023. The Department argued that Xcel has not explained the significant increase in expected advanced meter deployment from 2022 to 2023 and contended that the high 2023 estimate inflates expected benefits relative to cost under Xcel's model.

The Department also expressed concern with the fact that Xcel's analysis produced a range of potential benefit-to-cost ratios from 0.98 to 2.33, arguing that this broad range of results reflects the limitations of Xcel's benefit-estimation methods and the significant risk associated with the proposal. The Department recommended that the Commission deny Xcel's request to impose the substantial cost of the proposed DI program on ratepayers at a significant risk that its benefits will fall below, or only barely exceed, its costs.

Finally, the Department opposed Xcel's proposal to change its accounting structure from treating DI as a shared asset owned on an enterprise-wide basis to an asset owned by Northern States Power–Minnesota (NSPM), which would add $37.8 million in capital to its 2024 plan-year rate base, approximately $14.3 million above the Company's original recommendation. The Department argued that this revised accounting structure would unreasonably shift business risk from shareholders to NSPM customers because Xcel's claim that other jurisdictions will contribute to the cost in the form of licensing fees in the near future relies on assumptions that Xcel's other jurisdictions will timely adopt DI programs.

3. The OAG

The OAG shared the Department's concerns and recommended that the Commission reject Xcel's proposed DI costs. However, the OAG recommended that the Company be allowed to seek approval of the program in a future proceeding with a more robust record.

Alternatively, if the Commission grants recovery of DI expenses, the OAG would recommend requiring Xcel to account for the DI program as an enterprise-wide asset as initially proposed by the Company. On a Minnesota-jurisdictional basis, this accounting structure would result in the removal of $3.1 million from rate base and $303,000 in O&M expenses in the 2022 test year; $12.1 million from rate base and $1,528,000 in O&M expense in 2023; and $24.6 million from rate base and $1.7 million in O&M expense in 2024.

The OAG argued that Xcel failed to support the revised DI accounting structure with adequate explanation and enough detail to allow parties to evaluate it. Further, the OAG argued that the costs for the DI asset do not reflect any credits from other operating companies for their use of the asset and that approving this structure would result in Minnesota ratepayers paying more than their fair share of DI costs in 2025 and beyond. Additionally, the OAG asserted that Xcel did not explain why the accounting changes should be reflected in the current rate case because (1) the DI asset would not be in service until the final month of 2024 and (2) Xcel claimed that the allocator update would not have a material impact on the overall DI budget allocated to NSPM through 2028.

The OAG argued that Xcel's late introduction of its revised accounting structure in rebuttal testimony heightened the need for the Company to provide detailed cost information to support the changes, which Xcel did not fulfill, and hindered other parties' ability to vet the proposal.

4. Xcel

Xcel argued that avoided cost is not the only potential measure of benefits and that it selected customer bill savings as the most indicative measure of the magnitude of expected DI impact based on the information currently available. In response to arguments that the cost-benefit analysis is not supported by enough data, Xcel contended that it is impossible to develop additional data about the benefits of DI without first deploying DI, particularly at this nascent stage in the technology's development.

Although its cost-benefit analysis is limited to the development of foundational DI capabilities and deployment of the initial customer- and grid-facing use cases proposed to be in service in late 2024, Xcel characterized its DI proposal as a necessary investment in the formative infrastructure for DI development that will unlock additional benefits in the future.
In defense of its participation-rate assumptions, Xcel asserted that it used additional data beyond the My Account login statistics and incorporated a sensitivity analysis including a range of assumptions and probabilities of different outcomes.

Xcel contended that the record contains sufficient evidence of DI benefits to support approving the requested cost recovery at this time even though some benefits cannot yet be quantified. Xcel stated that its cost-benefit analysis provides one point of reference to show that DI benefits will outweigh the costs of the foundational DI investments proposed.

To support its revised accounting structure, Xcel asserted that the asset should be owned by NSPM because DI applications will be available only in Minnesota initially, but that NSPM will receive offsetting O&M credits from other operating companies beginning in 2025 as regulatory approval is received and as customers begin benefitting from the asset in other jurisdictions. Xcel contended that this accounting structure will facilitate balanced allocation of costs to Xcel Energy's operating companies and better aligns with current information about when customers will benefit from DI in each jurisdiction.

Xcel opposed the OAG's suggestion to seek recovery of DI costs in a future proceeding, arguing that it is reasonable to approve the Company's request in the current rate case because customers will begin to receive benefits from DI in 2023 as advanced meters are deployed.

D. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny cost recovery for Xcel's DI proposal, but without prejudice to any request in a future proceeding. The ALJ found that the Department identified significant shortcomings with Xcel's cost-benefit analysis and that, because the Company's analysis only narrowly found a net benefit, there are genuine doubts about the methodology of the analysis and the reliability of its conclusions sufficient to conclude that Xcel did not meet its burden to show that the costs are reasonable.

Alternatively, if the Commission allows Xcel to recover distributed intelligence costs, then the ALJ would recommend adopting the OAG's alternative proposal to apply the accounting structure Xcel proposed in its supplemental direct testimony in lieu of the Company's revised accounting structure. The ALJ agreed with the OAG and the Department that Xcel's revised proposed accounting structure for these costs raises concerns about increased risk and uncertain benefits to Minnesota ratepayers, and that the introduction of this revised accounting proposal late in the proceedings deprived intervenors of the opportunity to develop a full record and analysis of that proposal.

E. Commission Action

The Commission will reject Xcel's proposal to include DI costs in rates. The Commission concurs with the ALJ's finding that Xcel has not met its burden to show that its proposed DI costs are just and reasonable. The Department raised important concerns about the assumptions and methodology underlying Xcel's cost-benefit analysis, and Xcel has not satisfactorily resolved those concerns. Although Xcel has identified potential uses of DI to help customers understand and control their energy usage and help the Company manage its distribution system more efficiently, the Commission is not persuaded that approval of Xcel's proposed DI program is justified based on the current record.

However, in recognition of the potential benefits suggested in the record, the Commission will direct Xcel to re-file its DI proposal in its next IDP. The Commission agrees with the OAG and the ALJ that there may be merit in allowing Xcel another opportunity to support its proposal with a more fully developed record that addresses the concerns discussed herein. Additionally, as Xcel agreed, the proposal to be filed in the next IDP shall be consistent with the settlement entered into by the Company's Colorado affiliate relating to a similar program.

XXI. Production Tax Credits

A. Introduction

Production tax credits (PTCs) are federal tax credits earned from the generation of electricity using qualified renewable energy resources. PTCs affect Xcel's revenue requirement by reducing income-tax expense and increasing operating income.

Because PTCs vary from year to year, Xcel proposed to create a PTC tracker account in its Renewable Energy Resources (RES) rider to annually refund or surcharge customers for the difference between actual PTCs received and the baseline set in the rate case.

Xcel initially forecasted that it would generate PTCs totaling $190.169 million for 2022, $192.916 million for 2023, and $193.385 million for 2024, and the Company requested to use those values as the baselines for PTC recovery during the MYRP.

In August 2022, the Inflation Reduction Act expanded the renewable generation facilities eligible for PTCs, increased the eligible percentage of PTCs for existing renewable facilities, and increased the megawatt-hour (MWh) rate for new and repowered renewable facilities. These changes significantly affected the amount of PTCs Xcel could expect to receive during the term of the MYRP.

Xcel provided an updated PTC forecast incorporating the Inflation Reduction Act changes as well as an updated wind generation forecast reflecting the most recent information about expected wind energy production. The updated PTC forecast is $217.753 million for 2022, $192.204 million for 2023, and $194.738 million for 2024.

No party opposed using the RES rider to true-up PTCs. However, parties disagreed on the appropriate baseline level for PTC recovery.

B. Positions of the Parties

1. The Department

The Department recommended using Xcel's updated PTC forecast as the baseline, arguing that using the most current estimate available will promote rate stability by protecting ratepayers from substantial surcharges or refunds when the amount is trued up.

The Department asserted the availability of a true-up mechanism does not eliminate the potential harm to ratepayers from overestimating the baseline because significant time will pass between any baseline overpayment and its corresponding true-up refund, during which time customers will be deprived of the use of the overpaid sums. Contrary to Xcel's claim that the differences of $1.288 million in 2023 and $1.353 million in 2024 are too small to warrant a baseline adjustment, the Department asserted that this amount of ratepayers' money is not negligible from each ratepayer's perspective and that Xcel has not shown that it is reasonable to collect those excess amounts in rates, even if they will be returned through future true-ups.

In response to Xcel's argument that the baseline should not be updated until the IRS provides further guidance on the implementation of the Inflation Reduction Act, the Department argued that any details that might change from the current understanding of PTC calculation under the Act based on future IRS guidance will not be so significant as to render the original forecast—which assumes the Inflation Reduction Act does not exist—a more accurate alternative than the updated forecast which reflects the most current information available.

2. Xcel

Xcel maintained its request to continue using its original PTC forecast, which does not reflect the Inflation Reduction Act or the Company's updated wind generation forecast. Xcel argued that it should not update the PTC forecast because the Company is awaiting further guidance from the IRS on Inflation Reduction Act implementation. Although the updated forecast reflects Xcel's current understanding of the impact of the Inflation Reduction Act on PTC calculation, the Company contended that the baseline should not be updated until final guidance is available because such guidance could cause PTC-calculation details to change.

Additionally, Xcel stated that its 2022 RES rider true-up has already been approved and its implementation has begun, so if the amounts included in base rates do not align with the assumptions made in the RES rider filing, then the amount in the RES rider would require an additional offsetting adjustment to avoid over- or under-recovery. Xcel argued that this approach would be needlessly complex, require additional administrative burden, and create risks of confusion and error. Given this procedural posture, Xcel argued that it could update PTC values more quickly directly through the RES rider, and thus refund customers sooner, if PTC adjustments are handled directly through the RES rider rather than through base rates.

While acknowledging that setting a reasonably accurate baseline is important to send appropriate price signals and to provide rate stability by minimizing the extent of future surcharges or refunds, Xcel disputed the contention that maintaining the initial forecast as the baseline would result in dramatic rate changes when the true-up occurs. Xcel asserted that the difference between the initial and updated PTC forecast for each year is under $1.4 million, which is relatively small in the overall context of the rate case.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Department's recommendation to update the PTC baselines reflects the best information available and is more reasonable than Xcel's proposal to rely on its initial forecast. The ALJ found that Xcel did not provide sufficient arguments to outweigh the ratepayer benefits of setting the baseline using the most up-to-date forecast available in the record. The ALJ therefore recommended that the Commission adopt the Department's recommended PTC baseline update, with corresponding reductions to the revenue requirement in the following amounts: $27,584,000 in 2022, $1,288,000 in 2023, $1,353,000 in 2024.

D. Commission Action

The Commission will adopt the ALJ's recommendation to update the PTC baseline amounts to reflect Xcel's updated PTC forecast, reducing the Company's 2022–2024 revenue requirements by $27,584,000, $1,288,000, and $1,353,000, respectively.

No party disputed the importance of setting a reasonably accurate baseline to reduce the likelihood of substantial surcharges or refunds when the baseline amount is trued up and to send appropriate price signals. Using the most current forecast information available can often be expected to yield the most accurate baseline cost estimates. In this case, the updated PTC forecast reflects significant changes resulting from the Inflation Reduction Act and Xcel's updated wind-generation forecast, neither of which was available when Xcel produced its initial forecast. The Commission finds it is reasonable to base the PTC baseline values on the updated PTC forecast because this approach is likely to produce more accurate results than the initial forecast developed based on out-of-date information.

Xcel did not provide persuasive reasons why it would be better to set the baseline based on outdated information. Although forthcoming IRS guidance could potentially vary some PTC-calculation details, the Commission agrees with the Department that it is exceedingly unlikely that any such changes would be so great as to render Xcel's original PTC forecast—which does not account for the Inflation Reduction Act at all—more accurate than the updated forecast. Additionally, the Commission is not persuaded that Xcel's concerns about administrative burden or potential confusion due to straying from the assumptions underlying the 2022 RES rider true-up filing outweigh the interests in aligning the base-rate baseline with current forecast information.

Finally, Xcel's claim that the likely over-recovery of up to $1.4 million per year based on the initial PTC forecast is so small as to be negligible, and therefore does not warrant a baseline update, is not persuasive.

XXII. Load Flexibility Program Costs

A. Introduction

In Docket No. E-002/M-21-101 (the Load-Flexibility Docket),[32] Xcel requested approval of deferred accounting for costs related to load-flexibility pilot programs. In the Load-Flexibility Docket, which was underway when Xcel filed this rate case, Xcel requested authorization to track all 2021–2023 costs of its load-flexibility pilots for possible future recovery. Xcel divided its estimated load-flexibility-pilot expenses into the following categories: bill credits, customer services (equipment cost), program administration (including labor), advertising and promotions, measurement and verification (evaluations), and product development and research.

In the Load-Flexibility Docket, the Department recommended that the Commission deny deferred accounting for all of the pilot expense categories except two—bill credits and customer services—arguing that the remaining categories appeared to be labor costs already included in base rates. In a March 2022 order, the Commission approved some of the proposed load-flexibility pilots and authorized deferred accounting for bill credits and customer services costs.[33] Although the deferral authorization was specific to the cost categories recommended by the Department, the Commission did not make a determination as to the veracity of the Department's claim that the other cost categories were labor costs already included in base rates.

Xcel subsequently updated its cost of service to include the categories of load-flexibility-pilot costs that were not approved for deferred accounting in the Load-Flexibility Docket, totaling $870,000 in 2023 and $1.1 million in 2024 for the Minnesota jurisdiction.

B. Positions of the Parties

1. The OAG

The OAG opposed Xcel's request to recover load-flexibility program costs. It argued that the Commission's denial of deferred accounting for these expense categories in the Load-Flexibility

[32] *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, Docket No. E-002/M-21-101.

[33] Load-Flexibility Docket, Order Approving Modified Load-Flexibility Pilots and Demonstration Projects, Authorizing Deferred Accounting, and Taking Other Action at 25, 30 (March 15, 2022).

Docket was based on an implicit finding that they are labor costs already included in base rates, as the Department had argued.

The OAG contended that Xcel offered only a conclusory assertion that these costs are incremental to the labor costs already included in the Company's initial filing and did not provide sufficiently detailed evidence to verify the costs or the claim that they are incremental.

2. Xcel

An Xcel witness testified that the load-flexibility costs requested were not included in the initially filed cost of service; the Company had specifically removed these costs from the initial rate case filing to avoid double recovery because, at the time, it was seeking authority in the Load Flexibility Docket to track them separately and request deferred recovery.

In response to the timeliness argument, Xcel stated that it transferred the costs from the Load-Flexibility Docket to the rate case as soon as practicable following the partial denial of deferred accounting in the former docket, which is the earliest time the Company knew it would need to include the costs in this rate case because it would not be allowed to request deferred recovery in a future proceeding.

Xcel contended that denying recovery in this proceeding would leave the Company with no avenue to recover these costs, which would be unreasonable because the Commission approved the associated programs as reasonable and in the public interest in the Load-Flexibility Docket.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve rate recovery of Xcel's load-flexibility pilot costs as identified in the Company's rebuttal testimony, finding that Xcel established by a preponderance of the evidence that the requested recovery is reasonable.

The ALJ found that no party had identified any load-flexibility program cost shown to duplicate an expense already included in the Company's initial request. Because the Commission approved deferred accounting for portions of the costs of the load-flexibility programs upon a finding that the programs would serve important ratepayer and policy interests, and because Xcel's testimony that the additional costs are incremental has not been substantively rebutted, the ALJ found it reasonable to include the costs in rate base.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve rate recovery of the load-flexibility costs identified in Xcel's rebuttal testimony.

Contrary to the OAG's assertion, the Commission's March 2022 order in the Load-Flexibility Docket did not entail a finding that these expense categories are labor costs already included in base rates. Rather, after noting that deferred accounting is an exception to the uniform system of accounting under Minn. R. 7825.0300, subp. 4, and discussing concerns about deferred accounting generally being used to track only increases and not decreases in costs outside of a rate case—which could lead to inequities for ratepayers if used inappropriately—the

Commission did not find good cause for an exception to allow *deferral* of these costs. But the order did not preclude traditional recovery within a rate case corresponding to the test years in which the costs are incurred, as Xcel requests now, nor did it determine that these expenses are duplicative of costs already in base rates. Nothing in the Load-Flexibility Docket forecloses Xcel's request to recover load-flexibility-program costs not approved for deferred accounting.

The record persuasively demonstrates that Xcel specifically excluded the claimed costs from the Company's initial cost-of-service estimate in this rate case because, until the Commission denied its request in the March 2022 order, the Company was intending to seek deferred recovery of these costs instead of traditional rate recovery. No party effectively rebutted Xcel's evidence to show that these costs are duplicative of costs included elsewhere in the cost-of-service estimate or otherwise should not be added to rates. The Commission therefore finds that the load-flexibility costs Xcel requested in rebuttal testimony are incremental and can reasonably be added to Xcel's cost of service for recovery through base rates.

For these reasons, in addition to reasons articulated in the March 2022 order to approve the load-flexibility programs based on findings that they will serve important ratepayer and policy interests, the Commission finds that Xcel has met its burden to demonstrate the reasonableness of its requested recovery of load-flexibility-program costs.

Accordingly, the Commission will approve Xcel's request to recover load-flexibility-program costs totaling $870,000 in 2023 and $1.1 million in 2024 for the Minnesota electric jurisdiction.

XXIII. Integrated Volt-Var Optimization

A. Introduction

Xcel's initial revenue request included capital additions for integrated volt-var optimization (IVVO), an application that optimizes voltage as power travels from substations to customers. However, after it prepared the budget included in its rate-case filing, Xcel changed its plans and decided not to pursue IVVO during the term of the MYRP.

The parties agreed that Xcel should remove $0.2 million from 2023 and $1.8 million from the 2024 to reflect IVVO-related assets that were not used and useful during those years due to Xcel's termination of its IVVO plans. The ALJ recommended that the Commission adopt these adjustment amounts.

Following oral arguments, Xcel clarified that it has no plan to resume implementing IVVO at any time, including after the rate-plan years. When asked to explain its reason for abandoning its IVVO plans, Xcel stated that the Commission's decision not to certify the Company's proposed IVVO project in the 2020 IDP order led the Company to conclude that the Commission was not comfortable with the project moving forward.[34]

[34] *See In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects, at 15 (July 23, 2020) (2020 IDP order).

B. Commission Action

With respect to the $0.2 million and $1.8 million IVVO-related adjustments agreed upon by the parties and recommended by the ALJ, the Commission finds the adjustments reasonable and supported by the record and will therefore adopt them.

However, the Commission is concerned with Xcel's stated reasoning for terminating its IVVO efforts. In the 2020 IDP order, the Commission expressed general support for the goals of IVVO but was not persuaded that there had been enough record development or analysis to certify the specific proposal for purposes of rider recovery at that time. The Commission expressly noted that its decision not to certify at that time would not prevent Xcel from continuing its work on IVVO or seeking cost recovery through traditional means.

The record suggests that, rather than pursuing further development of its IVVO proposal and analysis of the project's potential to serve the important goals identified in the IDP docket, as the 2020 IDP order anticipated, Xcel simply scrapped the pursuit based on its incorrect assumption that the Commission's decision implied a negative judgment about the merits of the project.
To ensure that the Company does not unduly abandon IVVO and all of its potential benefits based solely on a misunderstanding of the 2020 IDP order, the Commission will require Xcel, in its next IDP, to include an assessment and explanation of whether IVVO is in the public interest.

XXIV. Insurance Premium Expenses

A. Introduction

Xcel estimated its insurance-premium expense for the Minnesota electric jurisdiction as $20.7 million in 2022, $22.4 million in 2023, and $25.2 million in 2024, net of budgeted distributions from mutual insurance and captive insurance providers.

When estimating insurance costs, Xcel consults with insurance brokers on general trends in insurance markets to try to predict if prices will be trending up, down, or flat. Xcel then estimates its likely exposure using metrics the Company evaluates annually, including the number of employees, miles of pipes and wires, and changes to the value of insurable assets. To set test-year insurance budgets, Xcel starts with the premiums it paid in the two preceding years and adjusts those amounts to account for the identified insurance-market trends and company exposure metrics. Xcel's insurance budgeting process also accounts for expected distributions from mutual insurance pools and captive insurers as credits against its estimated premiums.

B. Positions of the Parties

1. The Department

Noting that the insurance expenses Xcel estimated for 2022–2024 are significantly higher than the actual insurance expenses the Company incurred in 2021, and that proposed year-over-year percentage increases are significant compared to actual increases in Xcel's insurance expenses each year from 2017–2021, the Department argued that Xcel failed to show that its proposed insurance expenses are reasonable. In particular, the Department objected to the exceptionally large percentage increase between the 2021 actual insurance expense and the 2022 forecasted amount.

Although Xcel stated that the Company sought input from insurance brokers, the Department criticized the Company's decision not to offer any evidence from insurance brokers themselves directly into the record. The Department questioned persuasive value of Xcel's secondhand summaries of information purportedly obtained from insurance brokers in the absence of direct evidence of market information to substantiate claims about market trends.

The Department argued that Xcel did not provide sufficiently detailed or persuasive explanations for the substantial variances in its cost forecasts from year to year. Responding to Xcel's statement that insurance budgets vary "for numerous reasons, including overall market conditions, inflation, and actual experience," the Department characterized this explanation as overly general and unconvincing.

In response to Xcel's contention that the increases are driven by a general upward trend in claim experience for primary casualty insurance due to increasing catastrophic events, the Department stated that primary casualty is just one of multiple insurance programs and can account for only a small portion of the overall increase. Moreover, noting that Xcel testified that it does not carry insurance for certain utility plant in part because of market volatility and because other utilities that are more prone to natural disasters have driven up premiums, the Department argued that insurance Xcel does not carry cannot be the driver of its increased insurance costs.

Citing Xcel's testimony that insurers develop premiums based on each utility's unique risk profile and that Xcel does not face the same risk as other utilities for hurricanes and wildfires given its geographic location, the Department argued that this testimony contradicted the notion that a rising risk of hurricanes and wildfires contributed to increased premiums for Xcel.
In response to Xcel's testimony that its actual 2022 insurance expense was on track to be within 0.4% of the forecasted value as of late 2022, the Department asserted that the Company did not verify whether that late-2022 projection was accurate or remained true for the full year's costs when 2022 was complete.

Further, the Department challenged Xcel's adherence to the same forecasting process it has used in the past to budget for insurance expense, arguing that this process has yielded inaccurate, overstated forecasts since 2017, which a particularly large gap between forecasted and actual insurance expense in 2021.

In light of its positions that Xcel's forecasting process (1) has not been substantiated with sufficient evidence in the record and (2) has significantly overestimated insurance expense in past years, the Department argued that a more reliable and reasonable approach would be to ground insurance-premium forecasting in historical trends from Xcel's actual average insurance-expense growth over a range of recent years.

The Department analyzed Xcel's past insurance spending data to determine the average annual percentage increase Xcel incurred for insurance premiums from 2017–2021. The Department then applied that average percentage increase to Xcel's actual 2021 insurance expense to calculate a proposed insurance budget for 2022. For 2023 and 2024, the Department applied the same year-over-year percentage increases Xcel proposed for those years, starting from the Department's reduced 2022 insurance budget amount.

The Department's proposed adjustments of reducing the 2022 percentage increase to align with the historical average but maintaining Xcel's requested percentage increases for 2023 and 2024 would reduce the revenue-requirement insurance expenses by approximately $9 million to $11 million in each year of the rate plan.

2. Xcel

Xcel opposed the Department's recommended adjustment, arguing that historical insurance costs are not reliable predictors of future insurance costs and that an insurance-premium forecast must be based on a thorough investigation with input from insurance brokers on general trends in insurance markets. Xcel asserted that the Department did not refute the Company's evidence of insurance market trends or identify any flaws in the Company's process for forecasting insurance expense. It characterized the Department's arguments as unreasonably retrospective and argued that the size of the forecasted costs compared to past actual costs is not a good reason to reject the forecasts Xcel developed based on prospective market trends.

Xcel attributed the substantial increases in its forecasted insurance expense to a "hardening" market, meaning that insurance companies are generally increasing premiums pursuant to supply-and-demand principles as a result of large claims industrywide or reduced insurance capacity. Xcel stated that hardening in the market is causing increased premiums in its master property insurance and excess liability insurance programs. In the area of primary casualty insurance, Xcel contended that insurance premiums are increasing due to a general upward trend in claim experience driven by an increase in catastrophic events such as gas explosions, hurricanes, and wildfires.

Xcel asserted that its insurance-premium forecasting methodology was an accurate predictor of its 2022 insurance costs. Xcel stated that the Company's actual 2022 insurance expenditures as of late 2022 were on track to be within about 0.4% of the Company's forecasted insurance expense for 2022.

Additionally, Xcel contended that its actual insurance expense for 2021 would have been close to its forecasted amount if not for the receipt of certain unforecastable surplus distributions from mutual insurance pools that were much larger than expected. In particular, Xcel in 2021 received a large distribution from its nuclear mutual insurance pool (Nuclear Electric Insurance Limited, or NEIL) because NEIL experienced either lower claims or higher investment returns than it had anticipated and reflected in its premiums. Xcel credits any expected NEIL distributions against forecasted premiums in its insurance budgets; however, distributions from NEIL fluctuate significantly from year to year because of NEIL's varying investment results and loss experience and, therefore, Xcel cannot forecast these distribution amounts with high accuracy or certainty.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel met its burden to support its proposed insurance-premium expenses for 2022–2024 and recommended that the Commission approve the Company's proposed amounts without the Department's recommended adjustment.

The ALJ found persuasive the Company's testimony that an increase in catastrophic events such as hurricanes and wildfires is generally driving up primary casualty insurance premiums across the industry.

Additionally, in finding that Xcel demonstrated the accuracy and thoroughness of its insurance-expense forecasting method, the ALJ was persuaded by the small size of the variance between the forecast and actual expenses in 2022.

D. Commission Action

Respectfully, the Commission disagrees with and will not adopt the ALJ's findings and recommendation regarding Xcel's proposed insurance-premium expense. Instead, the Commission will require Xcel to apply the Department's recommended adjustments to the 2022–2024 test-year and plan-year insurance-expense amounts.

Xcel's request relied heavily on overly generalized and indirect testimony about insurance-market trends. For example, Xcel filed a general summary of information purportedly received from insurance brokers rather than providing evidence directly from the brokers or other industry experts so that parties could cross-examine the sources of the market-trend claims and assess their credibility. Given the magnitude of the insurance costs Xcel seeks to recover from ratepayers and the substantial departure from historical trends in this cost category, the burden of persuasion required more robust record development to support Xcel's request on this issue.

Although the ALJ credited Xcel's slightly more specific explanation for expecting higher premiums for primary casualty insurance, Xcel did not detail a link between the increasing catastrophic events and claim experience and the specific premium amounts estimated for each insurance program. Moreover, the few explanations Xcel offered for changes in the markets relative to specific insurance programs relate to only a small subset of the Company's insurance programs and cannot explain the claimed cost increases in all the insurance programs the Company maintains. Moreover, Xcel did not persuasively show that the factors it cited as affecting the insurance markets are so substantial and consequential in Xcel's insured locations that they fully account for the expansive differences between Xcel's proposed insurance expenses for 2022–2024 and its actual insurance expenses incurred from 2017–2021.

The Commission also is not persuaded that Xcel's adherence to the same forecasting methods it has used in past years lends credence to the resulting 2022–2024 estimates. The record shows that Xcel's process significantly over-forecasted insurance expenses from 2017–2021, and these past performances call into question the accuracy of the forecasts produced through the same process in this case.

Xcel's argument that its 2021 actual insurance expense would have been close to the forecasted value if not for a larger-than-expected NEIL distribution is not a persuasive reason to accept the Company's forecasting process amid the other concerns raised in the record. Xcel routinely budgets for estimated NEIL distributions to be credited against its insurance premiums each year, and these distribution amounts fluctuate significantly and unpredictably. The record does not suggest that the 2021 NEIL distribution was an anomaly that can reasonably be excluded from consideration when evaluating the accuracy of Xcel's 2021 forecast; rather, varying distributions from mutual insurance pools appear to be a continuing issue equally likely to affect future years in unanticipated ways as they have in past years.

Xcel's claim that its forecast was closer to the actual expense in the singular year of 2022—the accuracy of which Xcel did not substantiate—is not enough to outweigh the substantial over-collection in this expense category demonstrated throughout the preceding years so as to persuade the Commission of this method's merits.

Having found that Xcel has not met its burden to support the requested amount of insurance-premium expense, the Commission will exercise its discretion to identify substitute values that reasonably approximate representative insurance costs based on the record and will result in just and reasonable rates.

Where costs fluctuate from year to year based on multiple factors beyond the Company's control and are difficult to predict, it is often reasonable to consider historical averages over a range of years in setting test-year costs.

Based on the record of variability in net insurance expense each year, the Commission finds that the Department's proposal to project 2022–2024 insurance costs based on historical trends in Xcel's actual insurance expenditures over a recent multiyear period is reasonable and is the approach most strongly supported by the record. The Commission will therefore require Xcel to calculate its 2022 test-year insurance-expense amount by applying the annual average percentage change in the Company's actual insurance expense from 2017–2021 to its actual 2021 insurance expense amount, and then calculate 2023 and 2024 plan-year values by applying the increase percentages Xcel proposed to use for those years.

Accordingly, the Commission will require Xcel to adjust its insurance-premium expenses as proposed by the Department, reducing the revenue requirement by $9.274 million in 2022, $10.017 million in 2023, and $11.311 million in 2024 for the Minnesota electric jurisdiction.

XXV. Organizational Dues

A. Introduction

Xcel's rate request included dues the Company pays for membership in certain utility associations and chambers of commerce. Parties disagreed about whether the Company should recover dues for the following organizations: (1) Edison Electric Institute (EEI) (2) the American Gas Association (AGA), and (3) 68 chambers of commerce.

Additionally, as a threshold matter, parties disagreed about which legal standard applies to the disputed organizational dues and whether certain filing requirements apply.

B. Legal Standard

Under Minn. Stat. § 216B.16, subd. 17, a utility may not recover as operating expenses "a public utility's travel, entertainment, and related employee expenses" if the Commission finds those expenses to be unreasonable and unnecessary for the provision of utility service.[35] To assist the Commission in evaluating which of these expenses are recoverable, a utility filing a general rate case petition must include "a schedule separately itemizing all travel, entertainment, and related employee expenses" including "dues and expenses for memberships in organizations or clubs" and other categories identified by statute or by the Commission.[36]

1. Positions of the Parties

Parties disagreed about whether Minn. Stat. § 216B.16, subd. 17, applies to the organizational dues at issue in this case. Expenses falling under subdivision 17 must be itemized separately and are not recoverable if they are "unreasonable and unnecessary for the provision of utility service."

The OAG argued that organizational dues fall under subdivision 17 regardless of whether the dues relate to individual employee memberships or corporate memberships and regardless of whether the utility pays the dues directly to the organization or reimburses an individual employee who first pays the dues to the organization. The OAG contended that the itemized information required by subdivision 17 is necessary to allow ratepayer advocates and the Commission to evaluate the recoverability of these expenses.

Xcel disagreed, contending that subdivision 17 applies only to expenses that are incurred by an individual employee, tracked through the Company's expense-reporting system, and then reimbursed to the individual employee consistent with the Company's employee expense policy. The EEI, AGA, and chamber dues at issue in this case are paid directly to the organizations by Xcel, not incurred by individual employees and then reimbursed through the expense-reporting system, so Xcel argued that these expenses are not within the scope of subdivision 17.

Instead of applying the employee-expense standard from subdivision 17, Xcel contended that these EEI, AGA, and chamber dues should be analyzed under the ordinary legal standard that governs all expenses in rate cases: Rates must be just and reasonable, balancing the interests of the utility, its shareholders, and its customers.

2. Recommendation of the Administrative Law Judge

The ALJ concluded that the dispute about the applicability of subdivision 17 does not materially affect the rate-recovery analysis in this case. Although subdivision-17 employee expenses are subject to specific itemization and filing requirements, the ALJ found that the "[not] unreasonable and unnecessary" standard in subdivision 17 is consistent with the general ratemaking standard that all rates be just and reasonable giving due consideration to the utility's need to meet the cost of furnishing service.[37] The ALJ noted that Minn. Stat. § 216B.16, subd. 19 (the multiyear rate-plan statute) requires that rates "be based only upon the utility's reasonable and prudent costs of service," and that the Commission routinely examines the need for and reasonableness of utility expenses outside the context of employee expenses under subdivision 17.

[35] Minn. Stat. § 216B.16, subd. 17.

[36] *Id.*

[37] *See* Minn. Stat. § 216B.16, subds. 4, 6.

Having determined that the distinction is not material to the rate-recovery analysis, the ALJ declined to decide whether the organizational dues at issue constitute employee expenses subject to subdivision 17. However, because the utility has the burden to establish the recoverability of all claimed expenses by a preponderance of the evidence, the ALJ noted that Xcel bears the risk that the Commission may find that an expense is not adequately supported and therefore deny recovery if the Company provides less detail. In other words, even if an expense does not strictly fall under the requirements of subdivision 17, providing detailed, itemized information is likely to help Xcel meet its burden under either standard.

The ALJ recommended that the Commission evaluate rate-recoverability of corporate organizational dues on a case-by-case basis in light of the facts of the case. Additionally, for the Company's next rate case filing, the ALJ stated that the Commission may impose any specific filing requirements that the Commission deems necessary to evaluate the recoverability of any organizational dues.

3. Commission Action

The Commission concurs with the ALJ that, as applied to the specific questions of recoverability of the organizational dues at issue herein, the legal standard expressed in Minn. Stat. § 216B.16, subd. 17(a) is functionally equivalent to the general legal standard that governs all utility expenses, such that applying either standard does not alter the outcome of the recoverability analyses in this case.

Although the ALJ did not make a recommendation as to the legal applicability of subdivision 17, the Commission will require Xcel in future rate cases to provide the information identified in Minn. Stat. § 216B.16, subd. 17, for all costs it seeks to recover for organizational dues, including chamber-of-commerce dues, regardless of membership type and regardless of whether the Company paid the organization directly or reimbursed an employee for the expense.
The Commission is not persuaded by Xcel's argument that subdivision 17 applies only to expenses first incurred by individual employees and subsequently reimbursed by the Company.

Nothing in the statutory language implies any limitation based on whether the expenses were incurred by an employee and reimbursed or paid by the utility directly to the organization. To the contrary, subpart (b) of subdivision 17 requires separate itemization for certain subpart (a) expenses "incurred by *or on behalf of*" certain employees or board members, indicating that expenses incurred by the Company directly and not reimbursed to an employee may also fall within the scope of subdivision 17.[38]

Moreover, as the ALJ noted, the Commission has authority to impose specific filing requirements that are necessary to evaluate the recoverability of utility expenses. The Commission agrees with the OAG that the itemized expense data identified in subdivision 17 is necessary to facilitate thorough examination of Xcel's organizational dues expenses for both institutional and individual-employee memberships, whether paid directly by the utility to the organization or reimbursed to an individual employee, so that the Commission may determine whether the expenses are recoverable.

[38] Minn. Stat. § 216B.16, subd. 17(b) (emphasis added)

C. Edison Electric Institute

EEI is a trade organization that represents investor-owned electric companies in the United States. Xcel's estimated EEI dues for the Minnesota jurisdiction are $1.021 million in 2022, $1.011 million in 2023, and $1.012 million in 2024.

1. Positions of the Parties

The OAG opposed Xcel's request to recover EEI dues, arguing that Xcel has not met its burden to prove that membership in this organization is reasonable and necessary for the provision of electric service or benefits ratepayers. The OAG principally argued that because EEI engages in lobbying and related advocacy on behalf of its members, the Commission should closely scrutinize these dues to ensure that ratepayers are not made to pay for advocacy activities that are not sufficiently tied to the provision of utility service and beneficial to customers.

Although Xcel removed from its request the percentage of dues that EEI reports as being for lobbying activities as defined by the IRS, the OAG argued that excluding this percentage from the total dues is not sufficient to prove that the remaining expenses are reasonable and necessary for the provision of utility service. Rather, the OAG argued, it is Xcel's burden to make an affirmative showing as to the value of and need for EEI's services—a burden that has not been met in this record.

Just Solar echoed the OAG's arguments opposing Xcel's EEI request. Additionally, Just Solar argued that requiring Xcel's customers to pay for these dues would effectively compel customers to subsidize EEI's speech activities in violation of First Amendment free-speech protections. Xcel asserted that membership in EEI provides important benefits to customers including public policy leadership, strategic business intelligence, and essential conferences and forums, and provides services that Xcel cannot duplicate on its own such as critical industry data and training. In response to the OAG's assertion that it is unreasonable to rely on the lobbying-activities percentage identified by EEI, Xcel stated that there is no practical way for Xcel to independently review EEI's activities and determine which ones constitute lobbying under some standard other than the widely used IRS definition.

2. Recommendation of the Administrative Law Judge

The ALJ found that EEI dues provide some ratepayer benefits but that Xcel failed to meet its burden to show that EEI's method of distinguishing lobbying and non-lobbying expenses is sufficient to rely upon as a basis to conclude that the non-lobbying portion is fully recoverable. Therefore, the ALJ recommended that the Commission adopt the OAG's recommendation to remove Minnesota jurisdictional amounts of $1,021,000 from the 2022 test year, $1,011,000 from 2023, and $1,012,000 from 2024.

3. Commission Action

The Commission respectfully disagrees with the ALJ's findings and will approve Xcel's request to recover EEI dues. Xcel met its burden to explain how membership in EEI benefits customers by providing critical industry data and training, public policy leadership, strategic business intelligence, and essential conferences and forums to enhance Xcel's ability to serve customers.

Additionally, Xcel demonstrated that it excluded from its request the portion of dues EEI designated for lobbying to protect customers from paying for activities that do not benefit them.

The Commission recognizes the OAG's concerns that EEI may use dues to engage in policy advocacy that promotes utilities' interests over customers' but falls short of the IRS definition of lobbying and, thus, is not excluded from rates through the provided percentage. However, Xcel persuasively argued that it would not be reasonably practical to require the Company to conduct an independent audit of all of EEI's activities to confirm whether there is any policy advocacy against utility customers' interests under a standard broader than the IRS definition. Under the circumstances, the Commission is not persuaded that the OAG's concerns warrant denying recovery of these dues which have been shown to be beneficial in the provision of utility service.

Based on the demonstrated customer benefits and Xcel's exclusion of the EEI-identified lobbying-related portion from the recovery request, the Commission will approve Xcel's request to recover, on a Minnesota jurisdictional basis, $1,021,000 for 2022, $1,011,000 for 2023, and $1,012,000 for 2024 for EEI dues.

D. American Gas Association

The AGA is an industry association for companies that engage in activities associated or affiliated with the natural gas industry. Xcel's estimated AGA dues for the Minnesota jurisdiction are $365,000 in 2022, $361,000 in 2023, and $362,000 in 2024.

1. Positions of the Parties

The OAG opposed Xcel's request to recover AGA dues. Noting that AGA activities focus on the natural gas industry, the OAG argued that Xcel has not established that membership in the AGA is reasonable and necessary for the provision of electric service and has not established a clear connection between AGA membership and the improvement of electric utility service to benefit electric customers.

Just Solar joined the OAG's arguments against recovery of AGA dues and added that requiring Xcel's customers to pay for AGA dues would violate First Amendment free-speech protections by compelling customers to subsidize the AGA's speech activities.

Xcel contended that its AGA membership provides significant benefits to the Company's electric operations and electric customers by helping the Company to manage procurement of natural gas for its gas-fired electric generation facilities and to handle the location of gas lines safely. Additionally, Xcel stated that the AGA is a leader in the development of clean hydrogen technology, which is an element of the Company's decarbonization vision.

2. Recommendation of the Administrative Law Judge

The ALJ found Xcel's arguments persuasive and recommended that the Commission approve the Company's requested recovery of AGA dues.

3. Commission Action

The Commission respectfully disagrees with the ALJ's findings and will preclude Xcel from recovering AGA dues in electric rates.

The AGA represents energy companies that deliver natural gas, and its activities focus on the gas industry. Although Xcel uses gas at some of its electric-generation facilities, the rates at issue in this case are for Xcel's electric service, not gas service. Xcel has not provided substantial, persuasive evidence demonstrating that its membership in the AGA is reasonable and necessary for the provision of electric service, that its electric utility service would be diminished or its quality reduced without AGA membership, or that AGA membership materially benefits its electric customers. The record does not establish a sufficient connection between AGA activities and benefits to Xcel's electric customers to justify requiring Xcel's electric customers to pay these costs.

The Commission will therefore require Xcel to remove from its revenue requirement Minnesota jurisdictional amounts of $365,000 for 2022, $361,000 for 2023, and $362,000 for 2024 for AGA dues.

E. Chambers of Commerce

1. Introduction

Xcel requests to recover $156,286 in each year of the rate plan for dues paid to 68 different chambers of commerce. The requested amount represents the full Minnesota jurisdictional share of Xcel's chamber dues, excluding portions the chambers attributed to lobbying.

Under Minn. Stat. § 216B.16, subd. 13, the Commission may (but is not required to) allow rate recovery of expenses incurred for economic and community development. The Commission's traditional practice has been to allow utilities to recover only half of their economic-development costs through rates, leaving shareholders to bear the other half. The primary reason for limiting ratepayers' share of these costs is because economic development in a utility's service area often leads to increased electric usage, which typically increases the utility's revenue and profits, thus benefiting shareholders.

The parties in this case did not dispute that only 50% of economic development expenses should be recovered from ratepayers because economic development within a utility's service territory tends to benefit the utility's shareholders as much as it benefits customers. However, they disagreed about whether the dues Xcel pays to chambers of commerce should be characterized as economic-development expenses subject to this recovery limit.

2. Position of the Parties

The OAG recommended that Xcel's recovery be limited to 50% of the non-lobbying dues it pays to be a member of any state, regional, or local chamber of commerce because these organizations engage in economic-development activities that benefit Xcel's shareholders. The OAG stated that over 85% of the chambers identified the objective of furthering business and economic activity in their mission statements. The OAG's requested 50% adjustment would reduce Xcel's revenue requirement by $78,143 in each year of the rate plan.

Xcel argued that chambers of commerce play roles in their communities beyond economic development, such as fostering relationships and strengthening community ties. Xcel contended that, by paying dues and participating in chambers of commerce, the Company demonstrates its support for and commitment to those communities and improves its ability to respond to the needs of customers in those communities. Xcel also stated that chamber activities provide a vehicle to interact with customers so it can better serve them. Because chamber-of-commerce membership provides the Company and local customers these other benefits, Xcel argued that chamber dues should not be considered economic-development investments.

3. Recommendation of the Administrative Law Judge

The ALJ found that membership in the various chambers of commerce provides a ratepayer benefit beyond economic development. Therefore, the ALJ recommended that the Commission allow Xcel to recover the full amount requested for chamber-of-commerce dues and not adopt the OAG's recommended adjustment.

4. Commission Action

The Commission respectfully disagrees with the ALJ's recommendation and will require Xcel to reduce its recovery of chamber-of-commerce expenses by 50%.

As the OAG noted, the vast majority of the chambers of commerce identified in the record highlight furthering business and economic activity in their mission statements. Thus, it is reasonable to conclude that at least some of the dues Xcel contributes to these organizations will be used for economic development in the Company's service territory and should therefore be limited to 50% recovery under the parties' agreed upon practice for economic-development expenses.

Although Xcel provided evidence suggesting that chamber-of-commerce membership yields some benefits beyond economic development, Xcel has not proposed any way to quantify the relative proportions of economic-development and non-economic-development benefits. The record offers no guidance for designating a specific percentage of the total chamber-of-commerce expense category as being associated with economic development so that the 50% limitation may be applied only to that portion while the Company recovers 100% of the chamber dues associated with other benefits.

The Commission has discretion to disallow economic-development costs under Minn. Stat. § 216B.16, subd. 13. The utility bears the burden to show that any requested rate increase is just and reasonable, and any doubt as to reasonableness is to be resolved in favor of the consumer.[39]

In this case, the record shows that at least some portion of Xcel's chamber-of-commerce expense is incurred for economic development, and Xcel has not met its burden to show that any particular portion of this expense category (or its requested 100%) is *not* associated with

[39] Minn. Stat. § 216B.16, subd. 4; Minn. Stat. § 216B.03.

economic development. Therefore, resolving doubts in the consumer's favor, the Commission finds it reasonable to limit recovery of Xcel's chamber-of-commerce expense to 50%. This adjustment will reduce Xcel's revenue requirement by $78,143 in each year of the rate plan.

XXVI. Carbon-Free Future MN Coalition

A. Introduction

Xcel's revenue request includes $935,946 for 2022, $93,595 for 2023, and $93,595 for 2024 associated with the Carbon-Free Future MN Coalition.

Xcel described the Carbon-Free Future MN Coalition as an initiative to educate non-traditional stakeholders about the Company's carbon-free energy vision, its plans for transitioning to clean energy, and how stakeholders can engage in discussions of the transition process. Xcel stated that some of these funds were used to make presentations to customers, communities, membership organizations, chambers of commerce, environmental advocacy groups, individuals, and other stakeholders regarding various elements of the Company's resource plan related to the clean-energy transition. Xcel argued that helping stakeholders to understand the Company's transition plans would better position stakeholders to be able to support an ambitious clean-energy future if they so choose.

B. Positions of the Parties

The OAG recommended that the Commission disallow recovery of Xcel's claimed 2022–2024 Carbon-Free Future MN Coalition costs. The OAG questioned whether these expenses should have been disclosed as lobbying expenses and argued that Xcel had not provided sufficient evidence to support its requested amounts or to show that it is just and reasonable to recover these costs through rates.

Xcel asserted that it did not view the Carbon-Free Future MN Coalition as a lobbying program and maintained its request to recover the full amount claimed.

C. Recommendation of the Administrative Law Judge

The ALJ did not make a recommendation on this issue.

D. Commission Action

The Commission will require Xcel to remove all 2022–2024 Carbon-Free Future MN Coalition costs from the revenue requirement, totaling $935,946 for 2022, $93,595 for 2023, and $93,595 for 2024. The activities underlying these costs appear similar to lobbying activities directed at the Commission and the Legislature, which are not recoverable, and Xcel has not demonstrated that the costs are related to recoverable activities or necessary to provide service to customers.

XXVII. Advertising Costs

A. Introduction

Xcel's revenue request includes $317,439 in each year of the MYRP for expenses identified as FERC Account 912 "Customer Program – Advertising" and "Customer Program – Promotion" costs. FERC Account 912 is a type of federally regulated account that utilities maintain for certain costs incurred in "promotional, demonstrating, and selling activities."[40]
In Xcel's initial filing, FERC Account 912 items were marked as "economic development." As noted above, the parties agreed that only 50% of economic-development costs should be recovered from ratepayers.

B. Positions of the Parties

Because Xcel's initial filing identified FERC Account 912 costs as economic development, the OAG argued that only 50% of these costs should be recovered through rates.

Xcel maintained that its FERC Account 912 costs should be fully recovered, asserting that they are not economic-development costs and were only mislabeled as such through inadvertence. Xcel stated that these costs are actually "demonstrating and selling expenses" consistent with the federal regulations governing this type of account. Further, Xcel argued that the costs shown reflect a reasonable level of advertising costs to include in rates and that the advertising samples included in the Company's initial filing further demonstrate their reasonableness.

Disputing Xcel's assertion that the costs were inadvertently mislabeled, the OAG argued that Xcel failed to provide examples of these advertisements sufficient to prove their recoverability. Accordingly, the OAG argued that Xcel failed to meet its burden and recommended that the Commission resolve doubt in favor of consumers by limiting recovery to 50% for these costs.

C. Recommendation of the Administrative Law Judge

The ALJ found Xcel's explanation of inadvertent mislabeling persuasive and found that the costs attributed to FERC Account 912 are fully recoverable advertising expenses, not related to economic development. The ALJ further found that the costs requested by the Company reflect a reasonable level of advertising costs to include in rates for 2022–2024. The ALJ noted that the OAG had the opportunity to review Xcel's provided advertising samples and did not identify any samples that appeared to be related to economic development.

The ALJ therefore recommended that the Commission approve Xcel's proposed FERC Account 912 expenses and not adopt the OAG's recommended adjustment.

D. Commission Action

The Commission concurs with the ALJ that Xcel adequately supported its FERC Account 912 costs and persuasively explained that the mislabeling as economic development does not warrant

[40] *See* 18 C.F.R. § 367.9120.

a 50% adjustment. The Commission will therefore approve recovery of these expenses as proposed by Xcel.

RATE OF RETURN

XXVIII. Capital Structure

To determine an overall rate of return for Xcel Energy, it is necessary to determine the amount of long-term debt, short-term debt, and common equity needed by the Company to finance its operations (the capital structure) and the cost of each of these components.

The Company proposed the following capital structure.

Table 2
Proposed Capital Structure

Type of Capital	2022	2023	2024
Long-Term Debt	46.89%	46.50%	47.08%
Short-Term Debt	0.61%	1.00%	0.42%
Common Equity	52.50%	52.50%	52.50%
Total	100%	100%	100%

No party opposed the Company’s proposal, and the Commission concurs on its reasonableness.

XXIX. Cost of Debt

Xcel proposed the following costs of long-and short-term debt, which reflects the weighted average cost of each individual debt issuance anticipated in each of the years listed below. Typically, short-term debt is any financial obligation that is due in less than one year whereas long-term debt is any financial obligation due later than one year.

Table 3
Xcel’s Proposal

Type of Debt	2022	2023	2024
Long-Term Debt	4.13%	4.12%	4.06%
Short-Term Debt	0.94%	0.80%	1.47%

In response to the Company’s proposal, the Department recommended that the costs be adjusted upward to reflect the impact of increased interest rates, as shown in the table below.

Table 4
The Department’s Proposal

Type of Capital	2022	2023	2024
Long-Term Debt	4.19%	4.33%	4.40%
Short-Term Debt	3.73%	3.50%	4.17%

Ultimately, the Company agreed on the reasonableness of the Department's calculations. The Commission also concurs on the reasonableness of these calculations and will approve them. While the Commission has not approved a revised cost of debt in a rate case proceeding in over a decade, in this instance, the Commission concurs on the reasonableness of these calculations, which reflect increases in interest rates due to inflationary factors. The approximate revenue requirement impact of this upward revision is equivalent to an additional 30 return-on-equity basis points.

XXX. Rate of Return on Equity

A. Introduction

In determining just and reasonable rates, the Commission is required to

> give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, *and to earn a fair and reasonable return upon the investment in such property*.[41]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances utility infrastructure. The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

All parties in this proceeding point to two decisions of the United States Supreme Court to provide further explanation as to how a fair and reasonable return should be calculated—the *Hope* and *Bluefield* decisions.[42] In particular, the *Bluefield* Court held:

> A public utility is entitled to such rates as will permit it to a return . . . equal to that generally being made at the same time . . . on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[43]

The *Hope* Court further explained:

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure

[41] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

[42] *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 43 S. Ct. 675 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281 (1944).

[43] *Bluefield*, 262 U.S. at 692–93.

> confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[44]

B. The Analytical Tools

Xcel, the Department, XLI, and CUB conducted cost-of-equity studies and based their analyses on comparison groups of utilities they considered similar enough to Xcel to serve as proxies in determining the Company's cost of equity.

The Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance, uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, market equity prices, and growth rates.

The three DCF models in this record include: constant growth, two-growth (or two-stage), and multi-stage. Constant growth DCF is used where dividends are expected to grow at a constant rate over time. Two-growth DCF uses growth forecasts to model dividend growth in years one through five and then applies a different growth rate for years six and beyond. Multi-stage adds a transition period between short- and long-term growth. The basic approach is, for both the two-stage and multi-stage DCF, to recognize that unusually low or high growth rates are unlikely to continue in the long term, and to adjust them in later years of the model.

The Company and the Department also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. This model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment; adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on all market equities; and multiplying the remainder by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

Xcel also conducted an Empirical CAPM study, which addresses the tendency of the CAPM to underestimate the cost of equity for companies with lower beta coefficients (in effect, lower return potential) such as regulated utilities. It recognizes the results of academic research showing that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.

The Predictive Risk Premium model, also used by Xcel, is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. According to RPM theory, an estimate of a common equity risk premium over bonds (either historically or prospectively) is used to derive a cost rate of common equity. The Total Market Approach Risk Premium model develops three different equity risk premiums, using different measures for those premiums.

[44] *Hope*, 320 U.S. at 603.

CUB used the Residual Income model, a method of determining a cost of equity using the current stock price, the book value of equity (per share), return on equity, and long-run sustainable growth.

C. Proxy Groups

As noted above, the standard method for estimating the cost of equity would normally begin by examining the price of the utility's stock, but Xcel is a subsidiary of Xcel Energy, Inc. and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks.

A standard method for estimating the cost of equity of a private company like Xcel is to develop a proxy group of publicly–traded companies that pose similar risks to equity investors as the non-public company and then apply cost models to the members of the proxy group to infer the non-public company's cost of equity.

The Company, the Department, XLI, and CUB each developed criteria used to screen companies to identify those most analogous to Xcel. These criteria included such factors as whether the company is a vertically integrated utility, what percentage of its operating income is derived from regulated electric distribution operations, dividend growth rate projections, and whether it was involved in a recent merger, among others.

Xcel and the Department updated their proxy groups throughout the proceeding to account for changes in circumstances affecting companies that no longer met their screening criteria. Xcel began with 13 companies, then removed two and added one. The Department started with a very similar list of companies, then removed one and added one, for a total of 16 companies. XLI included 12 companies, nearly identical to the Company's with the exception of excluding Xcel Energy, Inc., (Xcel's parent company) from the list. CUB developed a proxy group of 38 companies that included a broader range of companies with a central similarity being a shared industry.

In addition to these proxy groups, Xcel developed a list of 39 companies that comprised the Company's non-price regulated proxy group. These included entities identified based on different criteria other than those used by the Company's utility proxy group. Primarily, they are domestic, non-price regulated companies, not utilities, who are similar in total risk to the utility proxy group. They have beta coefficients that are within plus or minus two standard deviations of the average unadjusted beta coefficients of the utility proxy group; beta coefficients measure market, or systematic, risk, which is not diversifiable. This proxy group includes diverse companies such as Alphabet, Inc., Lockheed Martin, and Pfizer.

D. Positions of the Parties

1. The Company

a. Proposed Return-on-Equity

Xcel proposed a return on equity of 10.20% based on the results of multiple models and proposed adjustments, including an adjustment for flotation costs.[45]

Xcel's initial set of data, representative of market conditions as of August 2021, shows the following results of its models.

Table 5
Xcel's Initial Filing

Model/Analysis	Result, Adjustment Amount, or Range
Discounted Cash Flow Model	8.78%
Risk Premium Model	10.95%
Capital Asset Pricing Model	12.53%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.24%
Indicated Range of Common Equity Cost Rates Before Adjustments	9.65% - 11.65%
Business Risk Adjustment	0.05%
Credit Risk Adjustment	-0.13%
Flotation Cost Adjustment	0.08%
Indicated Range of Common Equity Cost Rates after Adjustment	9.65% - 11.65%
Recommended Cost of Common Equity	10.20%

Xcel's DCF results of 8.78% above is calculated based on the results of *both* DCF models, the constant growth and two-stage growth models. The Company took the average of the mean and median of both models to calculate its DCF-indicated common equity cost rate for the utility proxy group. The average, as calculated by the Company, of the constant growth model is

[45] Flotation costs are associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs. Due to issuance costs, the price an investor pays for a new share is higher than the price the company issuing the new share receives. As a result, utilities frequently request an adjustment to their return.

8.83%, while the average of the two-growth model is 8.72%; the Company then averaged these results to arrive at 8.78%.

The Company also considered the results of its non-price regulated proxy group results, as well as adjustments and other models. According to the Company, its recommended return fairly balances the interests of customers and shareholders, is consistent with applicable law, and would maintain the Company's financial integrity and ability to attract capital at reasonable rates.

The Company subsequently updated its analysis based on market conditions in September 2022 but continued to recommend that the Commission authorize a return on equity of 10.20%.

The Company explained that inflationary and other market factors led to an increase in its analytical results, as shown in the table below.

Table 6
Xcel's Updated Results

Model/Analysis	**Result, Adjustment Amount, or Range**
Discounted Cash Flow Model	9.30%
Risk Premium Model	11.65%
Capital Asset Pricing Model	12.06%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.91%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.10% - 12.10%
Business Risk Adjustment	0.05%
Credit Risk Adjustment	-0.18%
Flotation Cost Adjustment	0.08%
Indicated Range of Common Equity Cost Rates after Adjustment	10.05% - 12.05%
Recommended Cost of Common Equity	10.20%

Xcel again took the average of the mean and median results of both DCF models to calculate its DCF-indicated common equity cost rate for the utility proxy group. The average, as calculated by the Company, of the constant growth model is 8.80%, while the average of the two-growth model is 9.79%; the Company then averaged these results to arrive at 9.30%.

In addition to requesting an adjustment for flotation costs, the Company also recommended that the Commission authorize an adjustment mechanism that would alter the return on equity each year of the rate case depending on changes in interest rates on long term utility bonds.

Finally, the Company discounted the returns recommended by other parties, stating that their approaches were flawed, their results therefore skewed, and their adjustments unreasonable, as discussed in further detail below.

2. The Department

The Department offered the results of several DCF models, as well as the results of the CAPM model, in its filings. In recommending a return of 9.25%, the Department stated that the results of its multi-stage DCF analysis are the most reliable and a reasonable starting point for setting a return.

The multi-stage DCF has three stages. In years one through five (the first stage), the model assumes that dividends grow at the forecasted growth rates predicted by equity analysts for the proxy group companies. In the second stage, a proxy company's dividend growth rate moves linearly from the equity analyst growth rate to projected growth of GDP (i.e., the value of the total output of goods and services in the national economy). In the third stage, the model assumes that dividends for the proxy group companies grow at the same rate as GDP.

The Department used two different intervals for the second stage transition period: 10 years and 20 years. The Department filed initial and updated data, including stock prices, dividends, and forecasted growth used as modeling inputs to reflect changes in market conditions. The table below shows the updated results of each of the Department's models, adjusted to include flotation costs.

Table 7
Department Summary of Updated Model Results

	Mean Low ROE	Mean Average ROE	Mean High ROE
Multi-Stage DCF with 10-year second stage	7.83%	8.50%	9.66%
Multi-Stage DCF with 20-year second stage	8.03%	8.74%	9.82%
Constant Growth DCF	9.04%	9.94%	10.68%
Two-Growth DCF	9.09%	9.88%	10.52%
CAPM w/10 Year Growth Transition Period	6.39%	6.75%	7.63%
CAPM w/20 Year Growth Transition Period	7.13%	7.43%	8.16%

The Department explained its rationale for relying on the results of its multi-stage DCF analysis, stating that financial literature demonstrates that equity analysts' long-term earnings growth forecasts are generally biased upwards, thus overestimating future growth. Such growth rates exceed GDP, which acts as a practical ceiling on perpetual growth rates. While the two-growth DCF includes an adjustment to eliminate outlier growth rates, the Department maintained that the model relies on growth rates that exceed expected GDP growth. A multi-stage DCF model solves this problem by assuming growth equal to GDP after either 10 or 20 years.

In assessing the results of the CAPM, the Department recommended against squarely relying on its results, stating that it has drawbacks that make it a poor tool for ratemaking. In particular, it relies on expert judgment at nearly every turn—for determining the term of the risk-free, interest-bearing investments used as a benchmark, determining the time frame for calculating growth rates, determining the beta that represents market volatility, and determining the historical periods over which to measure returns. This reliance on judgment is unlike the DCF as none of the CAPM's inputs are basic matters of fact and public record. According to the Department, the subjectivity of these judgments creates significant variation in their estimating inputs, which is compounded when the inputs are combined. The Department stated that it instead uses the CAPM as a check on the reasonableness of the results of the DCF analyses.

Finally, the Department opposed the Company's proposed adjustment mechanism that would be triggered in each year of the rate case depending on market conditions, stating that the Company had not quantified its proposed metric or otherwise filed its proposed calculations for determining the adjustment.

In response to the Department's recommended return of 9.25%, the Company stated that the Department's approach is not grounded in sound economic theory or a scholarly approach to the field of regulatory finance, stating that reliance on GDP to determine a return on equity unfairly discounts the return's correlation to the Company's need to attract capital.

The Company also rebuked the Department's upward adjustment from the results of its multi-stage analysis (a three-growth stage with a return of either 8.50% or 8.74% based on the average returns of the model using a second-stage growth rate of both 10 and 20 years). The Company stated that the Department's proposed upward adjustment to 9.25% from its results bears no principled relationship to the model's results.

3. XLI

XLI initially recommended a return of 9.17%, though it did not update its data after its initial filing as was done by both the Company and Department. XLI subsequently revised its recommended return to 9.16% based on a correction to its CAPM calculations.

XLI's range of results from all models is shown in the table below. The average results of its DCF constant-growth analysis is 8.60% and the average of its two-growth analysis is 8.55%. In developing its range of results for purposes of recommending a return on equity, XLI excluded the constant growth DCF low result due to its use of unreasonably low growth assumptions; XLI instead relied on the two-growth DCF to set the lower end of the range and used the constant-growth DCF high result for the upper end.

In arriving at a 9.16% recommended return, XLI took the median of the results of its analyses, shown below.

Table 8
XLI Return on Equity Results

Model	**Return on Equity**
Low Single Stage DCF	7.23%
Mean Single Stage DCF	8.60%
High Single Stage DCF	10.28%
Two Stage DCF	8.55%
Historical CAPM	9.91%
Proj. S&P MRP CAPM	11.66%
Proj. Value Line MRP CAPM	14.46%
Risk Premium	9.42%
Median Return on Equity	**9.66%**

In recommending its return, XLI began with the median of returns from its results and then applied a downward adjustment of 50 basis points to account for the Company's lower-risk profile compared to the utilities in the proxy group. XLI based the adjustment on the fact that the Company has both a multi-year rate plan and sales true-up, as well as a mechanism for recovery of other investments between rate cases, which significantly offset the Company's risk.

XLI also recommended against adjusting the return to account for flotation costs, stating that such costs are incurred by the parent company (Xcel Energy, Inc.), not by the utility in this case, Xcel Energy. XLI also opposed the Company's proposed rate adjustment mechanism for the reasons described by the Department.

In response to XLI's recommended return of 9.16%, the Company stated that XLI mistakenly relied on long-term historical averages, rather than interest rates, to calculate the equity risk premium in its Risk Premium analyses; the Company also faulted XLI for not subsequently updating its DCF and CAPM analyses to reflect changes in market conditions, failings that the Company claimed produce unreasonably low average returns. The Company also stated that XLI's 50-basis point downward adjustment from the results of its analyses to account for the Company's low-risk profile was unfounded; XLI had not fairly considered that other comparable companies have similar rate mechanisms in place to Xcel's, such as a sales true-ups, that affect their risk profiles.

4. CUB

CUB applied a residual income model, which it explained as an algebraic re-expression of the DCF model, to all 38 electric utility stocks in the Value Line Investment Survey, resulting in a 7.00% cost of equity estimate. CUB applied a CAPM to the same list of 38 stocks, resulting in a cost of equity of 7.40%. Similar to the Department's approach, the Residual Income model assumes that growth does not exceed the GDP growth rate.

Based on its analysis, CUB recommended a return of between 8.80% and 9.00%, a range that CUB acknowledges is higher than the actual cost of equity. A fair return, CUB stated, is typically higher than the cost of equity. CUB stated that a reasonable return is justifiably lower than cost but that gradualism supports a result between 8.80% to 9.00% in this case. CUB explained that determining the degree to which a return should be higher than the cost of equity is unrelated to utility risk or financial models that are theoretical in nature but is rather a subjective determination based on public policy analysis, not corporate finance. CUB echoed the Department's position that identifying the cost of equity and then determining a fair return are essentially separate exercises. Identifying a reasonable return is rooted in judgment, which is the best approach to balancing finance variables and policy fairness.

In applying its approach to this case, CUB took into consideration the impacts of inflation on both the utility and its customers, stating that high short-run inflation rates hurt customers more than shareholders, pointing to data that showed Xcel's parent company's stock trading higher at the end of 2022 than it had the year prior. CUB stated that applying short-term high inflation rates to cost-of-equity analyses can skew the estimates of long-term growth rates in favor of the utility to the disadvantage of the ratepayer at a time when inflation is harming consumers.

Finally, CUB opposed the Company's proposed multi-year rate adjustment mechanism for the reasons explained by the Department.

In response to CUB's recommended return of between 8.80% and 9.00%, the Company stated that this recommendation echoes the flaws in the Department's analyses by relying on a presumption that utility returns have been set at unreasonably high levels for years. The Company again discounted this approach, stating that it is premised on public policy considerations instead of the reality of corporate finance.

5. The OAG

The OAG recommended against setting the return at Xcel's recommended level of 10.20%, stating that an increase of that magnitude—114 basis points above the Company's existing return of 9.06%—was not supported by the record. Noting that Xcel's recommended return was substantially higher than any return recommended by any other party, the OAG urged the Commission to rely on the analytical results and the recommendations of other parties in setting the return.

6. The Commercial Group

The Commercial Group supported the recommendations of the Department and XLI, stating that their analyses and recommendations better reflect investor expectations than the Company's. The Commercial Group also echoed opposition to the Company's proposed adjustment mechanism, aligning its reasoning with that of the Department, XLI, and CUB.

7. Just Solar Coalition

Just Solar Coalition recommended that the Commission reject Xcel's proposed return and instead set a return that more equitably considers the analyses and recommendations of CUB and the Department.

E. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission authorize a return on equity of 9.87%, based on the average results of the Company's DCF two-growth analysis as shown in its updated analysis.

In assessing the parties' proxy groups, she found that the utility proxy groups developed by the Company and the Department were not materially different and were both reasonably reliable. She found that one shortcoming of XLI's proxy group is that it was not subsequently updated to reflect market changes. She found CUB's 38-member proxy group to be too broad, and she was not persuaded by CUB's assertions that all firms in the same industry have nearly the same cost of capital, making a larger proxy group superior.

She also found that the Company's non-price regulated companies have dramatically different businesses from Xcel as well as from one another and that, as the Company acknowledged, as individual businesses, their risks have not been shown to be comparable to Xcel's. For this reason, she concluded that the Company's application of its models to the non-price regulated proxy group was unpersuasive in informing a return-on-equity determination.

In analyzing the parties' models and their results, she discounted the Department's reliance on GDP to estimate long-term growth in its multi-stage DCF analyses, finding that over the course of more than 50 years at least seven industries, including utilities, had grown faster than overall GDP. She also found that the CAPM has flaws that render it an unreliable single source for setting a return due its heavy reliance on an analyst's subjective judgment.

Based on extensive analysis of the record and the multitude of models, she found the two-growth DCF analysis in the record most reliable due to the model's accuracy in calculating growth rates and its use of relevant market data. In concluding that 9.87% is well-supported by the record, she stated that in the year between the filing of the rate case and the filing of rebuttal testimony, changes in the market environment had occurred, notably a significant increase in inflation as measured by the Consumer Price Index. She therefore weighed more heavily the results of the Company's updated two-growth DCF analysis in making her return-on-equity recommendation.

Finally, she recommended that the Commission accept an adjustment for flotation costs but otherwise recommended against the Company's other adjustment request. She found that the Company had not explained whether or how its proposed adjustment, triggered by the proposed true-up mechanism, would allow for meaningful, timely consideration of customers' ability to pay for a corresponding rate increase resulting from that adjustment. The ALJ also found that the Company had failed to adequately demonstrate that the mechanism is reasonable, necessary, or effective in balancing the interests of ratepayers and investors.

F. Commission Action

1. Introduction

As explained by the *Hope* and *Bluefield* decisions, the Commission must analyze the facts in the record, exercising its quasi-judicial authority, and apply its judgment, exercising its quasi-legislative authority, to determine a rate of return that appropriately balances the competing interests of ratepayers and shareholders, and which produces just and reasonable rates. Applying these principles, the Commission will set the return on equity at 9.25% for the following reasons.

2. Proxy Groups

In assessing the parties' proxy groups, the Commission recognizes that when developing a proxy group, varying sets of criteria may be reasonably applied for the purpose of identifying which other companies are acceptable proxies for Xcel. In this case, the proxy groups generally reflect reasonable criteria and consistent application of those criteria, albeit the larger and more varied the proxy group the more difficult it likely becomes to compare risk.

In particular, the Commission is not persuaded that the Company's non-price regulated proxy group includes companies with enough similarity to each other as well as to Xcel to justify its use in setting a return on equity. As the ALJ found, the risk of these companies, as individual businesses, has not been shown to be comparable to Xcel's risk

3. Analysis

a. Results of the Models

The Commission concurs with the ALJ that there is no convincing basis on this record for departing from reliance on the two-growth DCF model.

The two-growth DCF model provides a fundamentally sound framework through which to analyze the Company's relative risk in relation to comparable companies, and through which to evaluate the Company's financial integrity and ability to attract investors in light of current as well as expected market conditions. This model is based on the financial theory that the current price of a stock equals the present value of all expected future dividends in perpetuity discounted by the appropriate cost of equity (i.e., the compensation for the risks associated with owning the stock). It uses growth forecasts to model dividend growth in years one through five, and then applies a different growth rate for years six and beyond, offsetting the limitations of the constant-growth model, which assumes dividends are expected to grow at a constant rate over time. And while the two-growth DCF model is not the only useful model, its strengths underscore the limitations of other models such as CAPM, which is more subjective, and Risk Premium, which does not provide information about the returns investors require.

The Commission therefore finds that the two-growth DCF analysis provided by the Company provides a reasonable basis for setting a return in this case. No party showed that the utility proxy group criteria used by Xcel were unreasonable, that the Company's DCF analyses inaccurately reflect the results of the inputs of the model, or that the data the Company used in its DCF models misrepresented market conditions at the time the Company's studies were conducted.

The Commission also recognizes, however, that relying too heavily on a single set of results from one model could inadvertently narrow the range of reasonable returns considered, needlessly eliminating relevant data from close examination. For example, the Company's *two-growth* DCF analysis results from its *initial* filing show that the average return among the proxy group is 8.66%. After updating its data, the average return within the proxy group rose to 9.83%. Put into context, the Company's recommended return of 10.20% is still 37 basis points higher than the *updated* average of returns (and 154 basis points above the initial average of returns). Xcel's updated results incorporate data from September 2022.

By comparison, the Department's updated results corroborate this upward trend in returns. The *initial* results of the Department's four DCF analyses (constant growth, two-growth, and 10 and 20-year multi-stage) show average returns ranging between 7.77% and 9.06%. The Department's *updated* DCF analyses show average returns ranging between 8.50% and 9.94%. The Department explained sharp increases as a result of a notable decrease in utility stock prices in September and October, 2022, which increased dividend yields, coupled with a notable increase in five-year earnings growth estimates.

This trend contrasts the results of the Company's constant-growth model, which appears to underestimate the impact of market conditions, rendering it less reliable than the two-growth model for purposes of setting the return in this case. The results of the Company's initial *constant-growth* DCF analysis show an average return of 8.77%, but after updating its analysis, the average of returns *decreased* to 8.56%.

b. Changes in Market Conditions

As the data shows, the results of Xcel's two-stage DCF analysis increased by 117 basis points in approximately one year. In spite of such changes, no party modified its recommended return based on those changes, a factor that weighs in favor of applying initial and updated data to the return-on-equity analysis.[46] And while the Company declined to modify its recommended 10.20% return, it continued to emphasize the relevance of financial market conditions, both existing *and expected*, when setting the return-on-equity, noting that near the time the updated data was filed, the Federal Reserve cautioned that the longer inflation continued, the more likely that expectations of higher inflation could become entrenched. At that time, there was significant uncertainty about the direction, duration, and impact of inflation. But this sharp, upward trend in inflation has not continued into 2023; rather, inflation has declined since the highest point of inflation in June 2022, with more substantial declines in 2023.[47] The economic outlook is now considerably better than it was in 2022.

Further supporting the proposition that the proportionate impacts of inflation should be taken into account, CUB filed end-of-year 2022 stock price data showing that although stocks in general had decreased during the year by 15%, utility stocks had risen by 4%, suggesting that utility investors have not been substantially adversely affected by inflationary impacts.

Under these circumstances, it is reasonable to rely on multiple data sets from the two time periods covered by the parties' models to better estimate earnings growth. Utilizing both data

[46] XLI initially recommended a return of 9.17%, with an updated recommendation of 9.16%, but the change was not due to updated market data; XLI did not file an updated analysis.

[47] These facts are generally known and based on publicly available information; see, for example: U.S. Bureau of Labor Statistics, *CPI for All Urban Consumers, 12-Month Percent Change, All Items in U.S. City Average*, DATABASES, TABLES & CALCULATORS BY SUBJECT (last visited July 13, 2023), https://data.bls.gov/timeseries/CUUR0000SA0?output_view=pct_12mths

sets provides a more informed and comprehensive understanding of market conditions and their impacts. Notably, averaging the results of the Company's initial and updated two-growth DCF analyses produces a return of 9.25% (8.66% is the average return based on the results of the Company's initial filing, and 9.83% is the average based on the results from rebuttal testimony).

This approach also takes into consideration the Department's recommended return of 9.25%, premised largely on the theory that market analysts' use of current market earnings over-estimate long-term growth. In this case, the impact of high inflation rates in 2022, when Xcel updated its data, merits consideration of that position. Considering both Xcel's initial and updated data fairly accounts for the Department's emphasis on estimating growth as reasonably and accurately as possible. As stated above, no party changed its recommendation as the case progressed, despite discussing the underlying economic conditions, which suggests that the parties—including Xcel—continued to find their initial analyses reasonably reliable.

Taking into account the results of multiple data sets reasonably balances the risk to both ratepayers and the Company by avoiding over-compensating for high inflation while simultaneously protecting the Company's financial integrity.

Further, setting rates in an MYRP means that rates will continue for at least three years—under Minn. Stat. § 21B.16, subd. 19, rates for the third year will be in effect until the Company files another rate case. The Commission is not persuaded that it would be reasonable to rely exclusively on data that, based on this record, appears to be significantly impacted by a period of peak inflation, for a duration of at least three years and possibly longer.

c. Check on Reasonableness

While the results of other models or analyses are less persuasive, they do provide a check on reasonableness. The Department's recommended return-on-equity of 9.25%, while derived from a different DCF model than the Company's, is consistent with the average results of the Company's DCF models. The average of XLI's two-growth DCF analysis (8.55%), based on initial data not subsequently updated, corroborates the reasonableness of the average of the Company's initial two-growth DCF analysis results (8.66%). The Company itself represented 9.30% as a reasonably updated average of its DCF analyses (both constant growth and two-growth).

Although CUB's approach to financial modeling is rooted in a philosophically different approach to setting utility returns, the Commission appreciates CUB's recommendation to meaningfully consider the impacts of high inflation on both the utility *and consumers* when setting the return.

The Commission is also unpersuaded by Xcel's claims that a 9.25% return is insufficient to enable the Company to attract capital at reasonable rates, maintain its credit rating and financial integrity, and provide returns commensurate with those earned on other investments with equivalent risks. The Commission also finds value in XLI's arguments that Xcel's investors face lower levels of risk because of the regulatory tools used by the Company, which include multiyear rate plans and riders; the Department noted that Xcel's financial performance has been successful with a return on equity of 9.06%. While Xcel correctly notes that the stock price and dividends are those of its parent company, and not its regulated Minnesota utility, it is clear that the Minnesota utility contributes to the success of the parent company. The fact that its enterprise has been financially strong while earning a return of 9.06% is an indication, in light of the facts on this record, that increasing its rate of return by nearly 20 basis points, to 9.25%, will not jeopardize Xcel's financial integrity.

Finally, no party recommended a return higher than 9.25% other than the Company.

For all these reasons, the Commission will set the Company's return on equity at 9.25%, including flotation costs.

4. Adjustments

The Commission concurs with the ALJ that no further adjustments are warranted. As she explained, the Company did not substantiate how its proposed adjustment mechanism in each year of the rate case would be calculated or implemented and did not adequately quantify how it might affect ratepayers.

Furthermore, the Company agreed to the Department's recommended adjustments to the Company's cost of short-term and long-term debt to reflect increases in interest rates, which thereby increases the Company's overall rate of return.

The Company has not established that other adjustments are necessary to align the Company's return with its ability to attract capital to finance investments at reasonable rates.

XXXI. Financial Capital Structure and Overall Rate of Return

The final capital structure and overall rate of return resulting from the decisions made herein are set forth below.

Table 9
2022 Capital Structure and Overall Rate of Return

Type of Capital	Capital Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	46.89%	4.19%	1.96%
Short-Term Debt	0.61%	3.73%	0.02%
Common Equity	52.50%	9.25%	4.86%
Total	100.00%		6.84%

Table 10
2023 Capital Structure and Overall Rate of Return

Type of Capital	Capital Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	46.50%	4.33%	2.01%
Short-Term Debt	1.00%	3.50%	0.04%
Common Equity	52.50%	9.25%	4.86%
Total	100.00%		6.90%

Table 11
2024 Capital Structure and Overall Rate of Return

Type of Capital	Capital Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	47.08%	4.40%	2.07%
Short-Term Debt	0.42%	4.17%	0.02%
Common Equity	52.50%	9.25%	4.86%
Total	100.00%		6.95%

CLASS COST-OF-SERVICE STUDY

XXXII. Cost of Service and Rate Design

A. Introduction

The preceding sections have sought to quantify the costs that a prudently managed utility serving Xcel's service area would bear throughout the 2022 test year and 2023 and 2024 plan years--in other words, Xcel's *revenue requirement*. The following sections will address how Xcel may recover those costs, and especially how it may recover costs from its ratepayers in Minnesota--in other words, Xcel's *rate design*. As discussed further below, one consideration when designing rates is how the cost of providing service differs from one ratepayer to another.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different types of customers, and will incur many costs that benefit multiple types of customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analyses by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

To aid this analysis, the Commission directs utilities to conduct a class cost-of-service study (CCOSS). Minn. R. 7825.4300(C) directs a utility to file a cost-of-service study by customer class of service, geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class, area, or category, identifying the procedures and underlying rationale for cost and revenue allocations.

For purposes of its class cost-of-service study, Xcel identified seven retail customer classes: Residential, Outdoor Lighting, and five categories of commercial/industrial customers.

B. Steps for Conducting a Class Cost-of-Service Study

A class cost-of-service study seeks to identify, as accurately as possible, each customer class's causal responsibility for each cost the utility incurred in providing service. *The Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissioners (NARUC Manual) recommends conducting a CCOSS in three steps. First, the manual recommends grouping costs according to their function. Second, the manual recommends classifying costs based on how they are incurred. Third, the manual recommends allocating costs to the various customer classes.[48]

Functionalization: For purposes of an electric utility CCOSS, the typical functions are generation/production of electricity, transmission, and distribution.

Generation refers to the cost of plant used to generate electricity.

Transmission refers to assets that permit electricity to move efficiently at high voltage from where the electricity is generated to the distribution network.

The distribution system carries electricity from the transmission system to a customer's location. Utilities distinguish between the primary distribution system and the secondary distribution system. In the primary distribution system, electricity travels from the high-voltage transmission system to substations, which reduce the voltage and distribute it via lines and poles to the neighborhoods of retail customers. Some large industrial customers purchase power at primary distribution voltages, but otherwise this electricity flows to the secondary distribution system, where distribution transformers again reduce the voltage, allowing it to be distributed via lines and poles to customer premises.

Classification: The cost of a function may be classified as related to customers, energy, demand (or capacity), or a combination of the three.

Customer-related costs increase as the number of customers increases. Energy-related costs increase as a customer's consumption of energy increases. Demand-related costs increase as the rate at which the customer consumes energy increases, especially during periods of peak demand. Demand-related costs become relevant because a utility must design its system to, at a minimum, meet the forecasted simultaneous demand of all its customers plus maintain a specified amount of additional generating capacity (known as a reserve margin) to address unanticipated levels of demand or equipment failures. MISO establishes criteria for determining the amount of capacity each generator contributes to the regional power grid, and the amount of reserve margin required for each load-serving entity—that is, each retail utility—within its grid.

For commercial and industrial customers with a demand meter, Xcel calculates a charge for the cost of the facilities required to serve that customer's peak usage (a "demand charge"), as well as a separate charge for the amount of energy consumed. For customers in the other customer classes, the costs of energy and demand are recovered through a charge solely on energy.

Allocation: The various costs are then allocated to each customer class using a formal called an allocator.

Choices about classification and allocation strongly influence the results of a CCOSS. The choice of allocator can have important rate consequences. For example, residential customers tend to have a lower load-factor than industrial customers—that is, energy consumption by residential customers tends to fluctuate more than energy consumption by industrial customers.

[48] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, at 18-23 (January 1992), attached to Collins Direct.

As a result, classifying a given cost based on energy will tend shift more responsibility toward industrial customers, whereas classifying that cost based on demand will tend to shift cost responsibility toward residential customers.

C. Multiyear Rate Plan

Because Xcel filed an MYRP, its CCOSS calculated a new estimate of costs attributable to each customer class for 2022, 2023, and 2024.

XXXIII. CCOSS-Model Selection

In addition to Xcel, the OAG and XLI filed CCOSS models. As a general proposition, the ALJ concluded that each party's CCOSS modelling provided useful information. Noting that the Commission has in recent years "taken a holistic approach and indicated a preference for reviewing multiple methods," the ALJ concluded that each of the CCOSS models had useful attributes, and that all should be considered.[49]

The Commission has previously found that "[n]o single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data."[50] The Commission retains the view that each CCOSS model provides useful information and will therefore decline to adopt any one model for all purposes.

XXXIV. CCOSS—Classifying and Allocating Fixed Production Plant

A. Issue

Fixed production plant refers to the capital cost of generators and related equipment.

No party disputes that the cost Xcel bears for production plant is driven by the level of demand for electricity as well as energy. The cost reflects demand because, as previously noted, Xcel must design its system to be able to meet the anticipated peak level of demand. The parties also agree that the cost reflects Xcel's energy costs—although the parties disagree about why.

B. Positions of the Parties

1. The Department, the OAG, and Xcel

The Department, the OAG, and Xcel favor classifying and allocating fixed production costs using the Stratification Method—a variant of the Equivalent Peaker Method set forth in the NARUC Manual—which Xcel has employed since the 1970s. These parties argued that Xcel selected its portfolio of generators to meet its anticipated peak demand and reserve margins. But

[49] ALJ Report ¶ 829 (discussing distribution plant).

[50] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-017/GR-20-719, Findings of Fact, Conclusions, and Order (February 1, 2022) at 44.

Xcel observed that if it were to design a system solely to serve that function, it might have built its entire system out of natural gas "peaking" generators, which have the lowest capital cost per unit of generation (for example, per kilowatt or kW). But these generators also have high operating costs per unit of energy generated (for example, per kilowatt-hour or kWh). According to Xcel, the fact that electric utilities chose to rely on a variety of generators—including generators with higher capital and lower operating costs—demonstrates that utilities design their systems not only to meet peak demand, but also to reduce energy costs.

Xcel proposed allocating the energy-related costs among customer classes using its E8760 allocator. Throughout the year, each customer class's consumption of energy varies, and the cost of generating a unit of energy varies. To fairly allocate these costs among customer classes, Xcel considers both the cost of acquiring a unit of energy for each of the 8,760 hours of the year, and the amount of energy being consumed by each customer class for each hour. The Department and OAG supported this proposal.

In addition, Xcel proposed allocating capacity-related costs using the D10S allocator, which allocates costs among customer classes in proportion to each class's energy usage during the period of peak demand. The Department and the OAG supported this concept, but the OAG raised concerns about how Xcel calculated this allocator; these concerns will be addressed further below.

XLI opposed Xcel's use of the Stratification method. XLI argued that, while the Stratification method may have appropriately classified and allocated the cost of traditional generators, it fails to appropriately allocate the cost of intermittent generators—especially solar- and wind-powered generators. According to XLI, utilities primarily value these generators for their low energy cost rather than the capacity they contribute to the system. XLI argued that allocating the cost of these intermittent generators using the Stratification method, with its reliance of Xcel's D10S capacity allocator and E8760 energy allocator, causes customers with relatively high, stable energy consumption to bear a disproportionate share of capacity costs while depriving these customers of the corresponding benefit of the lower energy costs.

2. XLI

Instead, XLI favored classifying production costs using the Average and Excess – Four Coincident Peak (AED-4CP) method. Under this method, XLI estimates the cost of generating capacity Xcel requires under average circumstances and assigns those costs to customer classes in proportion to each class's average energy usage. XLI regarded the rest of Xcel's generating capacity as reflecting the cost of capacity created to meet peak demand. XLI allocated these costs among customer classes in proportion to each class's peak demand costs measured four times per year—that is, the amount of energy each class uses during four periods of peak demand, but only to the extent that this amount exceeds the class's average energy consumption.

XLI also noted that the Administrative Law Judge in Minnesota Power's then-pending rate case recommended the use of the AED-4CP method.

The OAG and Xcel opposed use of the AED-4CP method. The OAG disputed the model's relevance, arguing that a utility must design its system to meet total demand regardless of whether anyone would characterize the demand as "average" or "excess." Because this method focuses on the variability of each class's energy consumption, the OAG argued, it has the effect of minimizing the share of costs borne by the customer class with the highest energy consumption.

Xcel challenged the way XLI applied its method. Xcel noted that XLI's method allocates cost on the basis of four *coincident peaks*—that is, the extent to which each customer class consumes energy during four specific periods of peak demand on the relevant system. The NARUC Manual states that the Average & Excess method should allocate costs on the basis of *non-coincident peaks*—that is, each class's highest periods of consumption throughout the relevant test period, even if those periods do not coincide with the relevant system peaks.[51]

C. Recommendation of the Administrative Law Judge

Citing a prior Xcel rate case order, the ALJ concluded that the Stratification method is more reflective of cost-causation than the AED 4CP method because this method "appropriately reflects the fact that Xcel builds baseload plants to meet both demand and energy needs."[52]

D. Commission Action

Both proposed methods for classifying and allocating fixed production cost acknowledge the role that energy and capacity play in influencing Xcel's portfolio of generators. However, the Stratification method uses the economics of a peaker plant as the basis for distinguishing between investment motivated to procure capacity and investment motivated to procure energy. This provides a sounder rationale for distinguishing between energy-related and capacity-related costs than the distinction between average and excess energy consumption.

XLI correctly observes that Xcel is increasingly acquiring energy from solar- and wind-powered generators, which are notable for their low energy costs and low contributions to system capacity requirements. But the Commission is not persuaded that this fact alters the applicability of the Stratification method—focused on peaker generators that contribute capacity with *low* capital costs and *high* energy costs—for purposes of a CCOSS.

Finding insufficient reason to alter its prior practice, the Commission concurs with the ALJ and will retain the use of the Stratification method for classifying and allocating fixed production cost.

XXXV. CCOSS – Peak Demand (D10S) Allocator

A. Issue

As previously discussed, a CCOSS classifies certain investments as related to capacity or demand. No party disputed that these investments would be allocated among the customer

[51] *See*, for example, Jeffry Pollock Direct at 21 ("[T]he customer non-coincident peak … measures the maximum demand of each customer, irrespective of when it occurs.")

[52] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order at 64 (May 8, 2015).

classes in proportion to each class's energy consumption during periods of peak demand. But there are various methods for calculating this allocator.

Non-coincident peak demand refers to the maximum amount of energy a given customer class consumes over a specified period. *Coincident peak demand* refers the amount of energy a customer class consumes during the period of peak demand on the system. The coincident peak identifies the period when the electrical system has the least spare resources to manage additional load or a loss of capacity, so the coincident peak has often provided the basis for allocating demand-related costs.

Historically electric utilities operated independently, building their own plant to generate, transmit, and distribute electricity to their own customers. These utilities designed their system to be able to meet their customers' needs during periods of peak demand plus a reserve margin to manage unanticipated circumstances (extra demand, or an unplanned outage from a generator or transmission line).

But today many electric utilities join to create independent system operators such as MISO. MISO's wholesale energy markets permit utilities to make use of each other's facilities—provided there are sufficient resources available at that time. To ensure resource adequacy, MISO establishes the required amount of reserve capacity and allocates the responsibility for meeting this obligation among load-serving entities such as electric utilities. Finally, MISO calculates this reserve margin based on its peak demand—which may not coincide with the peak demand on any individual utility's network.[53]

As a result, MISO's coincident peak now identifies the period when the electrical system has the least spare resources to manage additional load or a loss of capacity. For this reason, the Commission ordered the utility to "base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak."[54]

In the current case, Xcel acknowledged that it did not base its D10S allocator on this basis, explaining that MISO had not published the data that would enable Xcel to comply. Xcel proposed a proxy allocator instead. The Department found this proxy satisfactory under the circumstances; the OAG did not.

B. Positions of the Parties

1. Xcel, the Department, and XLI

When Xcel filed this rate case in October 2021, Xcel could not know what the MISO peak hour would be in the 2022, 2023, or 2024 test years. Instead, Xcel analyzed data from MISO's system

[53] MISO collects data in different zones for different purposes. MISO's Local Resource Zone 1 encompasses most of Minnesota, all of North Dakota, and portions of Montana, South Dakota, and Wisconsin.

[54] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 46 (June 12, 2017).

peak in the relevant planning zone for the past 12 years to forecast the amount of energy each customer class would consume for the six highest peak hours on Xcel's system. According to Xcel, this calculation would likely encompass the MISO peak hour.

The Department and XLI concluded that Xcel's D10S allocator reflects a reasonable effort to implement the Commission's requirement. The Department cautioned against pursuing a pseudoscientific precision in calculating peak demand, noting that the rate case relies on forecasted test years, forecasted planning years, and weather-normalized data.

2. The OAG

The OAG emphasized that the Commission directed Xcel to develop its demand allocator using the peak for MISO's entire system, not for one zone within the system. According to the OAG, this is appropriate because MISO establishes Xcel's resource adequacy requirements based on MISO's system peak, not the zone peak. Accordingly, the OAG calculated a revised D10S allocator based on MISO's system peak for 2016, 2020, and 2021, which it said were the most recent years for which Xcel provided hourly usage data by class.

Xcel raised concerns about the OAG's proposal, noting that it relied on data that had not been weather-normalized—that is, data that had not been adjusted to offset how each year's idiosyncratic weather would predictably alter patterns of energy consumption. But the OAG noted that its proposed allocator is scaled to the weather-normalized sales forecast for each test year.

While Xcel continued to support its own proposed allocator, the utility stated that it would not oppose a Commission order directing the utility to employ the OAG's formula prospectively—a proposal that the OAG supported as well.

C. Recommendation of the Administrative Law Judge

Because MISO did not provide the necessary data that would permit Xcel to comply with the Commission's direction for calculating its D10S allocator, the ALJ concluded that Xcel was justified in using some proxy method for creating the allocator, and that Xcel's proposed method represented a reasonable proxy. Accordingly, the ALJ supported Xcel's recommendation.

D. Commission Action

The Commission concurs that MISO has not provided the data necessary to permit Xcel to forecast the periods of peak demand on MISO's system in future years, and that Xcel was justified in developing a proxy method. That said, the Commission finds that the OAG's proxy—based on MISO's past system peaks rather than on the peaks in a single MISO zone—better reflects the Commission's instruction.

The Commission will not seek any revisions for purposes of the current case. But for Xcel's next general rate case, consistent with the suggestions of the utility and the OAG, the Commission will direct Xcel to calculate the D10S allocator based on its system peak coincident with the MISO system peak using historical data.

XXXVI. CCOSS – Classification of Joint Transmission Costs

A. Issue

Transmission assets permit electricity to move efficiently—which entails moving at high voltage—from where the electricity is generated to where it is needed. While some high-voltage lines serve a single industrial customer, most serve the electrical system in aggregate—and no party disputes that all customer classes should bear a share of these joint transmission costs. But parties disagree about how to classify these costs for purposes of allocation. Given the nature of the parties' disputes, the Commission will first discuss the classification of joint transmission costs, followed by a discussion of the allocation of these costs.

B. Positions of the Parties

1. Xcel and XLI

Citing the NARUC Manual, Xcel argued that it designs and builds its joint transmission capacity in order to be able to meet the needs of all customers during the period of maximum customer demand. Accordingly, Xcel classified these costs as demand-related. XLI supported this analysis.

2. The OAG

The OAG acknowledged that meeting peak demand is the central goal when designing transmission assets. But the OAG also argued that Xcel's transmission system, like its portfolio of generators, is also designed to provide access to lower-cost energy; accordingly, the OAG recommended classifying transmission assets as 70% demand-related and 30% energy-related.

According to the OAG, MISO characterizes 32% of Xcel's transmission lines as Multi-Value Projects. These lines are designed and justified in part for their value in providing regional reliability and access to cheaper sources of energy, forecasted to save $20 billion to $71 billion over time. The OAG also noted that other load-serving entities (that is, utilities) pay Xcel for the use of Xcel's transmission assets, and roughly 24% of those revenues are based on the energy transmitted rather than on demand factors.

While Xcel cited the NARUC Manual for the proposition that transmission assets should be classified as demand-related, the OAG also cited the manual for the proposition that the cost of transmission assets should be classified in the same manner as generation assets—which all parties agreed should be analyzed as both demand- and energy-related. The NARUC Manual states —

> After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated.[55]

[55] NARUC Manual, at 75.

In addition, the OAG cited the cost allocation manual published by the Regulatory Assistance Project (RAP Allocation Manual)[56] supporting its position.

XLI also opposed the OAG's position. XLI acknowledged that transmission assets generate some benefit by permitting greater access to generators with lower-cost energy but argued that this benefit is subordinate to the goal of meeting peak demand, and thus the Commission should classify these assets as demand-related.

That said, Xcel acknowledged that it is currently developing transmission lines for the purposes of connecting solar- and wind-powered generation to the grid to replace energy from retiring coal-powered generators. As a compromise, therefore, Xcel proposed developing a new classification method that would distinguish among the goals of maintaining resource adequacy, maintaining system reliability, and cost causation—the objectives justifying Multi-Value Projects.

C. Recommendation of the Administrative Law Judge

The ALJ adopted the OAG's analysis. While meeting peak demand remains the primary purpose for transmission assets, the ALJ concluded that the value of these assets in securing other goals—especially the goal of securing lower-cost electric energy—justifies classifying them as both demand- and energy-related.

D. Commission Action

The Commission concurs with both the OAG and the ALJ. Without minimizing the importance of designing transmission systems to meet forecasted demand, the Commission acknowledges—and no party disputes—that these assets provide additional benefits to the electric system. In particular, transmission assets permit Xcel to gain access to low-cost energy to serve its retail customers, and to deliver surplus energy to sell into the wholesale market.

Accordingly, the Commission will adopt the ALJ's proposal to classify Xcel's transmission assets as 70% demand-related and 30% energy-related.

XXXVII. CCOSS – Allocation of Transmission Costs

A. Issue

All parties concurred with classifying Xcel's transmission assets as at least partially demand-related. But the parties disagree about how to allocate the resulting demand-related costs among customer classes.

[56] Regulatory Assistance Project, *Electric Cost Allocation for a New Era*.

B. Positions of the Parties

1. Xcel, the Department, and XLI

Xcel proposed allocating demand-related transmission costs among the classes using its D10S allocator, which analyzes each class's forecasted energy consumption during the hour of MISO's peak demand during each test year. The Department and XLI concurred.

The OAG also supported allocating demand-related transmission costs among customer classes based on each class's consumption of energy during MISO's peak—but supported incorporating other demand data as well.

2. The OAG

Specifically, the OAG would consider not merely data from MISO's annual peak, but data from one peak hour during each month of the year, resulting in an allocator incorporating data from twelve peak hours (the 12 Coincident Peak allocator, or 12CP allocator). The OAG noted that, when other load-serving entities use Xcel's transmission assets, Xcel collects revenues from them based in part on demand charges that are calculated based on the entity's peak load during each month; the OAG's proposal emulates this formula.

Both Xcel and XLI opposed this proposal. They argued that a utility must design its system to meet peak annual demand (typically during the most extreme weather of summer or winter), and that it makes no sense to give equal weight to the peak annual demand and to the peak demand during months of more moderate demand (such as in the spring and fall).

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Xcel, XLI, and the OAG had articulated sound arguments for their proposals, and that the Commission would be justified in adopting either proposal.

D. Commission Action

While utilities have traditionally given exclusive focus to the annual peak demand, the growing acceptance of relying on a broader concept of peak demand is reflected in the manner in which Xcel is compensated for the use of its transmission assets, as argued by the OAG. Precisely because annual peak demand tends to occur during the summer and winter, utilities tend to take generators out of service for maintenance during the spring and fall. But this strategy results in greater system vulnerabilities during these off-peak seasons when an unplanned outage occurs due to some equipment failure. Managing these failures requires ensuring adequate transmission capacity as the grid's supply and demand change at all points of the calendar.

Accordingly, the Commission will approve allocation of demand-related transmission costs using the OAG's 12CP allocator incorporating demand from the forecasted peak hour of every month of the year.

XXXVIII. CCOSS – Classification and Allocation of Distribution Costs

A. Issue

Transmission facilities take high voltage electricity from where it is generated to a substation near where it is needed; in contrast, distribution facilities—including poles, wires, and other equipment—deliver the electricity at lower voltage from the substation to the premises of retail customers.

Distribution costs relate to the number of customers served because adding a new customer requires some incremental cost, even if that customer then never actually uses any electricity. Distribution costs also relate to demand because the utility designs the plant not merely to provide minimum connection, but to have sufficient capacity to reliably meet customers' peak needs.

B. Positions of the Parties

1. Xcel and the Department

Xcel used the Minimum System Methodology to determine the portion of distribution costs that are customer-related and the portion that are demand-related. The NARUC Manual identifies at least two ways to implement the Minimum System Methodology: the Minimum Size Method and the Zero-Intercept Method. Xcel used both.

In implementing the Minimum Size Method, Xcel estimated the minimum cost to connect all customers to a minimum distribution system covering Xcel's service area, and classified these costs as customer-related. Xcel then classified all remaining distribution costs—that is, costs related to increasing the system's capacities above the minimum level—as demand-related.

In implementing the Zero Intercept Method, Xcel conducted a statistical analysis to find out how much the cost of its distribution system increases as its capacity increases. Based on that relationship, Xcel then estimated the costs the utility would have had to incur to create a hypothetical distribution system with zero capacity. Xcel classified these costs as customer-related and classified all remaining distribution costs—costs related to increasing the system's capacities above zero—as demand-related.

Thereafter Xcel incorporated the two methods into a third method, its Hybrid Method. Xcel divided its distribution plant into functional categories, and then used the previous two classification methods to estimate the share of customer-related costs in each category. Where these two methods disagreed, Xcel would pick the smaller of the two estimates of customer-related cost. The remaining share of costs in each category would be assumed to be demand-related costs.

In support of this choice, Xcel argued that both the Minimum System Method and the Zero Intercept Method were designed to identify the cost of some minimally sized distribution plant necessary to reach all customers, and to characterize only that cost as customer-related. Xcel found both models reasonable, and reasoned that by picking the lowest allocation attributed to customer costs, Xcel could best fulfill the models' objectives.

The Department generally found this classification method to be reasonable.

2. The Suburban Rate Authority

The Suburban Rate Authority also generally supported Xcel's proposal—but acknowledged that other classification and allocation methods were reasonable, and the Commission would be justified in considering a range of methods for classifying and allocating distribution costs.

3. XLI

XLI supported use of either the Minimum System or Zero Intercept Methods, but opposed Xcel's Hybrid Method. XLI argued that the Hybrid Method—picking data from the other two methods based solely on the criterion of minimizing customer costs—was structurally biased to inflate demand costs, which would ultimately have the effect of increasing the share of costs to be recovered from commercial and industrial customers.

In addition, XLI objected to an adjustment for the minimum system load that Xcel made as part of its Zero Intercept Method.

4. The OAG

The OAG opposed using the Minimum System Methodology, citing arguments set forth in the RAP Allocation Manual. In addition, the OAG argued that Xcel had inappropriately excluded relevant data from its Zero Intercept analysis, skewing the results.

Instead, the OAG supported the Basic Customer Method and the Peak-and-Average Method. The Basic Customer Method classifies distribution plant that serves a single customer or meter as customer-related—for example, the cost of customer meters and service drop lines—because those costs obviously vary based on the number of customers. All other distribution costs are classified as demand-related.

The Peak-and-Average Method also identifies a narrow range of customer-related costs, but then identifies as energy-related the cost of building a distribution plant to meet average energy consumption, and classifies only the remaining costs—costs needed to serve customer needs that exceed the average level—as demand-related.

Citing the RAP Allocation Manual, the OAG ultimately advocated identifying the customer-related costs using the Basic Customer Method, identifying the energy-related costs using the Peak-and-Average Method, and classifying all remaining costs as demand-related. But the OAG acknowledged that the Commission would be justified in considering other methods as well.

In contrast, Xcel and XLI opposed use of the Basic Customer and Peak-and-Average Methods. They argued that the Basic Customer Method understated the customer-related share of distribution plant, and therefore failed to reflect principles of cost-causation imbedded in the methods supported by the NARUC Manual. Also, XLI argued that the OAG provided insufficient support for classifying distribution plant as energy-related, as assumed in the Peak-and-Average Method, and XLI raised technical challenges to the manner in which the OAG had applied this method. Xcel and XLI acknowledged that the OAG cited instances where these classification methods were endorsed by the staff of other states' regulatory commissions, but argued that this support was atypical.

Finally, as a procedural matter, the OAG recommended that the Commission direct Xcel to include in its next rate-case filing CCOSSs analyzing distribution costs from multiple perspectives. In the current case, the OAG asked Xcel to prepare various studies once the rate case had been filed, but this resulted in practical challenges compounded by the time constraints of the case. The OAG stated that it would be more practical for all concerned to have these analyses prepared at the beginning of the case. Xcel opposed the idea that it should have to file studies as part of its initial filing that would, in practice, contradict its own case. According to Xcel, the appropriate time for the OAG to pursue such filings is during the discovery phase of a case, and Xcel agreed to work with the OAG to produce studies at that time.

5. Just Solar Coalition

Just Solar Coalition supported classifying distribution costs using the Basic Customer Method. But like the Suburban Rate Authority and the OAG, Just Solar Coalition acknowledged that the Commission would be justified in considering a range of methods.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that each proposal had merit and recommended that the Commission consider them all. But the ALJ found insufficient reason to ask Xcel to file specific distribution studies as part of its next rate case filing, as requested by the OAG.

D. Commission Action

The classification of distribution costs produces the widest range of arguments in a CCOSS, and the Commission appreciates the critical analyses contributed by the parties. Having evaluated each of the proposals, the Commission concurs with the ALJ that considering multiple perspectives on the classification and allocation of distribution costs provides an appropriately broad perspective for creating a CCOSS. Each analysis provides the Commission with a standpoint from which to evaluate the other analyses. Therefore, consistent with the recommendation of the OAG as supported by the Suburban Rate Authority and the Just Solar Coalition, the Commission will direct Xcel to classify and allocate distribution costs using multiple methods—including at a minimum the Minimum System Method, the Basic Customer Method, and the Peak-and-Average Method.

Moreover, given the range of complexity of parties' positions regarding distribution plant, and the time constraints once a rate case has been filed, the Commission sees the wisdom of the OAG's recommendation to have Xcel prepare studies from various perspectives when it files its next rate case. Accordingly the Commission will direct Xcel to file multiple CCOSSs classifying and allocating distribution system costs, including the following:

- A study using the Minimum System Method.
- A study using the Basic Customer Method to identify customer-related costs and classifying the remainder as demand-related costs.

- A study using the Basic Customer Method to identify customer-related costs and using the Peak-and-Average Method to identify both demand- and energy-related costs.

While Xcel will have to prepare these studies at the Commission's direction, the Company will be free to explain why it believes one method or the other should receive more weight in a future rate proceeding

XXXIX. General Allocator

A. Issue

A utility will incur some costs for the benefit of its entire operation. To determine the share of these costs to be recovered from each of its operations, Xcel has developed its General Allocator.

Xcel typically calculates this allocator by giving equal weight to total assets, revenues, and number of employees associated with each of its operations. But in a previous case, this Commission directed Xcel to use a different allocator based in equal measure on total assets, revenues, and employment hours based on full-time equivalent (FTE) employment.[57] For this component of the allocator, Xcel identifies all the FTEs expended directly on Minnesota regulated operations or allocated to those operations, and divides by all the FTE hours expended on operations covered by the allocator.

The Commission's order notwithstanding, Xcel prepared its current case using its standard General Allocator calculated in part based on each operation's number of employees rather than FTEs.

B. Positions of the Parties

1. The Department

The Department opposed use of Xcel's General Allocator and disputed the claim that Xcel's allocator generated the appropriate jurisdictional allocation. To the contrary, the Department noted that the Commission ordered Xcel to use a revised allocator to remedy the problem of Xcel allocating excessive costs to Xcel's Minnesota operations and allocating insufficient costs to affiliates with no assigned staff.

The Department acknowledged that the Minnesota jurisdiction has a higher staffing level than Xcel's other jurisdictions but argued that the Commission's General Allocator appropriately accounts for those costs.

In sum, the Department recommended that the Commission retain the use of its General Allocator based in part on full-time equivalent hours, and therefore reduce Xcel's reported revenue requirement by $5.900 million for 2022, $6.241 million for 2023, and $6.613 million for 2024.

[57] *In the Matter of Northern States Power Company's Cost Allocation Procedures and General Allocator*, Docket No. E,G-002/AI-10-690, Order Requiring Change in General Allocator and Requiring Filings (March 15, 2011) (2011 Order); Erratum Notice (March 25, 2011).

2. Xcel

Xcel offered various arguments in support of its General Allocator.

First and foremost, Xcel asserted that using its General Allocator results in the Minnesota jurisdiction bearing its fair share of Xcel's costs, while using the Minnesota-specific allocator has resulted in Minnesota's operations failing to bear its fair share of costs. Second, while Xcel acknowledged that using its allocator increased the costs recovered from the Minnesota jurisdiction, the allocator reduced Minnesota's share of the cost of certain corporate officers.

Third, Xcel argued that calculating an allocator based on each operation's number of employees results in a more stable allocator than relying on the number of FTEs—a number that fluctuates as projects come and go. Fourth, Xcel argued that reliance on FTE hours overstates the labor costs of subsidiaries for whom an employee provides occasional services and understates the labor costs of the subsidiary with the employee on its payroll. Finally, Xcel argued that calculating and applying a different allocator for its Minnesota operations than for the rest of its operations was administratively cumbersome and could result in Xcel failing to recover some of its prudently incurred costs.

C. Recommendation of the Administrative Law Judge

Noting that the Commission had previously addressed the issue of how to calculate an appropriate general allocator, the ALJ concluded that Xcel had failed to demonstrate that the Commission's concerns were no longer relevant, that Xcel's preferred allocator remedied the problems the Commission had identified, or that Xcel's preferred allocator would promote just and reasonable rates in Minnesota. The ALJ confirmed that using a general allocator calculated on the basis of FTEs would allocate less cost to the Minnesota jurisdiction than using Xcel's preferred allocator, but the ALJ did not find this fact relevant to the question of identifying the more appropriate allocator.

In conclusion, the ALJ supported the Department's recommendation to continue using a general allocator calculated on the basis of FTEs in lieu of employee headcount, and to reduce Xcel's revenue requirement accordingly.

D. Commission Action

In ordering Xcel to calculate its general service allocator based on FTEs in lieu of labor headcount, the Commission held as follows:

> First, the labor component of the general allocator is designed in a way that results in no labor-related costs being allocated to unregulated subsidiaries that do not have their own payrolls. This is unreasonable on its face since no business can have labor costs of zero. Similarly, allocating the full costs of each employee to the subsidiary on whose payroll he or she appears overstates the labor costs of that subsidiary and understates the labor costs of any other

> subsidiary for whose benefit the employee occasionally performs services.[58]

Xcel has provided no evidence that persuades the Commission that these rationales no longer apply. As a result, the Commission will continue to direct Xcel to use a general allocator based in part on full-time equivalent employment. For this reason, the Commission will adopt the Department's position and direct Xcel to make the appropriate adjustments to Xcel's revenue requirement for test years 2022, 2023, and 2024.

XL. Interchange Agreement Allocators

A. Issue

Among the wholly owned subsidiaries of Xcel Energy Inc. are Northern States Power Company, a Minnesota corporation organized under the laws of the State of Minnesota (NSPM), and Northern States Power Company, the Wisconsin corporation (NSPW). These two entities are legally distinct and own distinct assets separated at the state Minnesota/Wisconsin boundary. Yet Xcel stated that the two entities operate as a single integrated electric generation and transmission system and a single electrical "local balancing authority area" serving customers in both states.

An interchange agreement sets forth principles for allocating costs and revenues between these entities—for example, revenues from transmission services or off-system wholesale sales. Xcel stated that it prepared its current rate case in accordance with this agreement and budgeted information for the 2022-2024 test years, just as it had in prior rate cases.

Each operating company bills the other for its share of the joint costs, using energy requirements as the basis for sharing variable costs and peak demand as the basis for sharing capital and other fixed costs.

B. Positions of the Parties

1. The Department

Based on Xcel's responses to the Department's discovery requests, the Department learned that Xcel had filed—and FERC approved—a new interchange agreement with revised demand allocators for 2022.[59] This change resulted in a $149,983 increase in Minnesota's revenue and a $1,332,358 decrease to Minnesota's generation and transmission expense in 2022. The Department argued for making these changes in Xcel's 2022 financial data for the current rate case. Moreover, the Department argued for carrying this same adjustment into the future as a known and measurable change to Xcel's forecasted allocators.

[58] *Id.*, 2011 Order, at 1-2 (citing Findings of Fact, Conclusions of Law, and Order, at 20).

[59] See FERC Docket No. ER22-1234 (May 3, 2022).

2. Xcel

In response to the Department's recommendations, Xcel agreed to using the revised demand allocations for 2022 that the utility had filed with FERC. But otherwise Xcel opposed the Department's proposed revisions and continued to recommend using the original demand allocator for later years, and recommended using the original forecast energy allocators for 2022 through 2024. Xcel argued that a change of a few variables in a multi-faceted interchange agreement did not justify altering all the forecasted allocations for years into the future. Xcel filed revised allocators annually and, according to the utility, these revisions provide no basis to expect identical revisions in the future.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with Xcel's initial recommendations. According to the ALJ, the best available evidence revealed that Xcel made good-faith estimates of its interexchange allocators when it filed its rate case, and had made good-faith revisions by the time it filed with FERC. The fact that the subsequent filing differed from an earlier one provided an insufficient basis to justify modifying the interchange agreement's forecasted cost and revenue allocations for purposes of the rate case.

D. Commission Action

The Commission concurs with the Department. No party faults Xcel for the fact that it revised its forecasted demand allocator over time. Nevertheless, the utility bears the burden of proof to demonstrate the reasonableness of its rate proposals. Clearly utilities rely on forecasts when actual data is unknowable. Still, the Department's argument is reasonable and based on the most contemporary evidence in the record.

Xcel makes a plausible argument that the Department's proposed revisions fail to reflect the many changes that occur when revising allocators. The Department states that it recommended revising the demand allocator because, in response to a discovery request, Xcel provided data justifying that revision. Perhaps Xcel could have provided other data justifying an offsetting adjustment—but that did not occur. The Department cannot be faulted for acting on the basis of the record before it.

Xcel bears the burden of proof to demonstrate the reasonableness of its proposals. The record before the Commission does not demonstrate that Xcel's proposal is superior to the Department's. Therefore the Commission will adopt the Department's filed position and direct Xcel to do the following:

- Use the actual 2022 demand allocator for the interchange agreement as approved by FERC, rather than the 2022 demand allocator as filed in this rate case, thereby increasing Minnesota jurisdictional revenue for generation and transmission by $149,983 and reducing Minnesota jurisdictional costs by $1,332,358.

- Use the updated 2022 allocators in 2023 and 2024 as well.

XLI. Allocation of the Cost of Community Solar Gardens

A. Issue

Under Minn. Stat. § 216B.1641, a community solar garden refers to an array of photovoltaic cells (solar panels) that generate electricity to sell to the local utility, where the facility is partially financed by ratepayers who elect to subscribe to the garden in return for receiving bill credits in proportion to the amount of electricity generated and the size of their subscriptions. Because solar gardens limit their subscriptions, any given ratepayer may no longer be able to find a garden still accepting subscriptions. During the Commission hearings on this case, the issue arose regarding how Xcel recovers the program's costs.

While the credits can reduce bills for solar garden subscribers, some of the program's costs are recovered from non-subscribing customers. Xcel recovers the cost of its community solar garden program in the same manner that it recovers fuel costs—that is, through a "fuel clause," a special rate that can adjust outside the context of a rate case as costs change. In 2019 utilities revised how they implement their fuel clauses and began filing "lessons learned" reports on their experience with the new policies.

Xcel estimated that an average bill for a Minnesota ratepayer includes about $10 per month to finance Xcel's community solar garden program.[60] Commercial and industrial customers have subscribed for most of the program's output, and thus received most of the bill credits. When considering how to allocate a program's costs among customer classes, the Commission may consider whether the program bestows benefits disproportionately to some classes rather than others.

Moreover, the Legislature recently adopted a new statute stating —

> The cost of a subscriber's community solar garden subscription must not exceed the value of the subscriber's community solar garden bill credit. For a LMI [low- to moderate-income] subscriber, the cost of the community solar garden subscription must not exceed 90 percent of the LMI subscriber's community solar garden bill credit and must not include any fees at the time the subscription is executed.[61]

This statutory change may require changes in how Xcel finances its community solar gardens.

B. Commission Action

To explore opportunities to better align program costs with program participants, and potentially to address new statutory requirements, the Commission will direct Xcel to file a proposal for an alternative class allocation methodology for recovering the cost of community solar gardens.

[60] This docket, transcript of oral argument (May 23, 2023) at 63.

[61] See Laws 2023, Chapter 60, Article 12, Section 13, adopting Minn. Stat. § 216B.1641, subd. 10(b).

Xcel shall file this proposal in the Commission's docket established to evaluate the fuel clause adjustment,[62] as part of its "lessons learned" report. The Commission intends to take up the issue again by February 1, 2024.

RATE DESIGN

XLII. Revenue Apportionment

A. Introduction

After establishing a utility's revenue requirement, the Commission designs rates that will provide the utility with a reasonable opportunity to recover those costs. The first step is to determine the share of Xcel's revenue requirement to be recovered from each class of customers, a process referred to as revenue apportionment.

In apportioning the utility's revenue requirement, the Commission considers the utility's cost of serving each customer class based on the results of the CCOSS methods discussed above. The Commission also considers a number of non-cost concerns such as: equity, justice, and reasonableness; the avoidance of discrimination, unreasonable preference, and unreasonable prejudice; continuity with prior rates to avoid rate shock; revenue stability; economic efficiency; encouragement of energy conservation; customers' ability to pay; and ease of understanding and administration.[63]

B. Positions of the Parties

Xcel, the Department, OAG and XLI proposed revenue apportionments based on the results of the parties' preferred CCOSS method or combination of methods. Xcel was the only party who recommended adjusting the apportionment each year of the multiyear rate plan (MYRP), while the other parties recommended maintaining the same apportionment throughout the MYRP.

The four proposed revenue apportionments for 2022, along with the Company's current revenue apportionment, are displayed in the table below:

[62] *In the Matter of an Investigation into the Appropriateness of Electric Energy Cost Adjustments*, Docket No. E-999/CI-03-802.

[63] Minn. Stat. §§ 216B.01, .03, .2401; 216C.05; 216B.16, subd. 15.

Table 12 Proposed Revenue Apportionment for 2022					
	Current	**Proposed**			
		Xcel	**Department**	**OAG**	**XLI**
Residential	39.01%	39.29%	39.29%	37.51%	40.97%
C&I Non-Demand	3.37%	3.31%	3.31%	3.29%	3.14%
C&I Demand	56.82%	56.55%	56.55%	58.32%	54.93%
Lighting	0.79%	0.86%	0.86%	0.87%	0.96%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

1. Xcel

Xcel proposed a revenue apportionment that would move all classes 50% closer to cost each year of the MYRP, based on the results of its Hybrid CCOSS. Xcel argued that movement towards cost is important because cost-based rates are equitable, stabilize utility earnings, and provide economically efficient and appropriate usage incentives.

Xcel argued that the other parties' proposed revenue apportionments did not strike a reasonable balance between setting rates at cost and moderating rate increases. Xcel disagreed with the Department that adjusting the apportionment to move 50% closer to cost each year of the MYRP was inconsistent with Commission precedent. Rather, Xcel urged the Commission to take advantage of the opportunity presented by the MYRP to move rates closer to cost modestly and gradually throughout the duration of the MYRP.

2. The Department

The Department agreed with Xcel that moving classes 50% closer to cost was a reasonable approach for the Company's revenue apportionment. But the Department recommended maintaining Xcel's proposed 2022 revenue apportionment until Xcel's next rate case, rather than adjusting the apportionment in 2023 and 2024 as recommended by Xcel.

The Department argued that its proposed apportionment better balances the tension between the economic efficiency of cost-based rates and the potential for rate shock if rates increase too quickly. The Department explained that Xcel's Hybrid method CCOSS overestimates the cost impact of the Residential class while the Basic Customer method underestimates the impact, so the Department's Residential class apportionment represents a measured approach that falls in between the results of these methods.

3. OAG

OAG noted that all CCOSS models are subjective and require simplifying assumptions, and the Commission has historically relied on multiple CCOSS to inform its revenue-apportionment decisions. OAG argued that its CCOSSs reflect reasonable assumptions regarding the causation of production, transmission, and distribution costs.

OAG calculated rate increases based on the magnitude of the difference between the amount a class is currently paying and the cost-share patterns identified in the CCOSS, while moderating increases to avoid rate shock. OAG's analysis showed that the Small C&I class is consistently contributing significantly more than its share of costs and so should receive the smallest rate increases, while the Lighting class is consistently contributing significantly less than its share of costs and so should receive the largest rate increase but moderated to avoid rate shock. Furthermore, OAG determined the Residential class should receive a smaller-than-average increase and the Large C&I class should receive a larger-than-average increase because those classes are currently each contributing more and less than their cost of service, respectively.

4. XLI

XLI argued that C&I customers on Xcel's system have consistently subsidized other classes, which has serious implications for the competitiveness of C&I customers and their ability to remain viable in Minnesota, nationally, and internationally. XLI argued that these issues can be addressed by moving C&I customers to cost, and that eliminating existing interclass subsidies on the Company's system will benefit the Company, C&I customers, and other customers by promoting efficiency, stability, and conservation while also providing just and reasonable rates to all customer classes.

XLI maintained that Xcel's proposed revenue allocation will not meaningfully eliminate the interclass subsidies and does not account for past increases and market conditions facing C&I customers. XLI maintained that the Company's proposal reduces interclass subsidies by less than 20%, with Residential customers moving only 14% closer to cost and C&I Demand customers moving only 17% closer to cost. XLI instead urged the Commission to adopt its proposed revenue allocation that sets the revenue allocation at the cost of service as determined by XLI's CCOSS.

5. ECC

ECC noted that at the beginning of Xcel's rate case, the Commission found that exigent circumstances caused by the COVID-19 pandemic justified lowering the interim-rate increase for Residential customers from 9.7% to 6.4%. ECC argued that the economic hardships endured by Xcel's ratepayers persist, particularly due to rising inflation and the end of the moratorium on utility disconnections. Due to these circumstances, ECC argued that the Commission should limit the Residential rate increase to at or below the level of the current interim-rate increase.

6. Commercial Group

The Commercial Group argued that the revenue requirement should be apportioned as closely to cost as possible. The Commercial Group noted that the C&I Demand class currently pays rates that exceed the Company's cost to serve this class, and the Commission should adopt Xcel's revenue apportionment that moves rates 50% towards costs each year.

C. Recommendation of the Administrative Law Judge

The ALJ found the Department's proposed class revenue apportionment to be the most reasonable of the parties' proposals and recommended that the Commission adopt the Department's recommendation. The ALJ noted that the Department's recommendation reasonably moves customers to cost more gradually than Xcel's proposal and reasonably balances the goals of economic efficiency, competitive rates, and avoiding rate shock. The ALJ also noted that the Department's approach is consistent with prior Commission decisions to use fixed revenue apportionment.

D. Commission Action

In apportioning the revenue requirement among customer classes, the Commission strives to set rates to recover the cost of service for each class while also moderating the rate increase to avoid rate shock for customers and considering other non-cost factors. As explained in the previous section, the Commission supports the use of multiple CCOSS methods to estimate the cost of service for each class. Xcel, OAG, and the Department based their revenue-apportionment recommendations on multiple CCOSS methods, while XLI used one CCOSS.

The Commission agrees with the ALJ that the Department's recommended revenue apportionment represents the most reasonable and appropriate approach to move rates closer to cost while avoiding rate shock. Although XLI urges the Commission to more aggressively shift revenue apportionment to reflect XLI's CCOSS, the Commission finds that a measured approach reflects the range of CCOSS methods without unreasonably burdening a single class of customers. Furthermore, maintaining the same revenue apportionment for the duration of the MYRP will gradually move rates closer to cost of service. The Commission will therefore adopt the Department's proposed 2022 test year revenue apportionment for the entire MYRP.

XLIII. Residential and Small General Service Customer Charge

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be divided among customer classes, the remaining rate-design analysis addresses how revenues are collected within each customer class. One key component of rate design is the customer charge, which is a fixed monthly charge billed to each customer in the class. This charge is intended to cover the utility's fixed costs caused by each class that do not vary with the amount of energy used.

B. Positions of the Parties

1. Xcel

Xcel recommended a customer charge of $9.00 for all Residential customers, which would increase the charge by $1.00 and eliminate the incremental $2.00 fixed monthly charges for space-heating customers, customers with underground service, and customers on Residential Time-of-Day service. Xcel argued that its proposed customer charge was well below the customer-related cost-per-bill of $19.28 shown by its Hybrid CCOSS. Xcel noted that ECC agreed to support a $1.00 customer-charge increase if Xcel agreed to its low-income discount program, which Xcel did support. Xcel argued that its recommended customer charge preserved a substantial and appropriate conservation incentive balanced with accurate cost-based pricing to improve customer equity.

In response to the Department's and ALJ's recommended $6.00 customer charge, Xcel argued that lowering the customer charge was unreasonable and inconsistent with past Commission decisions that have modestly increased or maintained the customer charge. Xcel maintained that the Department's analysis relied heavily on the Basic Customer method compared with other CCOSS models, and that decreasing the customer charge would shift costs from fixed to variable energy charges and force higher usage customers to pay for more customer-related costs. Xcel also opposed the Department's and ALJ's recommended $5.00 customer charge for Residential customers in multi-family dwellings, arguing that the Company did not have a reliable way to identify these types of customers and the lower charge would severely impair the Company's ability to recover its fixed costs.

2. The Department

The Department recommended a $6.00 customer charge for all single-unit Residential customers and Small General Service customers and a $5.00 customer charge for Residential customers in multi-unit dwellings. The Department argued that a lower customer charge will incentivize energy conservation because customers can more meaningfully reduce their bills through conservation when their total bill is largely the product of usage as opposed to fixed charges. The Department explained the importance of maintaining a clear link between consumption and cost in order to encourage energy conservation, while fixed charges weaken that link. The Department further argued that Xcel's proposed sales true-up addresses the Company's concern about its ability to recover its revenue requirement, and decoupling can be paired with lower customer charges to send price signals to customers that encourage energy conservation to the maximum reasonable extent.

In support of its proposed $5.00 multi-unit dwelling customer charge, the Department argued that multi-unit dwellings impose fewer fixed costs on Xcel's system because customers in multi-unit dwellings often share secondary distribution system facilities. The Department noted that Xcel's marginal cost study showed multi-unit dwellings have 60% lower system costs than single-family dwellings. The Department urged the Commission to require Xcel to implement a multi-unit dwelling charge for the approximately 270,000 customers the Company can currently identify and develop an outreach plan to identify remaining eligible customers.

3. OAG

OAG recommended that Xcel reduce its Residential and Small General Service customer charges by $3.00 to move them closer to cost. OAG argued that the current customer charges for these classes collect more than the customer-specific cost to serve these customers because Xcel's CCOSS overclassifies costs as customer-related. OAG cited Minn. Stat. § 216B.03, which requires the Commission to set rates to encourage energy conservation and renewable energy and argued that reducing customer charges would increase the incentive for customers to conserve energy and pursue renewable generation. OAG further argued that increasing the customer charge reduces the incentive to conserve energy by lowering the value of each kilowatt-hour (kWh) saved and increasing the payback period for energy-efficient investments.

OAG noted that people with lower incomes tend to use less energy and pay a disproportionate amount of their household income toward energy costs, and fixed costs exacerbate this energy burden for low-usage customers. OAG argued that Xcel should empower low-income customers by reducing their fixed fees, thereby giving them a greater ability to control their bills by conserving energy. OAG also supported the Department's proposed multi-family dwelling customer charge as a way to help many Minnesotans, and asserted that Xcel should not wait until it can identify every possible eligible customer.

4. Just Solar Coalition

Just Solar argued that Xcel's proposed customer charge would unreasonably charge customers for costs that are not customer costs, which is contrary to Minnesota's energy policy goals encouraging adoption of energy efficiency and distributed energy resources. Just Solar recommended the Department's initial proposal of reducing by $3.00 per month the customer charge for single-family Residential and Small General Service customers and reducing the charge by $4.00 per month for customers in multi-family homes. Just Solar did not oppose the Department's updated recommendation to set the customer charge for all single-unit Residential customers and Small General Service customers at $6.00 and for Residential customers in multi-unit dwellings at $5.00.

Just Solar reiterated that Xcel's Hybrid CCOSS method overestimates customer costs by including costs related to meeting customer demand. Just Solar argued that fixed charges are regressive because they impact low-income and lower usage customers to a greater extent. Just Solar explained that lower-usage customers have flatter demand curves, which is why peak-driven costs should not be incorporated into fixed charges as they are in Xcel's Hybrid method. For the multi-family dwelling customer charge, Just Solar suggested that Xcel could rely on self-certification with verification and other methods while it obtains more robust customer data. Lastly, Just Solar recommended Xcel be required to rely on the Basic Customer method for customers charges in future rate cases.

5. ECC

ECC indicated it could agree to a $1.00 increase in the Residential customer charge if the Company agreed to ECC's proposed low-income low-usage discount program.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission adopt the Department's recommended customer charge of $6.00 for all single unit-dwelling Residential customers and Small General Service customers and $5.00 for Residential customers in multi-unit dwellings.

The ALJ reasoned that the Department's proposed customer charges are supported by the Company's Basic Customer CCOSS, and multi-unit-dwelling customers can be served at a lower fixed cost than single-unit Residential or Small General Service customers. The ALJ also noted that reducing the customer charge will reasonably incentivize energy conservation and advance other state energy policy goals, and the Company can reasonably identify a significant number of qualifying ratepayers.

D. Commission Action

Monthly customer charges are an important component of the Company's Residential and Small General Service rates by facilitating recovery of the costs caused by each customer that do not vary with the amount of energy used. However, higher fixed customer charges discourage customers from conserving energy and investing in renewable energy by reducing the impact of these efforts on the customers' bills. Customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills. The Commission notes that Minn. Stat. § 216B.03 requires the Commission to design rates to encourage energy conservation and renewable-energy use to "the maximum reasonable extent." Considering this statutory mandate and the evidence submitted by the parties, the Commission agrees with the ALJ that it is reasonable and appropriate to lower the monthly customer charge for the Residential and Small General Service classes to $6.00.

While Xcel opposes a downward shift in its customer charge, the Commission is not persuaded that higher-usage customers will likely pay for a higher portion of fixed costs as a result. The Company's Basic Customer method shows the fixed costs of this class to be in line with the Department's recommended $6.00 monthly customer charge. As the Department explained, that method classifies customer-specific distribution equipment, such as meters and services, as customer costs, because these investments are not shared among customers within a class.

In setting the customer charge in this case, alignment with the Basic Customer method is particularly important in light of the wide variety of residential customers within Xcel's service territory. Many Residential customers are in single family dwellings, but according to the Department, more than 200,000 customers live in multi-unit dwellings of various sizes. Thus, a lower Residential charge is more likely to have a greater impact on energy conservation when applied to all of Xcel's Residential customers, and this charge will continue to reflect a reasonably representative portion of the fixed costs attributable to the many different types of customers within this class. For these reasons, the Commission is persuaded that the most equitable course of action is to reduce the monthly customer charge to $6.00.

However, the Commission disagrees with the ALJ that Xcel should implement a separate monthly customer charge for Residential customers who reside in multi-family dwellings. At this time, the Company does not have a sufficiently precise and reliable way to identify which customers would be eligible for a reduced customer charge, nor has there been robust analysis of the potential cost impacts. The Commission declines to impose this change to Residential rate design without a more accurate method for implementation or understanding of the ramifications.

XLIV. Commercial & Industrial Demand Class Rate Design

A. Introduction

C&I Demand classes encompass non-residential customers besides Small General Service customers. C&I Demand customers take service under a three-part rate that includes a fixed customer charge, volumetric energy usage charge, and demand charge. The demand charge is calculated based on the maximum amount of electricity demanded at any moment during the billing period.

B. Positions of the Parties

1. Xcel

Xcel proposed the following actions related to C&I Demand rate design:

- Maintain a similar ratio between demand and energy rates to limit rate design changes
- Moderately increase interruptible service discount that generally reinstates the discount levels prior to the Federal Tax Cut and Jobs Act
- Modify certain rules for application of the Peak Controlled Services tariff by requiring customers to provide reliable contact information and changing testing requirements to provide more certainty about available load relief during MISO emergency events
- Eliminate the Annual Minimum Demand Charge to simplify and streamline the interruptible tariff for customers
- Revise the demand charge voltage discounts under the C&I Demand tariff based on current cost levels and revise the energy charge voltage discounts for the proposed level of base energy and fuel charges
- Eliminate the Real-Time Pricing tariff and add a discretionary discount to the Business Incentive and Sustainability Rider, discussed further in subsequent sections.

2. The Department

The Department argued that Xcel should develop rates for its C&I Demand classes using the same rate design principles and CCOSS results that are applicable to other classes, but the Company failed to submit evidence-based rate proposals for the C&I Demand classes. The Department recommended that Xcel be required to produce analysis of its C&I Demand rate design proposals in Docket No. E-002/M-20-86. The Department explained that that proceeding is already focused on advanced rate design and would allow stakeholders to more substantively engage with Xcel on evidence-based commercial and industrial rates.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with the Department that Xcel's C&I Demand rates should be evidence-based and therefore recommended that the Commission adopt the Department's recommendation to require Xcel to work with stakeholders and address C&I fixed customer charges, demand rates and demand-related costs, seasonal costs and rates, other demand response and distributed-energy resource initiatives in Docket No. E-002/M-20-86.

D. Commission Action

The Commission agrees with the Department and the ALJ that the Company's C&I Demand rates should be evidence-based and developed using the same rate-design principles and CCOSS results that apply to other customer classes. The Commission will therefore direct Xcel to work with stakeholders in Docket No. E-002/M-20-86 to address C&I fixed customer charges, demand rates, demand-related costs, seasonal costs and rates, and other demand response and distributed-energy resource initiatives.

XLV. Real-Time Pricing Service Tariff Elimination

A. Introduction

Xcel has described its Real-Time Pricing tariff as a complicated time-of-use rate design with pre-established pricing as opposed to a pure real-time pricing design based on market conditions. Xcel proposed to eliminate this rate due to lack of customer interest.

B. Positions of the Parties

1. Xcel

Xcel proposed to eliminate the Real-Time Pricing rate because it had never attracted more than two customers at the same time over the nearly 20 years the rate has been in effect. Xcel posited that the lack of customer interest could be due to the complexity of the rate. Xcel noted that there is currently only one customer with three accounts taking service on this rate, and this customer was informed prior to taking service in 2018 that the Company planned to propose eliminating the rate in its next rate case. Xcel suggested that other rates such as the new three-period TOU rate would likely be more attractive and beneficial to customers.

2. The Department

The Department opposed elimination of the Real-Time Pricing Service tariff, arguing that the Company currently lacks other similar, permanent offerings and that Xcel is currently deploying advanced meters and engaged in advanced rate discussions with stakeholders in other proceedings. The Department maintained that Xcel's experience with the real-time pricing rates may inform these other rate designs.[64]

C. Recommendation of the Administrative Law Judge

The ALJ agreed with Xcel that the Department's concerns should not stop the Company from eliminating the rate offering. The ALJ reasoned that other rate offerings could be more attractive to more customers, and the potential informational value of the Real-Time Pricing Service tariff rate is not significant enough to justify requiring Xcel to continue offering the rate.

D. Commission Action

The Commission agrees with the ALJ that Xcel's proposal to eliminate the underutilized Real-Time Pricing Service tariff is reasonable and should be approved. However, the Commission recognizes that, when properly designed, real-time pricing has the potential to meaningfully incentivize demand response for sophisticated customers who can manage the risk of wholesale

[64] In its Exceptions to the ALJ Report, the Department indicated that it did not contest the ALJ's recommendation in an effort to limit the number of issues before the Commission.

electricity prices. The Commission will therefore require Xcel to work with stakeholders to develop a new real-time pricing offering.

XLVI. Business Incentive and Sustainability Rider Discretionary Discount

A. Introduction

The Business Incentive and Sustainability (BIS) Rider tariff provides an economic-development incentive to existing demand-metered C&I customers with new or additional load of 350 kW or greater.

Xcel proposed to add a five-year discretionary 50% discount to the off-peak base energy rate, applicable only to incremental loads of more than 5 MW with a minimum load factor of 70%. Xcel indicated that this was designed to attract primarily data-center customers. Xcel would file with the Commission any agreements with prospective customers, and those agreements would take effect after 30 days unless an objection was raised, a process referred to as a negative check-off.

B. Positions of the Parties

1. Xcel

Xcel argued that its proposed discretionary discount is reasonable because it would appeal to higher-load customers like data centers but would benefit all customers by spreading system fixed costs more broadly. Xcel dismissed the Department's concerns by reiterating that any party could oppose a proposed customer agreement during the 30-day negative check-off period. The Company confirmed that revenues exceed cost of service even with the discounts under the BIS Rider tariff, demonstrating the incremental financial benefits all customers enjoy due to the tariff.

2. The Department

The Department did not oppose Xcel's proposed discretionary discount but argued that Xcel should have to obtain express Commission approval before any contracts with prospective data-center customers take effect. The Department argued that this approach would allow stakeholders and the Commission a greater opportunity for review and analysis to decide if the agreement is in the public interest.[65]

3. Just Solar

Just Solar argued that Xcel should demonstrate that the net present benefits of the BIS rider outweigh the net present costs and it does not have a regressive impact in order to continue offering the rider. Just Solar argued that the BIS rider raises significant distributional justice concerns because current commercial demand and all future customers will have to bear the costs of the subsidies and incremental infrastructure costs associated with the BIS rider. Just Solar also expressed concern that stakeholders would not have sufficient ability to review agreements during the negative check-off period.

[65] In its Exceptions to the ALJ Report, the Department indicated that it did not contest the ALJ's recommendation in an effort to limit the number of issues before the Commission.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve the Company's proposed BIS Rider discretionary discount. The ALJ reasoned that the 30-day negative check-off provided parties with a reasonable opportunity to review and object to a proposed agreement if the public benefit is uncertain. The ALJ also noted that even with the discounts, revenues under the BIS tariff exceed cost of service.

D. Commission Action

The Commission agrees with the ALJ that Xcel's proposed discretionary discount though the BIS rider is reasonable, and the Commission will therefore approve the BIS rider as filed by Xcel. The proposed discounts have the potential to attract large customers to Xcel's system and provide real system benefits. If there is a question as to whether an agreement is in the public interest, stakeholders can initiate Commission review by objecting within the 30-day window. The Commission believes that this approach properly balances the Company's interest in expeditiously implementing customer agreements with stakeholders' ability to protect the public interest.

XLVII. Low-Income, Low-Usage Discount

A. Introduction

ECC proposed a discount rate for low-income, low-usage customers. Under the proposal, the Company would provide a 35% discount on 300 kWh of monthly electric usage to all low-income Residential customers whose average monthly electricity consumption is 300 kWh or less. ECC recommended establishing the income-eligibility threshold at 50% of state median income, the same threshold used in Minnesota to qualify for the Low-Income Home Energy Assistance Program (LIHEAP).

ECC recommended that eligibility be established through receipt of LIHEAP, through categorical or income-based program participation, or through an income-based self-declaration. ECC estimated that out of 305,000 residential customers that consume 300 kWh or less per month, approximately 30% of those customers (roughly 92,000) would be income-eligible for the discount. ECC explained that any usage-qualified customer that receives LIHEAP would be automatically enrolled in the discount, which applies to around 20% of eligible customers. The remaining 80% of usage qualified low-income customers (nearly 74,000) would be enrolled in the discount through the self-declaration process.

Assuming 100% eligible participation, ECC estimated the annual cost of the program at $8.3 million, which would be paid for through a $0.57 monthly surcharge to non-eligible residential customers.

B. Positions of the Parties

1. ECC

ECC urged approval of its proposed low-income, low-usage discount program as a way to provide direct financial benefits to low-income customers who are least likely to benefit from other affordability or energy-efficiency programs. ECC explained that low-income customers tend to use less electricity than higher income customers, and energy efficiency measures or other usage reduction strategies may have a negligible impact on the utility bills of low-usage customers. ECC noted that Minnesota Power has been successfully implementing a similar program by conducting robust outreach to customers who have not benefited from other programs.

ECC opposed Just Solar's recommendation to remove the usage threshold to qualify for the discount. ECC argued that doing so would increase Xcel's current low-income program funding by 200%, and a flat monthly discount regardless of energy usage does not address the disparities in energy burden, disconnection rates, target arrears, nor encourage conservation.

2. Just Solar Coalition

Just Solar Coalition supported ECC's proposed program and argued that it should be expanded to provide relief to more low-income customers. Just Solar analyzed three modifications to ECC's proposal and ultimately recommended that the 35% discount be available to all low-income customers for the first 300 kWh of monthly consumption, regardless of their total monthly consumption. Just Solar argued that this would reach an additional 230,000 customers and cost non–participating customers $1.47–$2.48 per month, depending on program enrollment. Just Solar argued that its recommended modification would go further to address energy insecurity in Xcel's service territory, noting that LIHEAP can be difficult for low-income customers to access.

3. OAG

OAG supported ECC's proposed low-income, low usage discount because it would meaningfully help low-income Minnesotans at a modest cost to nonparticipating customers. OAG acknowledged that the program would not address the systemic causes of poverty and racial inequality in the state, but it would help mitigate the impact on some of Xcel's most vulnerable customers.

4. Xcel

Xcel supported implementation of the low-income, low-usage discount rate proposed by ECC. Xcel argued that the discount helps to address the housing challenges and energy burdens faced by the Company's low-income customers during a time of high inflation and ongoing instability from the COVID-19 pandemic. Xcel also noted that the program offers a practical way to address the barriers to participation that exist in energy assistance programs by leveraging enrollment in other assistance programs or through self-declaration of income. Xcel suggested that the discount provides a way to counteract the potentially regressive impacts of a uniform customer service charge, which imposes a larger percentage bill increase on low-usage customers.

Xcel opposed Just Solar's proposed expansion of the program, arguing that it would dramatically increase the cost of the program, and that Just Solar did not provide a cost estimate of the expansion.

C. Recommendation of the Administrative Law Judge

The ALJ recommended adoption of the low-income, low-usage discount as proposed by ECC, concluding that the discount provides relief to the Company's most financially at-risk customers and appropriately limits the impact of the electric rate increase. The ALJ reasoned that although addressing the undesirable effects of the 300 kWh-per-month cap is a worthwhile goal, Just Solar's proposal would add significant cost to the program. The ALJ noted that the OAG, which is statutorily responsible for representing the interests of residential and small business ratepayers, supports ECC's recommendation.

D. Commission Action

Under Minn. Stat. § 216B.16, subd.15(a), the Commission "must consider ability to pay as a factor in setting utility rates and may establish affordability programs for low-income residential ratepayers in order to ensure affordable, reliable, and continuous service to low-income utility customers." ECC's proposed low-income, low-usage discount would provide relief to Xcel's low-income customers who are less likely to benefit from existing energy-efficiency programs and has the potential to reach more customers through the self-declaration eligibility process.

Just Solar's proposed expansion of the program would not encourage conservation, and without a reliable cost estimate in the record, the Commission lacks sufficient evidence to approve that proposal.

The Commission will therefore require Xcel to implement the low-income, low-usage discount program as proposed by ECC. The program shall be available to customers the later of the effective date of final rates or October 1, 2023. The Company will be required to submit a program status update on December 1, 2023, and annually thereafter with its electric low-income annual report.

XLVIII. EV Charging Upgrade Costs

A. Introduction

When a customer adds new load that necessitates distribution system upgrades, the Company covers the cost of the upgrades up to 3.5 times the anticipated annual revenue from the sale of additional service, excluding the portion that represents recovery of fuel costs. The customer adding the load that requires upgrades is generally responsible for the remaining cost. However, Xcel has exempted Residential customers on EV rates from upgrade costs directly related to their EV load.

B. Positions of the Parties

1. Xcel

Xcel explained that it implemented the exception for EV upgrade costs in 2021 after this issue was raised as part of the Company's Annual Residential EV Report. In that docket, clean energy groups recommended that the Company waive any potential distribution-upgrade charges for customers taking service under one of the Company's Residential EV-related time-varying rates. The Company agreed to this change, and the Commission did not object. As a result, the

Company implemented this change and continues to support this policy as consistent with its current tariff and beneficial to all customers by encouraging EV adoption and off-peak charging for this new load.

Xcel opposed Just Solar's recommendation to expand this policy to all residential customers who drive EVs regardless of whether a customer takes service under one of the Company's EV rates. Xcel explained that its exemption for customers on EV rates encourages participation in off-peak charging to reduce the impact of this new load on the distribution system.

2. Just Solar Coalition

Just Solar recommended that Xcel be required to implement an alternative approach to EV-related upgrades to improve the likelihood of customers notifying the Company of their planned EV load. Just Solar suggested a study to estimate the total cost of serving typical residential customer configurations which may result in a need for a transformer or service upgrade. Just Solar argued that EV customers' upgrade costs should be waived to avoid inequality because newer, larger homes tend to be able to accommodate this new load.

3. OAG

OAG recommended that Xcel stop exempting EV owners from the cost-sharing provisions of its tariff unless and until the tariff is revised to specifically allow it, because Xcel implemented its policy without obtaining authority from the Commission. OAG argued that this exception creates a regressive subsidy in favor of EV owners who tend to be wealthier. OAG further argued that the exception undercuts the purpose of the cost-sharing tariff by unduly burdening other customers with costs they did not cause and would tend to make electricity more expensive for those who can least afford it.

OAG countered Just Solar's arguments by noting that EV owners in older homes will still tend to have higher incomes than Xcel's customers as a whole, and therefore a ratepayer-funded subsidy in favor of EV owners is likely to be regressive.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve Xcel's practice to waive the cost sharing requirement for EV-rate customers and require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff. The ALJ found that it would be reasonable to waive distribution-transformer-upgrade charges for EV-rate customers, because doing so incentivizes participation in the Company's EV-rate offerings, helps the Company shift EV charging load through EV-specific rate design, and can reduce the cost barrier for customers who wish to undertake beneficial electrification. The ALJ found that Xcel's tariff does not presently allow it to exclude EV-rate customers from the cost-sharing provision, so a tariff amendment was necessary to continue the practice.

The ALJ was unpersuaded by Just Solar's alternative upgrade-cost proposal, because Just Solar's proposal would result in inaccurate price signals to customers. The ALJ noted that Just Solar's proposal would also eliminate an incentive to enroll in an EV-specific rate. Customers with electric vehicles should be encouraged to participate in the Company's EV programs as these programs help the Company manage EV loads and allow customers to take advantage of lower off-peak rates.

D. Commission Action

As the ALJ explained, EV rates incentivize EV charging at off-peak times, which helps the Company manage EV load and provides system benefits. By waiving the cost-sharing requirement for EV-rate customers, Xcel can encourage customers with EVs to join the EV rate. On the contrary, Just Solar's proposal would not encourage adoption of EV rates and would send inaccurate price signals by imposing the same rate regardless of when EV charging occurs rather than incentivizing consumption during off-peak hours, as the EV tariff is designed to do.

The Commission agrees with the ALJ that Xcel's practice of waiving the cost-sharing requirement for EV-rate customers is reasonable, consistent with the Commission's directives on EVs, and should be approved. The Commission will therefore require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff. The Commission will also require Xcel to discuss its policy of waiving cost-sharing requirements for EV-rate customers in its Transportation Electrification Plan in order to better understand how the policy is being implemented.

XLIX. Residential Space Heating Rates

A. Introduction

In its March 2022 order approving Xcel's load-flexibility pilots, the Commission ordered Xcel to:

> review its existing electric heating rate options, including the Back-up Relief Rate Plan, to ensure that they accurately reflect the value of the additional load and additional load flexibility for customers installing an air source heat pump and maintaining an existing gas heating backup source. If existing rates do not reflect the added value of these electrified loads, the rates should be adjusted, or new rate offerings should be developed.[66]

In response to the March 2022 order, Xcel proposed that customers with heat pumps receive service on the Company's Residential space-heating rate. Xcel proposed to eliminate the incremental $2 customer charge for residential space-heating customers and increase the differential from the standard Residential winter rate from 2.815 cents per kWh to 5.42 cents per kWh. Xcel also proposed a new space heating category for Residential TOU customers.

[66] *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, Docket No. E-002/M-21-101, Order Approving Modified Load-Flexibility Pilots and Demonstration Projects, Authorizing Deferred Accounting, and Taking Other Action at 29 (March 15, 2022).

B. Positions of the Parties

1. Xcel

Xcel argued that it had complied with the Commission's directive in the March 2022 order and reasonably shown how the new Residential space-heating rate would impact annual base-rate revenues for the average Residential space-heating customer. Xcel estimated that its proposed changes would result in annual savings of approximately $159 for a typical overhead-service space-heating customer and $242 for a typical underground-service space-heating customer, with the savings for a customer with a heat pump to be approximately $133 annually on the heat pump usage alone. Xcel maintained that its proposed changes would promote equity among all customers who have electric space-heating needs so that customers on standard residential rates and customers on the space-heating rate, with average usage, pay the same annual base-rate revenue.

Xcel disagreed with the Department that its proposal should be raised in another proceeding and argued that Clean Energy Organizations call for a more granular proposal does not mean the Company did not comply with the Commission's directive.

2. Department

The Department stated that due to the complexity of the Company's proposal, further record development of the proposal is warranted. The Department also noted that other interested stakeholders who are not parties in this proceeding may have useful input that would aid record development. The Department therefore recommended that the Commission reject Xcel's proposal and direct the Company to refile it in Docket No. E-002/M-21-101.

3. Clean Energy Organizations

The Clean Energy Organizations acknowledged that Xcel's proposed space-heating rate could benefit customers by aligning on-peak pricing with the on-peak net load forecasts for the different seasons. They explained that maintaining a three-period TOU structure year-round helps avoid customer confusion and maintain price signals to shift usage away from the on-peak period throughout the year.

But the Clean Energy Organizations argued that Xcel's proposal was insufficient because it should not be limited to electric space-heating customers. They maintained that a technology-specific TOU rate is not necessary when the pricing changes it includes reasonably reflect system costs for the whole Residential class.

The Clean Energy Organizations further argued that Xcel had not shown why 5.4 cents per kWh is the appropriate reduction to on-peak and mid-peak rates in the non-summer months. They noted that the reduction is likely excessive for the mid-peak period and would result in a price signal that insufficiently encourages off-peak usage, which may cause a higher revenue shortfall that would have to be collected through other rate adjustments. They also questioned how Xcel would implement the proposed space-heating TOU rate.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission adopt the Department's recommendation to deny Xcel's residential space-heating rate without prejudice and direct Xcel to re-file its proposal in Docket No. E-002/M-21-101, to ensure there is sufficient opportunity for interested stakeholders to participate and provide adequate time for review.

D. Commission Action

The Commission agrees with the ALJ that stakeholders who may not be parties to this proceeding should have the opportunity to weigh in on Xcel's proposed space-heating rate. Accordingly, the Commission will deny Xcel's proposed changes to its Residential Space heating Tariff without prejudice and require Xcel to refile its proposal in a new docket within 90 days of the final order in this docket.

L. Residential Time-of-Use Rates

A. Introduction

Xcel Residential customers are currently able to enroll in a two-period TOU rate with an on-peak period from 9:00 a.m. to 9:00 p.m. Xcel developed and piloted an updated TOU rate from 2017–2022, but that rate is closed to new enrollment. Xcel has started a stakeholder process to develop a full Residential TOU rate.

B. Positions of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that Xcel's TOU offerings for Residential customers are currently insufficient and should be updated to reflect changing policy and energy system conditions. They emphasized the importance of meaningful price signals that encourage conservation during periods of system constraint and argued that the piloted TOU rate may disincentivize electrification of appliances.

The Clean Energy Organizations argued that Residential customers should be able to enroll in the pilot TOU rate and suggested several modifications to the pilot TOU rate structure to better reflect cost causation and achieve residential heating electrification through seasonal differentiation: 1) eliminate the on-peak period in non-summer months, 2) reduce the on-peak rate in non-summer months, or 3) use a four-season structure where spring and fall rates are symmetrical.

They proposed that the Commission require Xcel to develop a modified, optional TOU rate, to be made available on an opt-in basis for customers with advanced meters who are not already on the TOU pilot, while the Company develops a default Residential TOU tariff.

2. Xcel

Xcel argued that the Clean Energy Organizations' proposal is not reasonable, because adjusting the TOU rate downward without another adjustment to offset lost revenue could deprive Xcel of a reasonable opportunity to recover its revenue requirement. Xcel also argued that Clean Energy Organizations' proposal would not provide customers on TOU rates with appropriate price signals and could confuse customers.

At the Commission meeting, Xcel stated that it planned to submit a Residential TOU rate proposal by the end of 2023.

C. Recommendation of the Administrative Law Judge

The ALJ found that Clean Energy Organizations' proposal was not reasonable, because it would not provide appropriate price signals accounting for increased EV load and could confuse customers. The ALJ also noted that requiring Xcel to implement a proposal outside of the current TOU development process would deprive interested stakeholders of sufficient opportunity to participate or adequate time for review. The ALJ therefore recommended that the Commission reject the CEO Residential TOU proposal in this proceeding.

D. Commission Action

The Commission agrees with the ALJ that changes to Residential TOU rates should be considered in the current TOU stakeholder process to allow all interested stakeholders to participate. The Commission appreciates that Xcel has committed to filing a Residential TOU rate proposal by the end of this year, and that the Clean Energy Organizations have indicated support for this timeline. The Commission will therefore require Xcel to file a proposed permanent Residential TOU rate by December 31, 2023.

LI. Street Lighting Rate Design

A. Joint Stipulation

Following briefing and prior to the ALJ Report, Xcel and SRA filed a Joint Stipulation that resolved all rate-design issues pertaining to the Street Lighting class in this proceeding. According to the Joint Stipulation, the agreed-to rate design changes are designed to be revenue neutral within the Street Lighting class while balancing LED lighting customer rate relief attributable to LED cost savings to both overhead and underground distribution line fed LED lighting. The Joint Stipulation contains specific rate adjustments that reduce LED rates and increase non-LED rates and underground fed street lighting rates, along with informational requirements for Xcel in its next rate case.

B. Administrative Law Judge Recommendation

The ALJ found that the Joint Stipulation could be reasonable and consistent with the interests of ratepayers and the public but concluded that there had not been a reasonable opportunity for parties to review and respond to the Joint Stipulation before the issuance of the ALJ Report. The ALJ recommended that the Commission adopt the terms of the Joint Stipulation if no party objects.[67]

[67] The ALJ Report also fully analyzed the formerly-contested street-lighting issues.

C. Commission Action

The Commission appreciates the efforts of Xcel and SRA to resolve the rate-design issues related to the Street Lighting class through the Joint Stipulation. No party has objected to the Joint Stipulation, and the Commission agrees with the ALJ that approval of the Joint Stipulation is reasonable and consistent with the interests of ratepayers and the public.

The Commission will therefore approve the Joint Stipulation between Xcel and SRA, approve the structure of the rate design for street lighting as proposed by Xcel and amended by the stipulated agreement between the SRA and Xcel and recommended by the ALJ, and approve the new LED option for Directional Lighting in the Automatic Protective Lighting Service Tariff.

LII. Advanced Rate Design

A. Introduction

The Clean Energy Organizations recommended that the Commission open a docket for a single, overarching proceeding to discuss advanced rate design (ARD) for Xcel. ARD and load-management programs are currently addressed in multiple different dockets.

B. Positions of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that Xcel should maximize customer load flexibility by developing a comprehensive suite of load-management offerings and ensuring these keep up with market and policy changes. Clean Energy Organizations explained that load flexibility enables customers to match electricity usage with periods of low-cost renewable-energy generation, which reduces the cost of energy generation and supports further clean-energy deployment. Load flexibility also decreases long-term system costs by reducing demand peaks and improving system utilization, allowing utilities to avoid or defer capacity-related investments.

Clean Energy Organizations further argued load flexibility is becoming increasingly important and complex due to customer-sited energy technologies and rapidly evolving load-management technologies. Clean Energy Organizations maintained that addressing ARD and load-management initiatives across multiple dockets has hindered a clear and transparent load-flexibility strategy resulting in an inefficient use of resources, limiting stakeholders' ability to effectively participate in the development of these initiatives. Clean Energy Organizations further contended that the Company's current rate-design processes are insufficiently nimble to keep pace with a rapidly evolving power system, citing specific examples such as the Residential TOU pilot which already relies on outdated energy-price assumptions only five years after development.

Clean Energy Organizations recommended that the Commission establish an ARD proceeding to provide the following: 1) a framework for assessing load management priorities and objectives across all customer segments; 2) a process for building on existing rate designs as policy, technology, and grid economics change; and 3) opportunities for collaboration between the utility and stakeholders, including around stakeholder-driven proposals. Clean Energy Organizations suggested a number of goals and issues to be addressed in an ARD proceeding.

2. Xcel

Xcel argued that a separate ARD proceeding is not necessary and supported handling its TOU rates for residential and commercial customers in their respective dockets. Xcel recommended that if the Commission requires an ARD proceeding, any revenue impacts associated with new rates or rate structures should be addressed in the Company's next rate case.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission take no action on the Clean Energy Organization's proposal for an ARD docket, finding that Clean Energy Organizations had not shown why a separate proceeding is necessary when ongoing dockets or an alternative process could provide a forum for discussing and improving rate designs. The ALJ acknowledged that the Clean Energy Organizations had identified appealing objectives for such a proceeding, but the ALJ agreed with Xcel that the potential scope of such a proceeding was too broad and may duplicate the work of a general rate case.

D. Commission Action

The electricity system is undergoing rapid, fundamental changes due to numerous factors including increasing renewable-energy generation and customer load-management capabilities. Designing rates to take advantage of these emerging opportunities is a complex process that would benefit from a formal proceeding to develop, evaluate, and prioritize the Company's load-management offerings. A comprehensive ARD docket would also enable analysis of the extent to which these new initiatives are consistent with Minnesota's statutory goal for rates to be 5% lower than the national average, a crucial public-interest consideration that can be overlooked when programs are developed across multiple proceedings.[68]

For these reasons, the Commission will open an Advanced Rate Design docket for Xcel and direct Xcel to work with stakeholders to develop a proposed scope and process for this docket. In this docket, Xcel shall include analysis on its compliance with Minnesota's goal for rates to be 5% lower than the national average, Minn. Stat. § 216C.05, subd. 2(4), including at minimum the following issues:

- The impact of its proposed rate increase on compliance with the statutory goal;
- The impact of conservation on bills and its relevance to the statutory goal;
- Strategies that could be employed to improve compliance with the statutory goal; and
- An alternate rate increase proposal that would be in compliance with the statutory goal, and Xcel's justifications for proposing any rate increases in excess of the alternate plan.

[68] Minn. Stat. § 216C.05, subd. 2(4).

LIII. Sales True-Up

A. Introduction

As explained in Minn. Stat. § 216B.2412, decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." A sales true-up similarly allows a utility to surcharge or refund customers to the extent that actual sales differ from forecasted sales.

Xcel proposed a mechanism that would refund customers for sales revenues above its forecast and would surcharge customers if decreased sales result in lower-than-forecasted revenues. Xcel did not propose a limit on refund or surcharge amounts. Xcel modeled its proposal on its previously approved true-up methodology,[69] with modifications to 1) exclude the metered lighting category; 2) use the C&I Demand adjustment factor for interdepartmental sales; and 3) eliminate the sales-growth adjustment that has been used for the C&I class.

B. Positions of the Parties

1. Xcel

Xcel argued that decoupling mechanisms help ensure that neither customers nor the Company are financially harmed when actual sales diverge from the forecast due to pursuit of policy objectives like energy conservation and demand response. Xcel emphasized that receiving revenues at the level approved by the Commission is necessary to maintain its safe, reliable, and environmentally responsible service.

Xcel argued to exclude metered lighting from the decoupling mechanism consistent with the rest of lighting services that are effectively decoupled. Xcel explained that metered-lighting revenue, which constitutes 7% of lighting class revenue, is consistent from year to year, and excluding it would be a practical simplification of the mechanism.

Xcel explained that its modification to use the C&I Demand adjustment factor for interdepartmental sales is consistent with base rates used for interdepartmental sales. Xcel further explained its modification to eliminate the sales-growth adjustment that had been used for the C&I class, noting that this adjustment was applicable for sales true-up calculations for 2017 through 2021 to acknowledge that the Company adjusted its revenue deficiency to recognize future forecasted sales growth in the C&I class in the 2015 MYRP, but no such adjustment is made this case.

Xcel opposed a cap on surcharges, arguing that the Company's transition from existing rates to three-period TOU rates for the Residential and demand-billed classes will have unknown and potentially significant impacts, and a symmetrical decoupling mechanism similar to what the Commission has already approved was reasonable and fair for the Company and customers under these circumstances. In its Exceptions to the ALJ Report, Xcel argued that lowering the

[69] *See In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Order Approving True-Ups with Modifications and Requiring Xcel to Withdraw its Notice of Change in Rates and Interim Rate Petition (April 2, 2021).

customer charge would increase revenue volatility and increase the likelihood of hitting the surcharge cap, hindering Xcel's ability to recover its revenue requirement.

Xcel further argued that XLI's opposition to any decoupling mechanism was contrary to sound public policy and would make Xcel an outlier compared to proxy electric utilities considered in this proceeding. Xcel dismissed XLI's alternatives as unsupported by the record.

2. The Department

The Department recommended approval of Xcel's proposal subject to modifications of a 3% hard cap on customer surcharges, inclusion of the metered lighting class, and compliance reporting requirements. The Department noted that the proposal will reduce sales-related risk typically borne by investors while also decoupling energy sales and revenue, which can facilitate other energy conservation policies.

The Department explained that a 3% hard cap on customer surcharges would limit surcharges to 3% of Xcel's annual revenues and bar Xcel from recovering amounts exceeding the cap in future years. The Department argued that this hard cap more equitably distributes the risk of lower sales due to unexpected weather and economic conditions, because Xcel is simply authorized a reasonable opportunity, not a guarantee, to recover its approved revenue requirement. The Department further argued that utility investors are compensated for assuming such business risks. The Department cited the unforeseen circumstance of the COVID-19 pandemic to argue that a hard cap ensures that these types of unforeseen risks are equitably shared between customers and the Company consistent with the statutory requirement. The Department also noted that based on how the cap would have impacted past sales, a hard cap would rarely curtail surcharges. The Department referenced the 4% cap on Otter Tail Power's sales true-up and argued that Xcel's larger size and more diversified customer base makes it better positioned to share the risks of unexpected changes in sales.

The Department argued that the characteristics of the metered lighting class make it an appropriate candidate for decoupling. The Department argued that the size of the class did not impact its ability to invest in energy efficiency and some customers' use of less-efficient bulbs means that improved efficiency is attainable.

The Department opposed XLI's proposed system-wide decoupling mechanism factor because it was unsupported by the record. The Department argued that this proposal did not account for the unique circumstances of each class and would likely insulate one class from a surcharge by spreading it across all classes.

Lastly, the Department recommended compliance reporting requirements consistent with its current true-up, and that the deadline move to April so the report can incorporate Conservation Improvement Program savings from the prior year. The Department also recommended the Commission postpone implementation of any sales true-up adjustments from the current date of April 1 until June 1, so that the Commission and parties have an opportunity to review Xcel's report.

3. XLI

XLI opposed Xcel's proposal, arguing it is not associated with energy efficiency but rather a failsafe against sales forecast errors and was single-issue ratemaking. XLI argued that it would shift all sales forecasting risk away from the Company and onto ratepayers, providing the Company with a guaranteed revenue stream. XLI noted that when sales to certain classes increase or decrease, the cost to serve that class also changes. XLI argued that the sales true-up has been extremely punitive and that Xcel has not shown it will result in just and reasonable rates.

XLI proposed an alternative mechanism of refunds and surcharges based on the Company's earnings relative to its authorized return on equity. XLI also argued that if the true-up is approved, it should be applied on a system-wide rather than class-specific basis.

4. Clean Energy Organizations

The Clean Energy Organizations recommended that annual surcharges under the Company's proposed decoupling mechanism be limited to a soft cap of 3% by customer class. They explained that under a soft cap, in years that the calculated surcharges are greater than 3% of Xcel's annual revenue, the excess amount would roll over into the following year's adjustment. They touted the soft cap as a customer protection measure that would prevent an unreasonable and extreme annual rate increase. They noted that though a hard cap would limit the rate increase, the purpose of decoupling is to remove a utility's disincentive to promote energy conservation and not to limit rate increases. They argued that a 3% soft cap strikes the appropriate balance between maintaining the purpose of decoupling while providing needed customer protection.

5. OAG

OAG agreed with XLI that it would be reasonable to reject the Company's proposal, but argued that if the proposal is approved, there should be a 3% hard cap on surcharges and decoupling adjustments should be calculated class by class. OAG argued that a hard cap is fully consistent with the requirement that decoupling mitigate the impact on a utility of Minnesota's energy-savings goals because there would still be surcharges to make up for a substantial amount of any reduced sales. OAG opposed XLI's proposal for a system-wide decoupling mechanism factor because it ignores the unique characteristics of each class and could adversely impact a class that had already contributed more than its share of base revenues.

6. SRA

SRA supported Xcel's exclusion of metered lighting from its decoupling proposal, arguing that decoupling risked exposing the class to a surcharge resulting from significant changeover to LED lighting, which could disincentivize LED adoption. SRA indicated that a 3% hard cap greatly reduced the risk of an outsized cost impact to street lighting customers and would therefore not oppose a decoupling mechanism with a 3% hard cap.

7. Commercial Group

The Commercial Group opposed the proposal. The Commercial Group cited surcharges resulting from Xcel's last true-up mechanism that surcharged C&I Demand customers for lower sales without accounting for the lower cost of serving those classes because of the lower sales. The Commercial Group argued that if the proposal is adopted, the Commission should adjust Xcel's return on equity downward to compensate.

C. Recommendation of the Administrative Law Judge

The ALJ recommended approval of Xcel's sales true-up mechanism for the duration of the MYRP, subject to the 3% hard cap recommended by the Department. The ALJ reasoned that a hard cap best balances the statutory requirements for decoupling mechanisms, because it would balance the financial interests of investors and ratepayers by ensuring that financial risks of unexpected sales declines are shared. The ALJ noted that the hard cap partially addresses the concerns of XLI and the Commercial Group and rejected XLI's alternative proposals as unsupported by the record.

The ALJ noted that, while a soft cap would prevent dramatic one-year rate spikes, it would fundamentally shift the risk of lower sales onto ratepayers. The ALJ concluded that this is inconsistent with Minn. Stat. § 216B.2412, subd. 2, which requires sales decoupling mechanisms to avoid "adversely affecting utility ratepayers." It's also inconsistent with the utility regulatory framework which only ensures the Company a reasonable opportunity to recover its revenue requirement and a rate of return to compensate investors for assuming these business risks.

The ALJ agreed with the Department that the metered lighting class should be included in the sales true-up mechanism, because there are still energy efficiency opportunities among this class. The ALJ was unpersuaded by SRA's arguments as unsupported by the record.

Lastly, the ALJ recommended that the Commission adopt the Department's proposed sales true-up compliance filing requirements.

D. Commission Action

In its order approving Xcel's 2021 sales true-up recovery, the Commission explained that rates are designed based on sales forecasts for each class, but the imperfect nature of forecasts can justify a sales true-up that corrects for inaccurate sales forecasts through refunds and surcharges to account for the difference in forecasted and actual revenues.[70]

The Commission has authorized Xcel to implement previous sales true-ups, and the Commission agrees with the majority of parties and the ALJ that a sales true-up with a 3% hard cap on surcharges is warranted in this case in order to protect the Company from potential lower-than-forecasted sales revenues and protect ratepayers from excessive and unreasonable rate increases. Like decoupling, a sales true-up counteracts Xcel's disincentive to reduce energy sales through important efforts like energy conservation and demand response.

A hard cap appropriately distributes the risk of an unforeseen drop in sales between shareholders and ratepayers. Absent a hard cap, that sales risk is borne entirely by ratepayers, which is

[70] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Order Approving True-Up Adjustments at 3 (August 5, 2022).

inconsistent with the regulatory principle that ensures the Company a reasonable opportunity—not a guarantee—to recover its revenue requirement, and which provides a rate of return to compensate investors for assuming these business risks.

The Commission also agrees with the Department and the ALJ that the metered lighting class should be included in the true-up, and the Commission appreciates SRA's acceptance of this provision subject to the 3% hard cap. And the Commission finds the Department's recommended compliance requirements to be reasonable and appropriate.

For these reasons, the Commission will approve Xcel's sales true-up for the term of the MYRP, modified to establish a 3% hard cap on surcharges and to include metered lighting. The Commission will order Xcel to submit an annual compliance filing on April 1, with a June 1 sales true-up effective date, as recommended by the Department.

LIV. Other Rider Issues

A. Introduction

Riders are special cost-recovery mechanisms that allow utilities dollar-for-dollar recovery of costs directly from ratepayers outside the context of a rate case. Some riders, such as the Conservation Improvement Program (CIP) rider, the Transportation Cost Recovery (TCR) rider, and the Renewable Energy Standard (RES) rider, allow automatic recovery of eligible costs in order to encourage specific policy objectives like energy conservation and construction of transmission infrastructure and renewable energy projects.

The Fuel Clause Adjustment (FCA) rider provides quick reconciliation of fuel costs that are generally beyond a utility's control. After a thorough investigation into the FCA process, the Commission recently modified how the process works.[71] Each utility now forecasts its monthly fuel costs for the upcoming year in an annual filing and charges those forecasted rates unless the utility can show a significant unforeseen impact on those rates during the forecasted year. At the end of the forecasted year, each utility compares its forecasted rates with its actual fuel costs incurred throughout the year and refunds any overcollections or shows the prudence of costs before recovering any undercollections.

CUB proposed the following three restrictions of Xcel's use of riders going forward:

1. Revenue caps on the TCR and RES riders;

2. Limits on the Company's ability to propose new riders throughout the course of the MYRP;

3. Requiring Xcel to propose an FCA risk-sharing proposal in the Commission's FCA investigation docket and the Company's own FCA docket.

[71] *See In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, Docket No. E-999/CI-03-802, Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements (Dec. 19, 2017).

B. Positions of the Parties

1. CUB

CUB noted that Xcel is proposing to recover approximately 26% of its revenue requirement through riders, which amounts to over $3 billion over the course of the MYRP. CUB argued that Xcel's indiscriminate use of riders obscures the true financial impact of capital investments and skews the Commission's ability to comprehensively evaluate rider impacts. CUB also argued that riders increase the administrative burden for stakeholders and cause customer confusion. CUB maintained that riders should be limited to extraordinary costs that are large, volatile, and outside of a utility's control, and the costs flowing through the RES and TCR riders no longer meet those criteria, nor the original policy purposes for those riders.

CUB further argued that despite the Commission's recent reform of the FCA process, the FCA continues to disincentivize Xcel from efficiently managing its fuel costs by placing the risk of higher and more volatile fuel costs on ratepayers rather than the Company. CUB noted that multiple parties, including Xcel, proposed variations of risk-sharing mechanisms during the FCA investigation and indicated support for reevaluating those options in the future. CUB argued that while fuel costs themselves may largely be beyond utilities' control, the impact of fuel cost volatility can be lessened through resource management and transitioning away from fuel-intensive generation.

2. Xcel

Xcel opposed CUB's proposals to restrict the Company's use of riders. Xcel argued that before TCR and RES project costs can be recovered through riders, those projects have been subject to extensive review by the Commission and stakeholders for eligibility and prudency. Xcel further argued that the scope and ownership of these projects often cannot be known during a rate case, and therefore it is not possible to develop capital budgets for this work. Xcel argued that any changes to rider design or operation should be considered in rider specific dockets.

In response to CUB's proposal for an FCA risk-sharing mechanism, Xcel argued that CUB provides no evidence that the Commission's FCA reform efforts are failing to achieve their goals or that a risk-sharing mechanism is a better means of achieving those goals. Xcel also argued that it was unreasonable to engage in a reform effort on a piecemeal basis rather than through an industry-wide proceeding.

C. Recommendation of the Administrative Law Judge

The ALJ recommended denial of CUB's proposal to impose revenue caps on the TCR and RES riders. The ALJ found that CUB had not met its burden to prove the reasonableness of its proposed revenue caps, explaining that CUB had not demonstrated that its proposal is a reasonable or necessary way to incentivize Xcel to control the costs of projects eligible for rider recovery. The ALJ noted that Xcel is required to justify the expenses proposed for rider recovery and the Commission has an opportunity to review such proposals for prudence when they are filed. The ALJ further cautioned that limiting the use of the riders before the Commission has had an opportunity to consider a proposed investment could prevent investments that would serve the riders' policy objectives and benefit ratepayers and the public.

The ALJ also recommended rejecting CUB's proposal to prohibit new riders during the MYRP. The ALJ explained that prohibiting new rider proposals during the MYRP term raises more concerns that it alleviates. It would unreasonably limit the Commission's discretion to consider and approve a future, justified rider proposal. The Commission can determine whether to approve a new rider if and when one is proposed.

The ALJ recommended that the Commission adopt CUB's proposal to require the Company to propose a risk-sharing mechanism in its lessons-learned report and cross-file its proposal in its own fuel clause adjustment docket. The ALJ found that CUB's arguments and position were supported and reasonable, and that such a proposal may be contentious is not a reason to avoid addressing it while evaluating the FCA process.

D. Commission Action

The Commission agrees with the ALJ that CUB's proposals to cap the RES and TCR riders and prohibit new riders during the MYRP should be denied. The Commission is confident that the current process for reviewing and approving RES and TCR projects for rider recovery adequately protects ratepayers and helps achieve the applicable policy goals. And the Commission will continue to carefully review any proposed new riders in the future rather than prohibit the Company from proposing new riders.

The Commission disagrees with the ALJ that Xcel should be required to file an FCA risk-sharing mechanism. The current FCA process was developed after years of hard work by many stakeholders, and CUB has not sufficiently demonstrated any significant problems with the current process. The Commission declines to make utility-specific changes to a process that applies to all utilities.

ENERGY JUSTICE AND REMAINING ISSUES

LV. Energy Justice

A. Introduction

Just Solar Coalition recommended that the Commission apply the principles of Energy Justice to this rate case, stating that these tenets provide a critical lens through which the Commission should examine setting rates. The tenets of Energy Justice, as described within The Energy Justice Workbook, were developed by the Initiative for Energy Justice and comprise four constituent principles or tenets: Recognition Justice, Procedural Justice, Distributional Justice, and Restorative Justice.[72] These are defined as:

- Recognition Justice – understanding the history and context of energy decisions that have created inequitable benefits and burdens in the past and in the present. This focuses on identifying and advocating for communities that are ignored or misrepresented in energy decisions.

[72] Initiative for Energy Justice, THE ENERGY JUSTICE WORKBOOK at 9, 66–68.

- Procedural Justice – meaningful and equitable participation and representation in energy decision making.
- Distributional Justice – ensuring benefits and burdens are equitably distributed.
- Restorative Justice – facilitating healing and harmony by improving conditions within communities and providing for remediation of legacy harms.

B. Positions of the Parties

1. Just Solar Coalition

Just Solar recommended that the Commission find that setting equitable, just, and reasonable rates includes consideration of Energy Justice. Just Solar argued that Commission decisions should not only incorporate equity and Energy Justice but endeavor to remedy inequities in the provision of electrical services, particularly for low-wealth customers and Black, Indigenous, and People of Color (BIPOC) communities. Further, Just Solar argued that the inclusion of Energy Justice would facilitate a clearer determination of whether the legal burden of just and reasonable rates has been met by the Company. Just Solar argued that the tenets of Energy Justice are embedded in the multitude of factors the Commission must weigh in its determination of just and reasonable.

2. Xcel

The Company agrees with Just Solar that Energy Justice is an important issue, stating that the issue is one the Company continues to focus through a variety of efforts, such as participation in an Equity Stakeholder Advisory Group (ESAG), its development of community-focused projects (such as the Resilient Minneapolis Project), and its partnership with Native Nations.

The Company recognizes that it can continue to develop its efforts in these areas and more effectively involve BIPOC communities it serves by, in part, explicitly centering equity in its energy plans and programs. The Company, however, believes that some of Just Solar's recommendations could be counter-productive to both parties' goal of a more just energy future and recommended against adopting Just Solar's recommendation that the Commission explicitly apply Energy Justice tenets to its rate-case decisions, stating that these issues can often be more effectively solved by engaging with stakeholders on issues that directly affect them. The Company is actively working to do so in a variety of proceedings, including general rate cases.

3. Xcel Large Industrial Customers

XLI recommended against adopting the principles of Energy Justice, stating that they are irreconcilable with standard, accepted ratemaking practices. XLI proposed that the Commission find the Energy Justice tenets recommended by Just Solar are properly included in the various non-cost factors that may already be considered by the Commission when making revenue allocation determinations.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that disputes within ratemaking routinely reduce to disputes over what constitutes just and reasonable rates. The ALJ further found that the ratemaking process is a mechanism for balancing the arguments and interests of many parties, including the interests of Energy Justice, as part of determining just and reasonable rates. The ALJ, however, found that the rate case of a single utility was an inadequate forum for addressing broad societal and systemic matters raised by Just Solar. Given the Commission's ordinary legal standard, which requires it to balance competing interests to determine just and reasonable rates, the ALJ recommended that the Commission apply its ordinary legal standard in this proceeding.

D. Commission Action

The Commission recognizes the importance of Energy Justice tenets as recommended in its proceedings, including general rate cases. While the Commission must decide issues in each rate case based on the record before it in such proceedings, the Commission finds that the tenets of Energy Justice recommended by Just Solar are relevant to setting rates in this proceeding.

LVI. Term of the Multiyear Rate Plan

A. Introduction

The Company proposed a three-year term for its MYRP for forecasted test years 2022, 2023, and 2024 in compliance with Minn. Stat. § 216B.16, subd. 19, (the MYRP Statute), which provides that "the term '[MYRP]' refers to a plan establishing the rates a utility may charge for each year of the specified period of years, which cannot exceed five years." Additionally, the Company provided additional financial information, beyond the MYRP, for years 2025 and 2026 as part of its five-year capital forecasts.

B. Position of the Parties

1. CUB

CUB recommended that the Company be required to file, in its next general rate case, a five-year MYRP, or in the alternative, forecasts to study the costs and benefits of a three- and five-year MYRP. Such an analysis, CUB asserted, would evaluate the advantages and disadvantages of the proposed MYRP compared to the capital forecast and help inform the Commission's decision on whether the Company's rate design is just and reasonable.

2. Xcel Energy

Xcel opposed CUB's recommendations and argued against the requirement to file either a three-year or a five-year MYRP in its next filing and to conduct a cost/benefit analysis to compare its chosen MYRP term and its capital forecast. Xcel noted that the MYRP statute allows a filing of an MYRP term of any period up to five years and that the selection of a three-year term strikes a balance between Xcel's ability to adapt to market conditions and rate stability.

Xcel stated that this could result in an MYRP based on outdated information. Xcel also noted that IDPs change during the development process, in separate proceedings that develop discrete issues, and in annual filings that include updates to its capital forecast data.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that mandating a five-year term removes the flexibility granted in Minn. Stat. § 216B.16, subd. 19. Additionally, the ALJ stated that CUB's recommendation could discourage utilities from requesting a MYRP and concurred with Xcel that later years in the plan would not be based on the most up to date information. The ALJ concluded Xcel has demonstrated that five-year MYRPs are not required to ensure up-to-date information. She recommended that the Commission take no action on CUB's proposal.

D. Commission Action

The Commission agrees with the Administrative Law Judge and the Company that requiring a cost/benefit analysis is unnecessary to effectively scrutinize the Company's future petition and will reject CUB's recommendations to require Xcel to file a five-year MYRP in its next general rate case and will not require Xcel to file a study of the costs and benefits of a three- and five-year MYRP in its next rate case.

LVII. Corporate Governance – Dividend Policy

A. Introduction

Xcel Energy is a wholly owned subsidiary of Xcel Energy, Inc. (XEI), a holding company that holds the controlling stock of the Company. XEI, as an investor-owned utility holding company with publicly traded stock, also issues its own debt in the form of senior unsecured bonds. The Company acknowledged in its federal 10-K filing (a form required by the Securities and Exchange Commission that companies are required to file on their financial performance) an operational risk that XEI's cash requirements could result in an increase in cash dividends that the Company needs to pay to XEI. This, in turn, could result in the need to seek out alternate sources of funding.

The Office of the Attorney General (OAG) recommended that the Commission initiate an investigation or the creation of a stakeholder group to examine the Company's corporate governance and dividend policy.

B. Position of the Parties

1. OAG

The OAG argued that the current corporate structure could result in the Company transferring excessive payments to its parent XEI. The OAG noted that while XEI makes capital contributions to the Company, the contributions are hundreds of millions less than those made by the Company to XEI.

The OAG stated that the dividend payments to XEI could be better used to finance the Company's energy transition as its position would benefit from the reinvestment of capital into expanding operations and that dividend payments could limit the Company's access to needed capital.

2. Xcel

The Company argued against the OAG's recommendation, noting the importance of dividend payments to the Company's shareholders. Additionally, the Company stated that a change in the policy governing dividends, or its level of dividends, would have an adverse effect on the Company's ability to access capital markets, in turn driving up the cost of capital. The Company also noted that capital contributions are one of the tools used to maintain the Company's equity ratio as approved by the Commission and require no additional fees or interests that would otherwise impact ratepayers. The Company further noted that the current capital structure procedures and policies are reviewed by the Commission and that the OAG's recommendation would be an inefficient use of resources.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge was not convinced by the OAG's recommendation and found that the risk identified in the Company's 10-K is hypothetical and that there is a lack of record evidence to establish a likely benefit to ratepayers of further investigations. The ALJ recommended that the Commission reject the OAG's proposal to require a proceeding or stakeholder group to examine the Company's governance and dividend policy.

D. Commission Action

The Commission is not convinced by the OAG's statements concerning the risk created by the Company's structure of dividend payments to its parent XEI. The Commission agrees with the Administrative Law Judge and the Company that the risk of driving up capital costs while offering no clear corresponding benefit is unavailing, and the Commission will therefore reject the OAG's recommendation and decline to require the Company to initiate a proceeding or create a stakeholder group to examine its corporate governance and dividend policy.

LVIII. Distributed Energy Resources – Circuit Breakers, Reclosers, and Regulator Replacement Prioritization

A. Introduction

The distribution system's hosting capacity is limited in part by the many different components that make up the system. Among those components are circuit breakers, reclosers, and regulators (these devices are commonly described as earth leakage relays, or ELR). The Company's Earth Leakage Relay (ELR) programs are designed to identify and replace aging distribution equipment. The current programs do not consider hosting capacity increases as a factor in determining when equipment is replaced.

Just Solar Coalition recommended the Commission direct the Company to modify its ELR programs to include the prioritization of replacements that would increase hosting capacity.

B. Position of the Parties

1. Just Solar Coalition

Just Solar argued that the replacement of these components could help to increase the hosting capacity of the system and that currently, potential hosting capacity improvement is a factor not considered by the Company in its ELR programs. Just Solar contended that considering hosting capacity is needed to ensure the distribution system has adequate hosting capacity for DERs as the energy transition continues.

2. Xcel

The Company argued that its current ELR programs are designed to mitigate the risk of equipment failure and service interruption to customers, whereas replacement factors currently used by the company include age, condition, and the criticality of the asset to the distribution system. These factors help the Company identify equipment reaching its end-of-life that would, if they were to fail, have the greatest impact on the Company's customers. The Company explained that the purpose of ELR programs is not to increase hosting capacity, and hosting capacity is therefore not appropriate as a required factor when determining what equipment needs to be replaced by these programs.

The Company acknowledged that budgets for ELR programs are expanding but explained that the primary reason for this is the increasing age of the distribution system's assets. If the Company were required to include hosting capacity as a factor, the Company would begin replacing newer equipment before replacing older equipment, inadvertently increasing the risk of customer outages.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company effectively prioritizes asset replacement in a manner that is based on maintaining the reliability of the distribution system. Since the Commission is already investigating the ability to balance the Company's planned investments and increasing hosting capacity within the Company's IDP, the ALJ recommended the Commission not adopt Just Solar's recommendation to include hosting capacity as a factor in the replacement of circuit breakers, reclosers, and regulators.

D. Commission Action

The Commission agrees with the Administrative Law Judge and Company's position. The Commission finds it reasonable for the Company to prioritize asset replacement based on maintaining reliability of the distribution system through replacing equipment with the greatest risk of harming customers. The Commission therefore declines to adopt Just Solar's recommendations relating to circuit breakers, reclosers, and regulator replacement prioritizations.

LIX. Distributed Energy Resources – EV Charging Studies

A. Introduction

EV charging represents a new source of load stress to the current distribution system. To counteract this increase in load, existing and proposed pilots and programs attempt to shift EV charging energy use to time frames outside of system peak load. This is done to minimize the impact that EV charging loads have on the distribution system capacity and on large distribution capacity investments. In part, EV charging load is shifted to off-peak charging times through the Company's programs that incentivize off-peak charging with lower rate structures.

B. Position of the Parties

1. Just Solar Coalition

Just Solar argued that these EV programs create an inherent misalignment between solar DER generation and EV charging. Just Solar recommended that the Commission direct the Company to conduct additional studies to assess the potential costs and benefits that may result from encouraging EV charging during high solar generation periods. Additionally, Just Solar Coalition recommended that the Company coordinate with MISO to explore how the changing solar and DER landscapes may result in EV charging rates being dynamic based on location, solar resource availability, or other variables.

2. Xcel

In response, the Company stated that its current EV programs generally promote off-peak charging, which encourages EV charging at times beneficial to both the customers and its distribution system. The Company contended that Just Solar's recommendations relate to system planning issues outside the scope of this rate case and broader than distribution system planning, and thus would be better addressed in other forums such as an integrated resource plan proceeding. Additionally, the Company emphasized that if the Commission determines that from a policy perspective, the studies recommended by Just Solar are appropriate, it could impact other utilities not represented within this docket.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed that the recommendations on EV charging studies are outside of the scope of the rate case and would be better addressed in other forums where all potential stakeholders could engage in the proceedings. She recommended that the Commission take no action on JSC's recommendation.

D. Commission Action

The Commission agrees with the ALJ's and the Company's position that EV charging studies would be better addressed in other proceedings. As a result, the Commission will not require additional studies into EV charging as recommended by Just Solar.

LX. Distributed Energy Resources – Smart Inverters

A. Introduction

Smart Inverters is a general term used to describe inverters that meet and are certified by the Institute of electrical and Electronics Engineers (IEEE), a national testing lab. Minnesota has not yet adopted the applicable IEEE standard as part of its statewide Minnesota DER Technical Interconnection and Interoperability Requirements. As a result, certification is currently pending for available smart inverters. Smart Inverters give additional functionality including volt/watt functions[73] and volt/var curves[74] that could be utilized by DER customers.

Just Solar recommended that the Commission require the Company to leverage the capabilities of smart inverters and evaluate their ability to defer voltage-driven capital investments.

B. Position of the Parties

1. Just Solar Coalition

Just Solar argued that smart inverter capabilities have been used by peer utilities for years, and that when existing equipment is compliant and would not result in adverse system impacts, DER customers be allowed to utilize the equipment's full functionality.

2. Xcel

In its most recent IDP annual update, the Company filed a roadmap outlining a three-phase transition to the use of Smart Inverter capabilities in Minnesota. The first phase of this program is expected to be completed in the second quarter of 2023. Given the Company's roadmap and current transition, the Company argued it would be premature to assume the use of their capabilities in its planning studies or to require an evaluation of their impact. The Company noted that the use of Smart Inverters is already being addressed in the Company's IDP proceeding, which it contends is the proper venue for these issues.

C. Recommendation of the Administrative Law Judge

Since the Commission has separately addressed the implementation of Smart Inverters,[75] the Administrative Law Judge recommended that the Commission take no action on Just Solar's recommendations related to Smart Inverters.

D. Commission Action

The Commission recognizes the importance of Smart Inverters but agrees with the Administrative Law Judge and the Company that the issue is better addressed in other

[73] Volt/watt functionality allows smart inverters to monitor voltage within a local area and adjust the amount of power DERs sends to the distribution system to optimize system efficiency.

[74] Volt/var curves provide information for smart inverters to optimize photovoltaic generator efficiency.

[75] *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E-999/CI-16-521

proceedings. The Commission will not adopt Just Solar's recommendations related to the Company's use of smart inverters and the associated analysis of potential impacts on capital investments.

LXI. Distributed Energy Resources – Load Forecasting

A. Introduction

Current Company distribution planning load forecasts and capacity planning processes intentionally exclude peak load reduction effects caused by DER during peak time frames in both the present year and future forecast years. Since the Company's process operates by first removing the DER power injections, it would be possible to re-incorporate that data and examine whether any capacity investments could be deferred.

Just Solar recommended that the Company explore the impacts of DER on planned capacity investments and accordingly consider changing its approach to load forecasting.

B. Position of the Parties

1. Just Solar Coalition

Just Solar stated that integrating DERs into load forecasting would help enable the clean energy transition and modernization of the distribution system. The current system of removing DERs from load forecasting, Just Solar contends, detracts from some of the benefits that DERs provide the system. This recommendation includes requiring the Company to study the impact of its current native load compared to net load approach in system plannings. Following Commission approval of the Company's 2022 IDP, Just Solar believes the Company has begun to move in the direction of Just Solar's recommendation.

2. Xcel

The Company opposed Just Solar's recommendation on load forecasting for three reasons. First, the Company stated that it already incorporates DER forecasts into the evaluation of certain distribution capacity projects but does not include DER forecast information in some evaluations for reasons including the size of the project. The Company does not expect DER capacity to have any impact on capacity projects less than $2 million currently planned in the 2022–2024 timeframe. Second, the Company is already evaluating granular DER forecasts and scenario planning through the use of LoadSEER, to incorporate DER into its forecasting for distribution system and planning and budgeting processes. Third, the Company is preparing its 2023 IDP, through which it is assessing the current treatment of DER-derived capacity as it relates to prioritizing net load.

The Company also opposed Just Solar's recommendation to study the impact of native or net load approaches in system planning. The Company is already working on incorporating DER forecasts into its load forecasts but has not yet completed this work. DER forecasts, the Company contends, are currently not granular enough for their use in forecasting as DERs are developed for larger areas than the forecasts, causing significant uncertainty as to where the forecasted DER generation would be used. Certain DERs also cannot be relied upon for capacity reductions as certain DERs do not provide consistent capacity reductions and others have limited energy durations. Finally, the Company explained that tools such as LoadSEER require refinement over time as not only are they new to the Company, but to the industry as a whole. As a result, the Company does not plan on using short-term forecasts.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that Just Solar did not demonstrate the reasonableness of requiring the Company to study changing its approach to load forecasting and therefore recommended that the Commission take no action on Just Solar's recommendations relating to DER impacts on load forecasting and load approaches in system planning.

D. Commission Action

The Commission is not convinced by Just Solar's arguments relating to DERs and load forecasting. Given the direction the Commission has already moved in other proceedings and the recommendations of the ALJ and the Company, the Commission will not adopt Just Solar's recommendation to require Xcel to study DER impacts on load forecasting.

LXII. Grid Modernization Investigation

A. Introduction

The Company has requested cost recovery of two types of grid modernization projects: Distributed Intelligence (DI), and Fault Location, Isolation, and Service Restoration (FLISR). These projects aim to modernize the grid and assist in the Company's service of reliable energy to its customers. DI gives more insight into system issues such as outages and impedance, while FLISR allows for the Company to more quickly and accurately pinpoint where issues are occurring on the distribution system.

As part of this rate case, the Department recommended that the Company be required to comply with future grid modernization filing requirements.

B. Position of the Parties

1. Department

The Department argued that the FLISR and DI projects are discretionary grid modernization proposals that were pursued in a fashion that makes their benefits hard to ascertain. The Department recommended requiring the following standardized information in all future proposals: a road map with all planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernizations costs and all anticipated future grid modernization costs.

2. Xcel

The Company recommended not adopting the Department's proposal because while it supports efforts to improve efficiency in the regulatory process, it maintained that the Department's recommendation goes beyond the scope of this case. Additionally, the Company contended that the Department's proposed filings are overly broad and may not apply to all grid modernization proposals, and in most cases, not be possible because they would require a significant amount of speculation. The Company explained that the Commission has already issued orders implementing a framework for proposals and filing requirements which are different between cost recovery proceedings and IDP filings. The Company noted that the Department's recommendations were also proposed within the Company's 2021 IDP and the 2021 Transmission Cost Recovery Rider proceedings, and the Commission declined to adopt them at that time.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission adopt the Department's proposed filing requirements. The ALJ recognized the benefits of the information filed in aiding the understanding of grid modernization technologies and their long-term costs and benefits. The ALJ found that while the Commission did not adopt the proposals for filing requirements as part of the Company's 2021 IDP and the Transmission Cost Recovery Rider proceedings, it was to ensure flexibility to evaluate utility proposals on a case-by-case basis. The ALJ contended that adopting the Department's proposed filing requirements is consistent with the Commission's decisions in those cases by tailoring the requirements to Xcel, and additionally, that adoption of the Department's proposal in this case, does not exceed its scope.

D. Commission Action

The Commission agrees with the Department's and the Administrative Law Judge's assessment that the information contained within the Department's recommended filing requirements would be useful. The requirement would help ensure all parties have enough information in the decision-making process so that programs are thoughtfully and thoroughly designed in the future. The Commission will therefore adopt the Department's proposed filing requirements.

LXIII. Energy Assistance

A. Introduction

Energy assistance programs, such as LIHEAP, are programs that serve to aid low-income customers. LIHEAP requires customers to verify their income as part of the application process. The Company's own assistance program, PowerOn, requires customers to have applied to LIHEAP, which is a common requirement among energy assistance programs.

Just Solar Coalition proposed a set of energy assistance recommendations to address some of the issues faced by the Company's low-wealth customers.

B. Position of the Parties

1. Just Solar Coalition

Just Solar believes that the Company could improve its outreach and service to these customers to increase understanding of their economic and demographic circumstances and better protect them from service disconnections.

Just Solar contended that the Company has not given sufficient attention to issues of equity and justice affecting these consumers and recommended that the Company work with other utilities to develop a strategic plan for funding and delivering energy assistance. Just Solar recommended incorporating a reevaluation of Company budgets for low-income assistance programs to identify and assist a larger number of customers. Just Solar also recommended quantifying the difference between costs to serve single-family and costs to serve multi-family homes be quantified for consideration when setting rates. Lastly, Just Solar also recommended that the Commission require the Company to study how its demand response programs could minimize bill volatility, establish a permanent moratorium on disconnections, and remove income verification from accessing assistance programs.

2. Xcel

The Company acknowledged many of the issues raised by Just Solar are many with which it agrees; the Company shares Just Solar's objectives in assisting its members through affordable electricity. The Company, however, stated that its Energy Equity docket[76] is aimed at addressing issues surrounding the burden that energy bills place on customers. The Company's Energy Equity docket has laid a groundwork dedicated to addressing concerns regarding barriers to energy assistance programs, and the Company therefore recommended that these issues continue to be addressed in that proceeding rather than adopting Just Solar's recommendation.

C. Recommendation of the Administrative Law Judge

Recognizing the separate proceedings designed to fully consider the issues raised by Just Solar, the ALJ recommended that the Commission take no action on Just Solar's energy-assistance recommendations.

D. Commission Action

The Commission will decline to adopt Just Solar's energy-assistance recommendations, instead concurring with the Company's position that the issues of energy assistance are more appropriately addressed in the Company's Energy Equity docket where the Company is identifying proposals for consideration to address the issues surrounding its energy assistance program.

LXIV. Locational Reliability and Service Quality

A. Introduction

The concepts of locational reliability and service quality work to measure the differences seen in the service received by different communities within the Company's service area. The Company is currently working to map reliability, service quality, and equity issues in other proceedings before the Commission.[77]

[76] *In the Matter of Efforts to advance workforce diversity, inclusive participation, and equitable access to utility services for Xcel Energy*, Docket No. E002/M-22-266.

[77] *In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Docket No. E-002/CI-17-401 and *In*

Just Solar requested that, consistent with the Commission's decisions in related dockets, the Company be required to conduct analyses related to locational differences in reliability, disconnections, and service quality, specifically related to low-income and energy justice communities.

B. Position of the Parties

1. Just Solar Coalition

The proposed analysis would help inform the Company's future distribution investments and planning. Just Solar stated that the risk of disconnections and power outages have a greater disruptive effect on low-income communities. Just Solar stated that the Minneapolis Green Zone more commonly experienced outages lasting greater than 12 hours than other parts of the Company's service area.

2. Xcel

The Company stated that it has not seen systemic differences in reliability or significant patterns of poor reliability between the Minneapolis Green Zones and its other service areas. The Company is working on continuing to measure the differences in reliability and service quality across the communities it serves in its annual service quality and performance-based ratemaking dockets. The Company recommended rejecting Just Solar's proposal; the Company will instead continue its efforts in other dockets to identify and further examine these issues.

C. Recommendation of the Administrative Law Judge

Stating that the issue is more appropriately addressed within the Hosting Capacity and Grid Security Dockets cited by the Company, the Administrative Law Judge recommended that the Commission take no action on Just Solar's recommendation.

D. Commission Action

The Commission will continue to explore the issues of locational reliability and service quality within other dockets with the assistance of the Company and other interested parties. The Commission therefore declines to adopt Just Solar's recommendation related to locational reliability and service quality.

LXV. Company Audit of Third-Party Sales Forecast Data

A. Introduction

The Company currently audits economic and demographic data obtained from third-party sources and then uses the data in the development of its test year sales forecast. These audits were required by the Commission in the Company's 2008 rate case requiring the Company to work with the Department to achieve "greater data transparency." Since the 2008 rate case, the Company has audited data provided by the IHS Markit databases, which has resulted in no

the Matter of Xcel Energy's Annual Report on Safety, Reliability, and Service Quality and Petition for Approval of Electric Reliability Standards, Docket No. E-002/M- 20-406.

discrepancies being found. IHS Market is an information services company that provides information and research to its customers. Customer reliance on the information IHS provides incentivizes IHS to ensure the accuracy of the information provided.

The Company requested to eliminate its requirement to independently audit data obtained from third parties such as IHS Markit.

B. Position of the Parties

1. Xcel

The Company stated that the audits do not add value to the sales forecasts. Given the lack of discrepancies found within all the past audits, the Company argued, demonstrates that it would be reasonable to remove the audits. The Company acknowledged that updates to previous economic data have occurred but states that these updates would not have been corrected as part of the Company's audits. The data that was updated in the past was preliminary, historical economic data that is used when current data is unavailable. This preliminary data is updated when the most recent economic data becomes available, and the Company commits to resolving any third-party data issues that are identified in its sales forecast without the need to audit third-party data.

2. Department

The Department was concerned with the Company's request to eliminate the audits and cited past instances in which significant revisions to prior actual economic data occurred as support for continuing the audit requirements. The Department argued that the Company bears the burden of proving that the data and models used in creating its forecasts are reasonable. Given the need to update past economic data, the Department maintained that the continued requirement of audits ensures the data that is obtained from third parties is reasonable for use in the sales forecast modeling.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Company demonstrated that it would be reasonable to end the audit requirement and that the Department had not identified errors in preliminary historical data that the audits would have corrected. The ALJ further recommended that the Company and Department work closely to respond to issues with third-party data. The ALJ therefore recommended adoption of the Company's request.

D. Commission Action

The Commission will decline to adopt the Company's request to eliminate the required audits of data it obtains for sales forecasting from third parties. The requirement to independently audit third-party data ensures the accuracy of information used in the Company's sales forecasting. While no discrepancies have occurred in previous audits and IHS is incentivized to ensure the accuracy of data it provides, the audits continue to provide an important function of ensuring accuracy within the Company's sales forecasting.

LXVI. Regulatory Sandbox

A. Introduction

A "regulatory sandbox" is a streamlined regulatory policy meant to encourage the efficient deployment of pilot projects. The key components of a regulatory sandbox program are focused on scope, oversight and governance structure, project eligibility criteria, evaluation and reporting requirements, and methods for cost recovery or funding. Several other states currently have some form of regulatory sandbox in effect.

The Clean Energy Organizations recommended that Xcel be required to work with interested parties and other utilities to discuss methods for improving the effectiveness and efficiency of pilot programs.

B. Position of the Parties

1. Clean Energy Organizations

The benefits of such an investigation are the efficient deployment of pilot projects through a streamlined and a consistent regulatory policy that replaces the current *ad hoc* approach used for pilot projects. Additionally, this approach would ensure that the information learned during pilot projects is available to all parties and transferred into future projects.

The investigation would also facilitate coordination in the ongoing energy transition. The first issue the sandbox addresses is the frequently unreasonably long duration, from conceptualization to implementation, of pilot projects. The second issue is that pilot programs focus on individual development, not utility-wide improvements. Third, the current system operates on proposals by electric utilizes and neglects to fully incorporate ideas and experiences of third parties.

2. Xcel

The Company is concerned that a full regulatory sandbox proceeding would require extensive resources. The Company instead supports the Clean Energy Organizations' recommendation to require it to work with interested parties and other utilities to discuss methods of improving the pilot program process.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission initiate an investigation into creating a framework for rate-regulated utility projects as originally recommended by the Clean Energy Organizations. The ALJ stated that ratepayers and the public would benefit from the framework that a regulatory sandbox would provide by promoting innovation within the energy sector, innovating clean energy offerings for ratepayers, and reducing the regulatory burden of pilot programs by introducing a standardized process.

D. Commission Action

The Commission finds that initiating an investigation into the creation of a regulatory sandbox would not necessarily be more beneficial than continuing to develop these issues in individual dockets. The Commission has approved numerous pilot programs over the years, recognizing their importance in innovation within the energy sector. The Commission is not concluding that a regulatory sandbox as seen within other states would not benefit ratepayers. Rather, the Commission recognizes that such an investigation is likely to increase the scope of resources needed for such an effort, while many of these issues are under development in existing dockets. The desire to broadly coordinate efforts is not likely resolved in one proceeding.

The Commission will therefore require Xcel to work with interested parties and other utilities as relevant to discuss methods for improving the effectiveness and efficiency of pilot projects, accelerating the timeline for scaling successful pilot programs into full offerings, and increasing innovation in the energy sector, consistent with the public interest. The Commission finds that this recommendation, supported by the Clean Energy Organizations and Xcel, would benefit ratepayers and utilities without the need to create a regulatory sandbox.

LXVII. Quantifying Incremental Hosting Capacity and Beneficial Electrification

A. Introduction

The Electric Power Research Institute defines hosting capacity as the amount of Distributed Energy Resources that can be accommodated on the existing utility system without adversely affecting power quality or reliability under existing configurations and without requiring infrastructure upgrades.[78] The Company makes replacements and upgrades to its distribution resources based on asset age and renewal. These replacements and upgrades are not made with consideration to expanding hosting capacity for DER purposes.

The Clean Energy Organizations recommended that the Commission require Xcel to determine the incremental hosting capacity and beneficial electrification accommodation resulting from planned Asset Health and Reliability (AH&R) capital Expenditures.

B. Position of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that this requirement would provide insight into how Xcel's current planned Asset Health and Reliability expenditures are providing increases in hosting capacity that will be needed as the use of Distributed Energy Resources continues to expand.

2. Xcel

The Company recommended that the Commission not adopt the Clean Energy Organizations' proposal on incremental hosting capacity and beneficial electrification as the issues are outside the scope of the proceeding, and more in line with its upcoming IDP filing.

[78] Rebuttal Testimony and Schedules at 57, Marty D. Mensen, (No. E002/GR-21-630), Nov. 8, 2022.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Clean Energy Organizations recommendation be adopted. The ALJ noted that the recommendation would allow interested parties and the Commission to better assess proposed investments and prioritize those that facilitate the expansion of DERs and beneficial electrification.

D. Commission Action

The Commission will adopt the Clean Energy Organizations' recommendation to require Xcel to quantify, in its next Integrated Distribution Plan, the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments. The Commission recognizes the benefits of expanding the information available to all interested parties and the necessity of considering hosting capacity as the amount of DERs continues to expand on the electric grid.

LXVIII. Unintentional Islanding

A. Introduction

Unintentional islanding occurs when distributed energy resources (DERs) become isolated from the distribution system and continue to independently serve load. DERs are generally located near the load they serve and generally interconnect to the grid at the distribution level. This condition can be harmful to customer and utility equipment if the utility loses control of voltage and frequency. The Company's proposed solution to the problem of unintentional islanding is to upgrade substations with Voltage Supervisory Reclosing (VSR) before additional distributed generation projects can interconnect on the feeders.

The Clean Energy Organizations recommended that the Commission ask the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to investigate the problem of unintentional islanding and to research less costly alternatives to VSR to address the risk of unintentional islanding.

B. Position of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that the Company's solution to address the low-probability event(s) of unintentional islanding is too expensive. They expressed concerns that the proposed VSR investments would be too costly for DER customers and therefore recommended that Xcel file a report on the TSG's findings by July 31, 2024.

2. Xcel

The Company generally opposed the recommendations made by the Clean Energy Organizations because they are outside the scope of this proceeding. The Company also stated that the composition of the DGWG TSG has changed from technical experts to attorneys and policy advocates, a new composition which would not be effective in addressing the issue of unintentional islanding. The Company reiterated the dangers of unintentional islanding for customers and utility equipment, noting that the Company's responsibility for safe, adequate, and reliable service means that the responsibility to establish technical standards remains with the Company.

C. Recommendation of the Administrative Law Judge

The ALJ recommended requiring Xcel to examine the issue of unintentional islanding, finding that the information gathered would assist parties in addressing the risk of unintentional islanding.

D. Commission Action

The Commission concurs with the ALJ and Clean Energy Organizations to require the Company to examine this issue. While the Company's proposal of upgrading substations with VSR would provide protection against the possibility of unintentional islanding, VSR would be a costly upgrade to solve a potential problem. The Clean Energy Organizations' recommendation balances the risk of unintentional islanding against the costs of the Company's goal of preventing the problem in a manner to ensure that unintentional islanding is addressed without burdening ratepayers.

The Commission will therefore require the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to convene to examine the possibility of unintentional islanding caused by interconnection of DERs. As part of the examination, the TSG will identify additional screens that utilities can perform to assess the risk on unintentional islanding and determine if there are less costly alternatives to Voltage Supervisory Reclosing (VSR) for addressing any perceived risk. The TSG will seek feedback from the DGWG during this examination and file a report with its findings and recommendations by July 31, 2024.[79]

LXIX. Resolved Issues

On a number of issues, the parties reached agreement or resolved outstanding issues by the time the Commission met to consider the matter. The Commission concurs on the reasonableness of the resolutions reached by the parties and will adopt them, as set forth in the ordering paragraphs below.

LXX. Motion to File Late Exceptions

The Commission will grant Just Solar Coalition's motion for leave to file late exceptions to the Administrative Law Judge's Report; no party opposed this request.

LXXI. Compliance Filings

The Commission will authorize comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Xcel's proposed customer notice.

[79] The report will be filed in: *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E-999/CI-16-521

ORDER

1. Except as otherwise set forth within this order, the Commission adopts the Administrative Law Judge's March 31, 2023, Findings of Fact, Conclusions of Law, and Recommendations.

2. The Commission authorizes the Executive Secretary to open a new docket to investigate depreciation accounting or other ratemaking issues for retiring generating facilities. Any depreciation adjustments required for Sherburne County Generating Station Unit 3 or Allen S. King Generating Station will be implemented in Xcel's next rate case or other appropriate proceeding.

3. The Commission denies Xcel's recovery request of Minnesota Jurisdictional 2022-2024 long-term incentive compensation expense of $7.877 million, $8.178 million, and $8.531 million, respectively.

4. Xcel must cap its recovery of annual incentive plan compensation expense at 15% of individual base pay and 100% of target payout.

5. For each test year in the multiyear rate plan, Xcel electric's Minnesota jurisdictional annual cost recovery is limited to $1.5 million in total for the top ten highest-paid employees and officers.

6. The annual incentive plan compensation of Xcel's top ten highest-paid officers and employees is not recoverable.

7. Xcel must provide the calculation of the Minnesota jurisdictional top ten adjustment in this docket and in the annual compliance filings of the annual incentive compensation plan docket.

8. The Commission approves Xcel's 2022-2024 Minnesota jurisdictional annual incentive plan compensation expense of $22.878 million, $23.589 million, and $24.324 million, respectively which results in 2022-2024 revenue requirement reductions of $1.127 million, $1.161 million and $1.197 million, respectively.

9. Xcel must continue filing annual compliance filings evaluating the operation and performance of its incentive compensation plan and the associated refund with no changes to reporting requirements.

10. Xcel must provide support in its next annual incentive compensation compliance filing for any requested reporting changes.

11. The Commission denies Xcel's request to include its Prepaid Pension Asset in rate base to earn a weighted average cost of capital return.

12. Xcel must not recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates.

13. The Commission denies Xcel's proposal that the accrued liabilities for retiree medical and post-employment benefits be included in the rate base and earn a weighted average cost of capital return.

14. The Commission approves Xcel's 2022-2024 business systems Operations and Maintenance expenses of $89.9 million, $96.2 million, and $103.8 million, respectively.

15. The Commission denies Xcel's request to recover its income tax tracker amount, which results in a 2022-2024 revenue requirement reduction of $2.492 million, $2.300 million, and $2.110 million, respectively.

16. The Commission approves recovery of Xcel's 2022–2024 Energy Supply Operations and Maintenance expenses totaling $154.6 million, $160.8 million, and $157.7 million, respectively.

17. The Commission denies Xcel's request to recover the Aurora Solar Project's deferred costs for the difference between the contracted power purchase agreement price and South Dakota Public Utilities Commission proxy price which results in a 2022-2023 revenue requirement reduction of $2.857 million and $2.689, respectively.

18. The Commission denies Xcel's request to recover, through the Fuel Clause Adjustment, starting January 1, 2024, Aurora Solar Project's deferred costs for the difference between the contracted power purchase agreement price and the South Dakota Public Utilities Commission proxy price.

19. The Commission approves a reserve reallocation of no more than $2.14 million for recovery of a reasonable cost to dismantle, dispose of, and fully restore the site associated with the Wind2Battery system and requires Xcel to perform the proposed "inverse reverse allocation" of reallocated amounts if actual costs are lower than the $2.14 million. The Company shall not subsequently seek additional reserve allocations from assets in the Other Production plants account. The Company shall not seek recovery of any additional costs associated with the Wind2Battery.

20. The Commission approves Xcel's proposal to include Construction Work in Progress (CWIP) in rate base as an average of projected CWIP beginning and ending balances.

21. The Commission finds that Xcel's cost-benefit analysis for Fault Location Isolation and Service Restoration (FLISR) is reasonable.

22. The Commission approves Xcel's request to recover 2022-2024 FLISR program costs.

23. The Commission approves Xcel's proposed FLISR cost allocation.

24. The Commission approves Xcel's FLISR deployment strategy.

25. Xcel must track and report on reliability performance for circuits equipped with FLISR as recommended by the Department.

26. The Commission finds that any future FLISR cost recovery may be based on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR.

27. Prior to seeking future cost recovery for any incremental FLISR investments, Xcel must propose a mechanism by which to base cost recovery for FLISR investments on reliability improvements:

    a. Xcel must track and report, beginning in its next Service Quality, Safety, and Reliability report due April 2024, on reliability performance for circuits equipped with FLISR investments approved in the present rate case as recommended by the Department, indicating in the Company's safety, reliability, and service quality filings which circuits have been equipped with FLISR. Allow Xcel to modify the requirements on circuit level performance reporting in its annual Service Quality, Safety, and Reliability reports to align with the Department's recommendation.
    b. Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR's reliability results in its Integrated Distribution System Plan.
    c. In its next rate case or in any future proceeding where it seeks cost recovery for incremental FLISR investments, Xcel must propose performance targets for SAIDI, SAIFI, and CAIDI, and, if applicable, any additional aspect of FLISR, based on data collected for circuits equipped with FLISR approved in the present rate case.
    d. In the Company's next rate case or in any future proceeding where it seeks cost recovery for FLISR investments, Xcel must propose a Performance Incentive Mechanism for reliability performance demonstrated benefits of circuits equipped with FLISR, using the PIM Design Process outlined in Docket No. E002/CI-17-401. Xcel's PIM proposal shall include, at minimum, the following elements:
        i. PIM structure
        ii. The dates when the PIM will take effect and terminate
        iii. Determination of the quantifiable and verifiable incentive values associated with performance in terms of SAIDI, SAIFI, and CAIDI above and below future associated targets. This may include a neutral zone around any particular target for acceptable performance.
        iv. Specific mechanisms for effectuating a penalty or incentive on the Company
        v. An explanation of how stakeholders were engaged in the creation of PIMs
    e. Xcel must file all data as a live, .xls spreadsheet and where the data cannot be provided, explain why.

28. The Commission approves Xcel's 2022-2024 Minnesota jurisdictional distribution capital addition costs for asset health and reliability of $168.9 million, $180.8 million, and $205.0 million, respectively.

29. In its next Integrate Distribution Plan (IDP), Xcel must propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to:

a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget;
b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP.

30. Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate case filing.

31. Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.

32. The Commission rejects Xcel's distribution capital addition costs for the grid reinforcement program for the 2022–2024 test years.

33. The Commission rejects Xcel's proposal for the Distributed Intelligence program without prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement.

34. The Commission approves the Department's recommended baseline Production Tax Credits update which reduces 2022-2024 revenue requirements by $27,584,000, $1,288,000 and $1,353,000, respectively.

35. The Commission approves Xcel's proposal to recover costs for the load flexibility program that were not deferred which increases 2023-2024 revenue requirements by $0.870 million and $1.136 million, respectively.

36. Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.

37. Xcel must base 2022 insurance premium costs on historical averages as proposed by the Department which results in 2022-2024 revenue requirement reductions of $9.274 million, $10.017 million, and $11.311 million, respectively.

38. The Commission approves Xcel's request to recover Edison Electric Institute dues.

39. The Commission rejects Xcel's request to recover American Gas Association dues.

40. The Commission approves Xcel's request to recover 50% of its Chambers of Commerce dues.

41. Xcel must continue providing information mandated by Minn. Stat. § 216B.16, subd. 17, for all costs of dues it seeks to recover regardless of the type of membership (individual, corporate, or chamber).

42. The Commission disallows all 2022-2024 Carbon-Free Future Minnesota Coalition costs.

43. The Commission approves recovery of Xcel's advertising expenses.

44. Xcel must use full-time equivalent hours for its General Allocator calculations which results in 2022-2024 MN jurisdictional revenue requirement reductions of $5.900 million, $6.241 million and $6.613 million, respectively.
When allocating shared costs between its Minnesota and Wisconsin operations, Xcel shall use the 2022 Interexchange Agreement approved by FERC, thereby increasing the revenues allocated to Xcel's Minnesota operations for 2022 by $149,983, reducing jurisdictional expenses by $1,332,358, and thus reducing the overall 2022 Minnesota Jurisdiction revenue requirement by $1.482 million; Xcel must use its updated 2022 allocators in 2023 and 2024 as well.

45. The Commission adopts Xcel Energy's proposed capital structure.

46. The Commission adopts the Department's proposed cost of long-term debt.

47. The Commission adopts the Department's proposed cost of short-term debt.

48. The Commission adopts a return on equity of 9.25%, inclusive of flotation costs.

49. The Commission determines that the overall cost of capital reflects the authorized return on equity.

50. The Commission denies Xcel's proposed return on equity adjustment mechanism.

51. The Commission determines that each CCOSS model provides useful information and declines to adopt any specific model.

52. The Commission approves Xcel's proposal to classify and allocate production costs using the Stratification method.

53. Xcel must calculate the D10S allocator in its next rate case based on its system peak coincident with the MISO system peak using historical data.

54. The Commission classifies joint transmission costs as 70% demand and 30% energy.

55. The Commission allocates demand-related transmission costs using the 12CP allocator.

56. Xcel must classify and allocate distribution system costs using multiple methods, including the Minimum System Method, the Basic Customer Method, and the Peak and Average Method.

57. Xcel must file multiple CCOSSs using the following methodologies to classify and allocate distribution system costs in its next rate case:

    a. Minimum System Method
    b. Basic Customer Method, with Peak & Average Method used to classify non-Customer related cost

c. Basic Customer Method, with non-Customer related costs classified as Demand related.

58. Xcel must file a proposal for an alternative class allocation methodology for Community Solar Gardens costs recovered in the fuel clause in order to address class benefits and costs of the program. The proposal should be filed in Docket No. E-002/AA-03-802 (the fuel investigation docket) as part of the required Lessons-Learned report. The Commission will consider the issue at an agenda meeting by February 1, 2024.

59. The Commission adopts the Department's proposed 2022 test year revenue apportionment for the entire multiyear rate plan.

60. The Commission sets the monthly Small Commercial & Industrial (C&I) customer charge at $6.00.

61. The Commission sets the monthly residential customer charge for all residential customers at $6.00.

62. Xcel must work with stakeholders in Docket E-002/M-20-86 to address C&I fixed customer charges, demand rates, demand-related costs, seasonal costs and rates, and other DR and DER initiatives.

63. Xcel must implement the Low-Income, Low-Usage Discount Program as proposed by Energy Cents Coalition.

64. Xcel must make the program available to customers the later of the effective date of final rates or October 1, 2023. The Company will be required to file a program status update on December 1, 2023, and annually thereafter with its electric low-income annual report.

65. The Commission approves Xcel's practice to waive the cost-sharing requirement for electric vehicle (EV)-rate customers and require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff.

66. Xcel must include its proposal to waive cost sharing requirements for EV-rate customers to Xcel's Transportation Electrification Plan.

67. In its next general rate case, Xcel must further segment the C&I Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I TOU rate.

68. Xcel must file a proposed permanent Residential Time-of-Use rate by December 31, 2023.

69. The Commission denies Xcel's proposed changes to its Residential Space Heating tariff without prejudice; Xcel must refile its proposal in a new docket within 90 days of the final order in this case.

70. The Commission allows Xcel to discontinue its Real Time Pricing Service tariff.

71. Xcel must work with stakeholders in the development of a new Real Time pricing offering.

72. The Commission approves the Joint Stipulation between Xcel and the Suburban Rate Authority.

73. The Commission approves the structure of the rate design for street lighting as proposed by Xcel and amended by the stipulated agreement between the SRA and the Company and as recommended by the ALJ.

74. The Commission approves the new Light-emitting Diode (LED) option for Directional Lighting in the Automatic Protective Lighting Service tariff.

75. The Commission allocates $1,756,000 in pole costs across the other customer classes using the allocation factors for the Overhead Lines category as proposed by the Suburban Rate Authority.

76. The Commission opens an Advanced Rate Design docket and directs Xcel to work with stakeholders to develop a proposed scope and process for this docket.

77. Xcel must, in the advanced rate design docket, include an analysis on its compliance with Minnesota's goal for rates to be 5% lower than the national average, Minn. Stat. § 216C.05, subd. 2(4), including a minimum of the following issues:

    a. The impact of its proposed rate increase on compliance with the statutory goal;
    b. The impact of conservation on bills and its relevance to the statutory goal;
    c. Strategies that could be employed to improve compliance with the statutory goal; and,
    d. An alternate rate increase proposal that would be in compliance with the statutory goal, and Xcel's justifications for proposing any rate increases in excess of the alternate plan.

78. The Commission approves a sales true-up and not a decoupling mechanism for the multiyear rate plan.

79. The Commission modifies Xcel's proposed sales true-up as follows:

    a. Establish a 3% hard cap on surcharges.
    b. Include metered lighting in the true-up.

80. Xcel must file an annual compliance filing on April 1, with a June 1 sales true-up effective date, as recommended by the Department.

81. The Commission approves Xcel's adjustment to the Conservation Cost Recovery Factor Rider, and directs Xcel to adjust the Conservation Improvement Program Adjustment Factor (CAF) in its annual CAF filing.

82. Except as otherwise directed, the Commission approves Xcel's proposal to roll costs into final rates and carry certain projects forward in riders.

83. The Commission approves Xcel's revised Winter Construction Charges.

84. The Commission approves the Company's proposal to provide a dollar-based credit to customers on the Residential Controlled Air Conditioning and Water Heating Rider.

85. The Commission approves Xcel's 2022-2024 property tax expense recoveries of $165.930 million, $169.889 million, and $173.946 million, respectively which results in a 2022-2024 revenue requirement reduction of $14.082 million, $22.681 million, and $34.107 million, respectively.

86. The Commission approves the property tax true-up mechanism for the duration of the multiyear rate plan.

87. The Commission approves Xcel's request to amortize deferred COVID-related Business Incentive Sustainability Rider expenses.

88. The Commission approves Xcel's amortization period of three years for LED street lighting, rate expense and deferred pension expense.

89. Xcel must use its actual 2022 beginning of the year plant balance of $9,835,166.000, which reduces 2022 average rate base by $21.164 million and 2022 revenue requirements by $2.005 million.

90. The Commission reduces Xcel's 2022-2024 Nuclear Carbon Free Power Project revenue requirements by $774,000, $798,000, and $821,000, respectively.

91. Xcel must make a compliance filing that separately identifies the costs for each employee who was transferred from Xcel Energy Service to Nuclear Energy Services and that shows how the adjustments were calculated.

92. Xcel must remove $0.2 million in IVVO investments from the 2023 test year.

93. The Commission approves Xcel's proposal to remove from rate base $1.8 million in IVVO investments from 2024 test year, which results in a 2024 revenue reduction of $376,000.

94. The Commission approves Xcel's proposal to apply the return on equity approved in this rate case, instead of the Federal Energy Regulatory Commission (FERC) return on equity, to its transmission investments.

95. The Commission approves Xcel's proposal to include Workforce Development costs in this rate case, which results in 2022-2024 MN jurisdictional revenue requirement increases of $75,000, $2.000 million, and $1.670 million, respectively.

96. The Commission approves the compliance filing requirements listed in the Commission's October 23, 2009, Order in Docket No. E-002/GR-08-106.

97. The Commission approves Xcel's and the Department's proposal to remove demand-side management and distributed generation solar adjustments from the sales forecast.

98. The Commission approves Xcel's updated sales forecasts for 2022, 2023 and 2024.

99. The Commission approves Xcel's Business Incentive and Sustainability (BIS) Rider as filed.

100. The Commission approves Xcel's nuclear decommissioning accrual of $21,571,110, Minnesota jurisdictional, thus reducing the revenue requirement by $5,375,117 from each test year.

101. The Commission approves the Department's recommendation to reduce Xcel's 2022-2024 nuclear hydrogen Operations and Maintenance expense of $1.099 million, $0.509 million, and $1.345 million, respectively.

102. Xcel must extend the depreciation life of the Monticello nuclear plant by 10 years.

103. The Commission approves Xcel's 2023-2024 revenue requirement reduction of $34.5 million and $33.3 million, respectively.

104. Xcel must extend wind farm lives from 25 to 35 years, which results in 2022-2024 revenue requirement reductions of $20.809 million, $19.330 million, and $17.864 million, respectively.

105. The Commission approves Xcel's request for recovery of pension expense associated with Xcel Plan using Aggregate Cost Method, and XES Plan using FAS 87 along with amortization of the XES Plan deferred balance over three years.

106. The Commission approves Xcel's adjustments related to the three transformer sales in 2022, which result in 2022-2024 revenue requirement reductions of $0.612 million, $0.210 million, and $0.169 million, respectively.

107. Xcel must include the Minnesota portion of the North Dakota Investment Tax Credit in the revenue requirement calculations, which results in 2022-2024 revenue requirement reductions of $0.347 million, $0.496 million, and $0.712 million, respectively.

108. The Commission approves recovery of EV deferred costs, updated as of December 31, 2021, over a 3- year amortization period, which results in 2022-2024 revenue requirement increases of $0.305 million, $0.287 million, and $0.270 million, respectively.

109. The Commission approves the removal of proposed EV costs totaling: $6,238,000 in 2022; $16,124,000 in 2023; and $21,577,000 in 2024.

110. Xcel must remove EV program costs from this rate case, which results in 2022-2024 revenue requirement reductions of $1.067 million, $2.528 million, and $6.517 million, respectively.

111. The Commission approves Xcel's request to transfer any remaining book value of legacy meters at the time of complete advanced meter deployment to a regulatory asset and defer for recovery to its next rate case.

112. The Commission approves Xcel's updated revenue requirement impact of removing certain transmission cost recovery rider costs and revenues from this rate case, which results in 2022-2024 revenue requirement reductions of $0.386 million, $1.172 million, and $2.012 million, respectively.

113. The Commission approves Xcel's Nuclear Production Tax Credit tracker and refund in the annual Fuel Clause Adjustment Rider.

114. The Commission approves Xcel's proposals to include EV Program Operations and Maintenance Expense in FERC Account 912.

115. The Commission approves Xcel's proposal that the final revenue requirement be updated for secondary calculations such as cash working capital, interest synchronization, and the application of the rate of return.

116. The Commission approves Xcel's offer to withdraw its request for deferred accounting for SaaS.

117. The Commission approves Xcel's proposed capital true-up.

118. The Commission approves Xcel's proposal to continue its Property Tax True-Up during this multiyear rate plan.

119. The Commission adopts Xcel's proposal to suspend the allocation reporting requirements for Xcel Energy's transmission affiliates unless or until such work is undertaken by Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC.

120. The Commission grants Just Solar Coalition's motion for leave to file late exceptions to the Administrative Law Judge's Findings of Fact, Conclusions of Law, and Recommendations.

121. The Commission finds that the Energy Justice tenets recommended by Just Solar Coalition are relevant to setting rates in this proceeding.

122. The Commission rejects CUB's recommendation to require a five-year multiyear plan.

123. The Commission rejects the OAG's proposal to require a proceeding or stakeholder group to examine the Company's corporate governance and dividend policy.

124. The Commission declines to adopt Just Solar Coalition's recommendation relating to circuit breakers, reclosers, and regulator replacement prioritization.

125. The Commission declines to adopt Just Solar Coalition's recommendation to require additional EV charging studies.

126. The Commission declines to adopt Just Solar Coalition's recommendations related to the Company's use of smart inverters and the associated analysis of potential impacts on capital investments.

127. The Commission declines to adopt Just Solar Coalition's recommendation to require Xcel to study DER impacts on load forecasting.

128. The Commission adopts the Department's recommended grid modernization filing requirements.

129. The Commission rejects Just Solar Coalition's energy-assistance recommendations.

130. The Commission reject Just Solar Coalition's recommendation related to locational reliability and service quality.

131. The Commission declines to approve Xcel's request to eliminate its requirement to independently audit data obtained from third parties such as IHS Markit.

132. Xcel must work with interested parties and other utilities as relevant to discuss methods for improving the effectiveness and efficiency of pilot projects, accelerating the timeline for scaling successful pilot programs into full offerings, and increasing innovation in the energy sector, consistent with the public interest.

133. Xcel must quantify, in its next IDP, the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments.

134. The Commission directs the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to convene to examine the possibility of unintentional islanding caused by interconnection of DERs. As part of the examination, the TSG will identify additional screens that utilities can perform to assess the risk of unintentional islanding, and determine if there are less costly alternatives to Voltage Supervisory Reclosing for addressing any perceived risk. The TSG will seek feedback from the DGWG during this examination, and file in Docket No. E999/CI-16-521 a report with its findings and recommendations by July 31, 2024.

135. Xcel must make the following compliance filings within 30 days of the date of the final order in this case:
   a. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and including the following information:
      i. Breakdown of Total Operating Revenues by type;
      ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:
         - Total revenue by customer class;

- Total number of customers, the customer charge and total customer charge revenue by customer class; and
- For each customer class, the total number of energy and demand related billing units, the per unit of cost of energy and cost of demand and the total energy and demand related sales revenues.

iii. Revised tariff sheets incorporating authorized rate design decisions.

iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

b. Revised fuel adjustment tariffs to be in effect on the date final rates are implemented.

c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

d. A computation of the CCRC based upon the decisions made herein for inclusion in the final Order. Direct Xcel Energy to file a schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

e. If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest to affected customers.

136. The Commission authorizes comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Xcel's proposed customer notice.

137. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

for

Will Seuffert
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

CERTIFICATE OF SERVICE

I, Robin Benson, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Docket Numbers: **E-002/GR-21-630**

Dated this **17th** day of **July, 2023**

/s/ Robin Benson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties	450 Syndicate St N Ste 35 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_21-630_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_21-630_Official
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Allen	Barr	allen.barr@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Ste 1400 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_21-630_Official
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_Official
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_21-630_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Richard	Dornfeld	Richard.Dornfeld@ag.state.mn.us	Office of the Attorney General-DOC	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul, Minnesota 55101	Electronic Service	No	OFF_SL_21-630_Official
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-630_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_21-630_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-630_Official
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_21-630_Official
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Shubha	Harris	Shubha.M.Harris@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 401 - FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec	414 Nicollet Mall, 401-7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-630_Official
Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Suite 1400 St. Paul, MN 55101-2134	Electronic Service	No	OFF_SL_21-630_Official
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC	PO Box 270636 Superior, CO 80027-9998	Electronic Service	No	OFF_SL_21-630_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_21-630_Official
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_21-630_Official
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-630_Official
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-630_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-630_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 E 7th St St Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_21-630_Official
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_Official
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_21-630_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_21-630_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christa	Moseng	christa.moseng@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 Saint Paul, MN 55164-0620	Electronic Service	No	OFF_SL_21-630_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-630_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_21-630_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-630_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_21-630_Official
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_21-630_Official
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_Official
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_21-630_Official
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-630_Official
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	OFF_SL_21-630_Official
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_21-630_Official
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Scott	Strand	SStrand@elpc.org	Environmental Law & Policy Center	60 S 6th Street Suite 2800 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_21-630_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_21-630_Official
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official
Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_21-630_Official
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official

Direct Testimony and Schedules
Mark P. Moeller

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-21-630
Exhibit___(MPM-1)

Depreciation and Remaining Lives

October 25, 2021

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Mark P. Moeller. I am the Director of Capital Asset Accounting for Xcel Energy Services Inc. (XES), which provides services to Northern States Power Company (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. As Director of Capital Asset Accounting, I am responsible for various aspects of asset accounting, primarily dealing with policy, book depreciation, tax depreciation, and deferred taxes for capital assets, as well as the related reporting and regulatory requirements for Xcel Energy and its subsidiaries. A description of my qualifications, duties, and responsibilities is included as Exhibit ___(MPM-1), Schedule 1 to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I support the level of depreciation expense included in the test year, providing information on remaining lives, net salvage rates, and depreciation expense for all Company assets. My testimony also provides discussion on the overall structure of forecasted capital assets in this case for the Bridge Year of 2021, the Test Year 2022, and the plan years 2023 through 2024. I provide information on various capital plant-related issues that have been included in this case. Unless noted specifically, all numbers presented in my testimony are at a Total Company (Minnesota, North Dakota, and South Dakota) level.

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATION.

A. I recommend the Minnesota Public Utilities Commission (Commission) adopt the amounts the Company has calculated for the forecast depreciation expense in this proceeding, based on approved changes in useful life and net salvage percentage.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. I have organized the remainder of my testimony in eight parts. First, I provide some general background on the issue of depreciation along with a brief discussion of other dockets that impact the consideration of the depreciation issues in this case.

Second, I discuss the accounting for the Company's capital expenditures and capital additions, including a discussion of construction work in progress (CWIP), allowance for funds during construction (AFUDC), depreciation expense and accumulated depreciation. In this section of my testimony, I also discuss how the Company's business areas work within their capital forecasts yet remain flexible so they can respond to necessary changes, including the need to occasionally pursue similar, yet different, projects than originally anticipated to respond to emergent issues and business realities. I also discuss how the Company's overall capital additions over time align with budgeted capital additions in any given year and how variances in the Company's capital additions in any given year generally balance out as it pertains to revenue requirements impacts.

Third, I discuss the concept of "passage of time," as it relates to depreciation, including an analysis of CWIP, plant balances, book depreciation expense, and accumulated depreciation reserve over the term of the Company's multi-year rate plan (MYRP). I explain how the Company's rate request has appropriately incorporated the impact of passage of time.

Fourth, I discuss depreciation for the Company's production assets. This section discusses the impact of the Company's 2020 Annual Review of Remaining Lives filing. In this section, I also discuss the significant new projects placed in-service from 2021-2024 that impact depreciation expense in this case.

Fifth, I discuss depreciation for the Company's Transmission, Distribution and General assets (TD&G). This section of my testimony also discusses the Company's theoretical depreciation reserve adjustments, the impact of the "unwinding" of the theoretical reserve surplus, and the accounting and regulatory impacts to the Company's accumulated depreciation reserve position.

Sixth, I discuss the impact of the Commission's March 13, 2020 Order in the Company's Triennial Nuclear Decommissioning, Docket No. E002/M-17-828, along with the pending 2020 Triennial Nuclear Decommissioning Docket No. E002-M-20-855 filed on December 1, 2020, and how these filings are reflected in the MYRP.

Seventh, I discuss the rate case treatment for end-of-life nuclear fuel accruals.

Finally, I discuss tax issues impacting tax depreciation in this case.

II. BACKGROUND

Q. CAN THE COMMISSION'S DECISIONS IMPACT DEPRECIATION?

A. Yes, the Commission can make depreciation decisions in rates cases, as well as separate proceedings for:

- Production assets;
- TD&G assets; and,
- Nuclear decommissioning costs.

Q. DID THE COMPANY RECEIVE A FINAL DECISION FROM THE COMMISSION WITH RESPECT TO ANY OF THESE MATTERS IN THE LAST FEW YEARS?

A. Yes. As discussed further in Section VII, below, the Company submitted its Triennial Review of Nuclear Decommissioning on December 1, 2017 in Docket No. E002/M-17-828. In the Commission's March 13, 2020 Order, the Commission approved this Triennial Review and the Commission's ordered accruals have been incorporated into this rate case. The effect of these recently approved changes is a $13.4 million increase to nuclear decommissioning accrual effective January 1, 2021 for the Minnesota jurisdiction and a $0.6 million Total Company decrease to the end-of-life nuclear fuel accrual. In April 2021, the Commission issued an Order approving the Company's request for a rate case stay-out in Docket No. E-002/M-20-743, which allowed a one-year delay of implementing an increase to the Nuclear Decommissioning accrual and to maintain the end-of-life nuclear fuel accrual. The delayed increase results in an incremental $1.28 million increase effective January 1, 2022.

The Company received an order on September 2, 2021 for its 2020 Annual Remaining Lives Petition in Docket No. E,G002/D-19-723. The Company received approval of passage of time adjustments for electric production facilities, modification of the remaining life of the Luverne Wind2Battery System, initial remaining lives and net salvage rates for several facilities anticipated to be placed in service or acquired in 2020 and 2021, reserve reallocations to certain Steam Production accounts, and updates to the net salvage rates for electric production based on the five-year dismantling study. The approved changes from this docket have been incorporated into this MYRP.

Q. DOES THE COMPANY CURRENTLY HAVE ANY SIGNIFICANT UNDECIDED DOCKETS RELATED TO DEPRECIATION BEFORE THE COMMISSION?

A. Yes. As noted above and discussed further in Section V below, the Company's 2021 Average Remaining Lives compliance filing for TD&G depreciation rates was filed July 29, 2021 in Docket No. E,G002/D-21-584 and is currently pending. The initial compliance filing requested an increase in the average remaining life rates that would correspond to a $0.7 million increase in Electric Utility annualized depreciation expense.

Prior to the Commission's approval of the Stay Out Filing, the Company filed the 2022 – 2024 Triennial Nuclear Plant Decommissioning Study and Assumptions, Docket No. E002/M-20-855 on December 1, 2020. On July 22, 2021, the Company submitted Reply Comments with an updated 2022 accrual using assumptions as of December 31, 2020 and the $14 million accrual in 2021 as ordered in the 2021 Rate Case Stay-Out. The Company also provided an updated proposal for the 2022 accrual with the Monticello 10-year extension to address the potential recommendation from the Department. The following table reflects the updated accrual calculations:

Table 1
Updated 2022 Proposed Accrual Calculations with Stay-Out

Unit	At Current Retirement Dates	Using Monticello 10-Year Extension
Monticello	$ 6,932,038	$ 1,556,921
Prairie Island 1	13,002,996	13,002,996
Prairie Island 2	7,011,193	7,011,193
Total	**$ 26,946,227**	**$ 21,571,110**

Additionally, the Integrated Resource Plan (IRP) filed July 1, 2019 and supplemented on June 30, 2020 in Docket No. E002/RP-19-368, is also pending. While this does not change depreciation lives and rates immediately, it does inform future remaining life filings to the extent decisions are made concerning the useful lives for the Company's production assets.

Q. WHY ARE THESE PENDING DOCKETS RELEVANT TO THE CURRENT GENERAL RATE CASE?

A. Through depreciation dockets, the Commission has authority to make changes to depreciation lives and rates, which impacts expense but does not have a direct impact on rates, so the requested changes have been incorporated into this MYRP and will inform the outcome of the general rate case.

Q. HAVE YOU REVIEWED OTHER ASPECTS OF DEPRECIATION FOR THIS PROCEEDING?

A. Yes. I have reviewed the depreciation lives, net salvage rates and, where applicable, the depreciation rates for the MYRP. This review included the following:

- Known changes to the remaining lives of the production assets resulting from the forecasted changes to plant balances;
- New facilities coming online for production assets; and,
- Amortization of the regulatory asset established for the unwinding of the theoretical depreciation reserve surplus and the related amortization rates.

Q. IN THIS CASE, THE COMPANY SEEKS APPROVAL OF A MYRP. GIVEN THE MULTI-YEAR NATURE OF THIS FILING, WHAT DEPRECIATION INFORMATION IS RELEVANT?

A. The Commission's June 17, 2013 Order Establishing Conditions and Procedures for Multi-year Rate Plans contains the following requirements related to depreciation that apply to our MYRP request:[1]

- The Company must provide depreciation lives related to capital additions in each year of the MYRP. This requirement applies to capital additions in 2022, 2023, and 2024; and,
- The Company must identify changes expected in the lives of all depreciable assets for two years after the MYRP. This requirement applies to all depreciable assets during 2025 and 2026.

In addition, given the multi-year nature of the Company's request, we explain how the Company adjusts rates in years following the first year for the passage of time, showing all increased and decreased adjustments clearly, and provides support for how the Company's calculations tie out to the rate case revenue

[1] Docket No. E,G999/M-12-587, June 17, 2013, Order Point 18.

requirement requested by the Company. I discuss the issue of passage of time and its impact on the case in Section IV of my testimony.

Q. ARE YOU ANTICIPATING ANY CHANGES IN DEPRECIABLE ASSETS IN 2025 AND 2026?

A. Yes, as proposed in the IRP Alternate Plan, the Company has proposed two new combustion turbines, as well as two transmission lines to support renewable resource additions reusing interconnection rights at the Sherco and King plants, including a large solar installation at the Sherco generating plant site. These significant investments would need approval of initial lives and net salvage percentages. We also anticipate making capital additions to support our black start capabilities.

There are four wind repowering projects (Border, Grand Meadow, Nobles, and Pleasant Valley) beginning in 2021 and continuing into 2025. Border and Pleasant Valley have anticipated in-service dates in the fourth quarter of 2025, which would extend the lives of these plants. These repowers are discussed in more detail later in my testimony.

The Company is performing extensive work at the Chestnut Service Center site. Due to the age of this facility, there is substantial deterioration and obsolete technology, which has necessitated significant capital investment. The Company plans to construct a new structure just north of Xcel Energy's Riverside generation plant in Minneapolis and began site remediation in 2021. Several functions currently located at the Chestnut Service Center will be permanently moved to this new location, which will serve the Electric Utility. The Chestnut site will also have various structures redeveloped to serve our long-term needs.

Groundbreaking on this redevelopment is set to begin in 2022 and be completed in 2026.

Finally, the Company also has several large initiatives which will introduce innovative new technologies including our Advanced Grid Intelligence and Security (AGIS) system and greatly expanding electric vehicle (EV) adoption and charging stations for both residential and commercial customers. These new technologies have and may continue to necessitate either new classes of assets or may impact the statistics of existing classes of assets.

III. CAPITAL ADDITIONS

A. General Structure of Plant Forecast

Q. HOW IS THE FORECASTED PLANT INFORMATION PROVIDED IN THIS PROCEEDING?

A. The Company's approach mirrors that taken in the past several rate cases. The Company has laid out the capital forecasted information by utility (electric and common) and by functional class within utility production, transmission, distribution, general, and intangible (where applicable). In this case we have also provided a further breakdown for CWIP by showing capital budget groupings -- the categories which the business areas used to identify capital projects and create their overall capital budgets. The forecasted plant process begins with the determination of the necessary capital expenditures for the forecast period. Capital expenditures are the sum of both the construction and removal work, where construction expenditures are part of CWIP, and removal expenditures are part of retirement work in progress (RWIP) in the accumulated depreciation reserve account.

CWIP is built using the forecasted construction expenditures, typically adding AFUDC while the work is being completed (unless a current return on CWIP is permitted) and closing the construction work to plant in-service on the forecasted in-service date. The plant in-service balance will show the addition of the construction expenditures in the month CWIP closes for that work. AFUDC is stopped when the in-service date is achieved; depreciation begins when the addition is recognized. Depreciation expense is added to the accumulated depreciation reserve once the asset is placed in service.

The CWIP, plant, and accumulated depreciation reserve information is shown monthly through the entire forecast period (2020-2023) in Exhibit ___(MPM-1), Schedule 2. These reports are referred to as "roll forwards" because the monthly information is rolled forward from the beginning balance in a month by adding the monthly changes to arrive at the ending balance. This ending balance then becomes the beginning balance in the next month. This is similar to balancing your checking account by adding deposits and subtracting withdrawals to get to the balance at the end of the month. Generally, CWIP balances increase with construction expenditures and AFUDC, and decrease with plant closings. Plant balances increase with additions and decrease with retirements. Accumulated depreciation reserve balances increase with depreciation expense and salvage recognized and decrease with retirements and removal expense spent.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY THE TERM "CAPITAL BUDGET GROUPINGS" FOR EACH BUSINESS AREA?

A. Capital budget groupings are the major categories of work performed within a particular business area.

In essence, business areas calculate their budgets based on what work they deem critical to ensure continued operation of the system, identifying projects by these capital budget groupings. Therefore, the Company has presented the CWIP information aligned with each business area's capital budget groupings. The budgeted projects within these groupings are shown in Exhibit ___(MPM-1), Schedule 3. The budgeting process is discussed in more detail in the various business area witnesses' testimonies and in the Budgeting testimony of Company witness Ms. Melissa L. Ostrom.

Of course, as new facts are discovered or developed, the individual projects performed by a business area may change to deal with the new situations, but overall, the business areas stay within the overall construction and removal expenditure amounts budgeted. Substituting one project for another is a natural part of operating a business.

Q. DID THIS REPRIORITIZATION OF CONSTRUCTION WORK EXIST IN PRIOR CASES?

A. Yes. In the Company's 2015 Rate Case, Docket No. E002/GR-15-826, the Company utilized this same process of aggregating costs into capital budget groupings. This was based on a procedure established in the Company's 2013 rate case, Docket No. E002/GR-13-868, where 2014 expenditures were shifted from one related capital project to another. The Administrative Law Judge and Commission agreed these new projects should be included for ratemaking purposes. A prudently managed Company simply must respond to changes in the condition of equipment, severe weather events, changes to business or customer priorities, or the emergence of regulatory requirements not foreseen at the time its budget was created. Additionally, a change in any one of these factors from what was assumed when calculating the budget can impact the timing of capital project completion (either through delay or acceleration).

Q. CAN YOU PROVIDE MORE SPECIFIC INFORMATION ABOUT THESE CHANGES?

A. Yes. For simplicity I have summarized the changes into three general categories where the Company has experienced necessary replacement projects: (1) like-kind replacements, (2) emergent work, and (3) normal business changes. These three categories are discussed in more detail below.

Q. WHAT ARE LIKE-KIND REPLACEMENTS?

A. Like-kind replacements are new projects with work similar in scope, timing, and cost to the original projects. An example of a like-kind replacement is motor replacement/rewind projects. Often these projects are intended to ensure safe and reliable operation through the period of plant operations. However, as inspections are conducted throughout the year, the Company determines with more certainty which motors require capital repairs. The motors that require capital repairs may have been forecasted in the first year of the budget or they may have been included in a later year. If motors were originally forecasted to be replaced in the first year but based on the Company's business and engineering judgment as the year progresses, the Company determines replacement is not necessary during the first year, it will postpone the originally forecasted motor projects to a future year of the budget. At the same time, the Company may determine it needs to bring other motors needing replacement or repair into the current year forecast. This reprioritized motor replacement schedule can be driven by the following factors: plant scheduling, manufacture lead-time and efficiencies, budget constraints due to regulatory project costs, and ensuring the availability of the spare motors during the installation of new motors for risk reduction and assurance. Overall plant reliability, project scope, timing and cost will not be significantly impacted by this exchange of like-kind replacements. In fact, by moving lower priority items out of the forecasted year and bringing higher priority items in, overall plant reliability is maintained.

Q. WHAT IS EMERGENT WORK?

A. During the course of a year, the Company's business areas may encounter work not originally planned for during the budgeting process (e.g., major break-fix projects, projects needed to be responsive to new regulatory requirements, etc.). This is known as emergent work. Once emergent work is identified, the business areas determine whether room exists within the current budget to support the additional work or if the emergent work is higher priority than work currently underway or planned for the year. In the latter case, the Company reallocates funds to the emergent work and delays or cancels the initially budgeted capital projects.

Q. WHAT ARE NORMAL BUSINESS CHANGES?

A. During a year, the Company's business areas may postpone or cancel a project and replace it with a different, more time-sensitive project to be completed during the year. Although the cancelled project would no longer be pursued in that year, the capital associated with it will be reallocated to other priorities. These changes can occur due to unpredictable events requiring unbudgeted capital expenditures after the budget is finalized. For example, Energy Supply may postpone a new roof or the resurfacing of a parking area in favor of a more urgent project needed to maintain or even improve plant reliability. Ultimately, the Company will manage its capital projects to operate within its budget, comply with regulatory requirements, and adapt to changing circumstances. The flexibility to adapt to changing circumstances allows the Company to reprioritize capital projects, which ultimately benefits its customers.

Q. ARE THERE CIRCUMSTANCES IN WHICH PROJECTS ARE CANCELLED OR ABANDONED?

A. There are projects that are not completed as originally scheduled so others can take their place. This is a reasonable, but infrequent occurrence. Truly cancelled or abandoned projects, meaning projects for which the forecasted dollars do not get used, are not common.

Q. WERE ANY PROJECTS CANCELLED OR ABANDONED IN 2021 THROUGH THE END OF THE MYRP?

A. No projects have been cancelled in 2021-2023. The Integrated Volt-Var Optimization (IVVO) project included in 2024 is being reevaluated, and the Company no longer intends to install in 2024. The total budgeted capital expenditures in 2024 is $5.0 million with estimated in-servicing of $4.7 million during the MRYP period. We will update our cost of service accordingly in rebuttal. The Sherco Unit 4 combined cycle project has been suspended until the IRP has been resolved. No spend or in-servicing for this project has been included during 2022-2024.

Q. YOU HAVE EXPLAINED HOW BUDGETS NEED TO BE FLEXIBLE BECAUSE CIRCUMSTANCES CHANGE, BUT HOW DOES THE ESTIMATED IN-SERVICE DATE IMPACT THE CAPITAL ADDITION?

A. Think of the estimated in-service date as the asset's birth date. At the beginning of the planning cycle, the business areas estimate the time it will take to get ready for construction (obtain permits or certificate of needs, order material, perform required studies, and complete the required engineering or project planning), the time it will take to actually build or create the asset, and then to complete construction (testing the asset, connecting it to the grid, satisfying permit requirements, and gaining the necessary agency approvals). After they lay out this process, the business area can provide the estimated in-service date. Only when all the actual work is complete will the business area know whether their estimated in-service date was accurate. However, the business areas understand the necessary steps to get a project to its in-service date and have significant experience moving projects through this process, so we can reasonably anticipate the estimated in-service date will be in line with expectations, absent some changed circumstance that significantly alters the expected timeline.

Q. WITH ALL OF THESE CHANGES HAPPENING IN ANY GIVEN YEAR, HOW CAN THE COMMISSION HAVE CONFIDENCE THE COMPANY'S CAPITAL BUDGETS PROVIDE A REASONABLE BASIS FOR SETTING RATES?

A. Ms. Ostrom discusses this in greater detail, but from a capital asset accounting perspective, it is important to recognize overall actual capital additions have closely aligned with budgeted additions. There are slight variations in any given year; however, the overall impact to the revenue requirement is small. For example, if a project is forecasted to be in service in July and it actually goes into service one month earlier or later, the impact for a $1 million project assuming a 40-year useful life is approximately $2,000 in changed revenue requirement. Even if the addition was forecasted to be a December occurrence and ended up occurring in January of the next year, the impact to revenue requirements is not dramatic since the inclusion of CWIP in rate base means the revenue requirement difference is limited to one month's depreciation.

Variations in capital expenditures may have even less of an impact on the revenue requirements than variations in capital additions, especially when the total spend of the project is met and the in-service date does not change. The variation of capital expenditures may not change the overall level of additions in a given year. Thus, capital expenditures would need to affect the actual level of additions in order to cause an impact to the revenue requirement. Lastly, capital expenditures in one project work order may vary in one direction with another varying in the opposite direction. This may also occur with capital additions. For all these reasons, the total capital expenditure and addition picture must be considered when evaluating the impact to the revenue requirement and considering whether the Company's capital budgets provide a reasonable basis for setting rates.

Q. DO YOU PROVIDE AN ANALYSIS OF ACTUAL CAPITAL EXPENDITURES COMPARED TO BUDGET?

A. No. Ms. Ostrom addresses this in her testimony.

Q. DO YOU PROVIDE AN ANALYSIS OF ACTUAL CAPITAL ADDITIONS COMPARED TO BUDGET?

A. Yes. We compared 2018 through 2020, the last three full actual years, for capital additions. Capital additions influence the overall impact on revenue requirements. The following table shows the comparison for capital additions for the past three years:

Table 2
Plant Additions for 2018 through 2020

	2018	2019	2020
Actual	1,025,950,121	1,166,194,383	1,515,404,249
Budget	1,087,565,159	1,920,383,732	2,130,398,873
Variance	(61,615,038)	(754,189,348)	(614,994,725)
% Accuracy	94.3%	60.7%	71.1%
Total average accuracy			75.4%

Thus, the actual capital additions over this three-year period were within 75.4 percent of budgeted additions.

Q. CAN YOU PROVIDE ADDITIONAL EXPLANATION FOR THE VARIANCES IN 2019 AND 2020?

A. Yes. Approximately $795 million of underruns in 2019 was related to the timing of in-servicing the Crowned Ridge and Blazing Star I wind farms. The original budget assumed those wind projects would go into service in December 2019. These assets are addressed in the Renewable Energy Standard rider.

Approximately $635 million of underruns in 2020 was related to the following issues: (1) after the 2020 budget was prepared, there was a scoping change to the Crowned Ridge project which reduced the size from 300 MW to 200 MW, thus, reducing the amount of capital by approximately one-third (+$187M), (2) Blazing Star I wind originally assumed an in-service date of December 2019 in the budget but actually went into service in April 2020 (-$304M), and (3) Blazing Star II, Mower, and Freeborn were all originally anticipated to go into service in December 2020 but actually went into service in January 2021, March 2021, and May 2021, respectively (+$752M).

If you were to exclude those large projects from the 2019 and 2020 budgets, the three-year average accuracy rate would be 99.8 percent as shown in Table 3 below. This, combined with the capital expenditures analysis, demonstrates the reliability of the Company's budget process and the reasonableness of using the Company's capital budgets as the basis for setting rates.

Table 3
Plant Additions for 2018-2020 (Excluding Certain New Wind Projects)

	2018	2019	2020
Actual	1,025,950,121	1,166,194,383	1,515,404,249
Budget	1,087,565,159	1,124,457,006	1,495,470,594
Variance	(61,615,038)	41,737,377	19,933,654
% Accuracy	94.3%	103.7%	101.3%
Total average accuracy			99.8%

Q. WHAT WAS THE CAUSE OF THE SHIFT IN IN-SERVICE DATES?

A. COVID-19 has impacted Energy Supply's capital investments in that projects have experienced schedule delays and cost increases due to supply chain issues. The largest impact has been the delay of the completion of the Freeborn, Mower County, and Blazing Star II wind farm projects from 2020 to 2021 due to wind turbine delivery delays.[2]

Q. WHAT IMPACT DID THIS DELAY HAVE TO CUSTOMER RATES?

A. Because these wind farm costs are recovered directly through the RES rider, the delay in implementation of these facilities also resulted in corresponding delays in the recovery of these costs from customers through the rider. As a result,

[2] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan*, COMPLIANCE FILING-QUARTERLY REPORT, Docket No. E002/M-16-777 (July 31, 2020).

there is no financial detriment to customers or incremental benefit to the Company as a result of these delays.

B. Traditional Approach for the MYRP

Q. WHAT IS THE TRADITIONAL APPROACH?

A. The traditional approach means the expenditures are forecasted at project level in order to provide the appropriate spend within the various business areas. The projects have been summarized by the capital budget groupings for each business area in Exhibit___(MPM-1), Schedule 3, and the annual effect of these additions is included in the calculation of revenue requirements for the forecast test and plan years 2022 – 2024. In addition, Exhibit___(MPM-1), Schedule 4 provides detail on the expenditures and additions by each business area witness.

Q. WHAT IS THE INTENT OF THESE CAPITAL BUDGET GROUPINGS?

A. The capital budget groupings by business area were created to help identify and categorize the critical work needed to be done by each business unit.

Q. CAN YOU PROVIDE THE CAPITAL BUDGET GROUPINGS USED IN THE FORECAST?

A. Yes. The following table summarizes the capital budget groupings by business area for the capital work in 2022 - 2024, including the witness supporting the business area. These same groupings are used for the entire forecast as well.

Table 4

Capital Budget Groupings by Business Area[3]

Energy Supply – Randy Capra	**Business Systems – Michael Remington**
• Coal • Dispatchable • Hydro • Intermediate • Solar • Wind	• Aging Technology • AGIS • Customer • Cyber Security • Emergent Demand • Enhance Capabilities
Nuclear – Peter Gardner	**Distribution – Kelly Bloch**
• Dry Cask Storage • Facilities and Other • Improvements • Mandated Compliance • Nuclear Fuel • Reliability	• AGIS • Asset Health & Reliability • Capacity • Electric Vehicles • Fleet, Tools, and Equipment • Mandates • New Business
Transmission – Ian Benson	**Facilities – Mark Moeller**
• Asset Renewal • Communication Infrastructure • Interconnection • Regional Expansion • Reliability Requirement • Security/Resiliency	• Enhance Capabilities • Enterprise Security Capital • Fleet, Tools, and Communications • Other • Property Services Capital
Fleet – William Husen	
• Fleet, Tools, and Communications • Fueling Depots • PHEV (Plug-in Hybrid Electric Vehicles) • Replacements, Additions, & Repairs	

Q. ARE YOU SUPPORTING CAPITAL EXPENDITURES IN THIS CASE?

A. Yes. I present a small part of the capital forecast for miscellaneous capital expenditures related to general facilities used by the Company. While I do not directly oversee the construction or purchase of these assets, I can speak to the

[3] Management of the capital fleet budget (Fleet Capital) was mostly centralized within Supply Chain in November 2018. As a result, Company witness Mr. William K. Husen now provides testimony supporting a portion of Fleet capital. Prior to this centralization, each operational business area was responsible for budgeting fleet capital investments.

capital budget groupings. The facilities capital expenditures are shown under the capital budgeting groups Enterprise Security Capital, Other, and Property Services Capital. These groupings include work on the building systems, furniture, leasehold improvements, structural components, tools, and other equipment necessary to support the operations of the office buildings and service centers. These expenditures, which are incurred to maintain and update existing facilities, are appropriate capital expenditures.

Q. CAN YOU DESCRIBE THE CAPITAL WORK BEING DONE IN THE BUILDINGS AND GENERAL?

A. There are a handful of large initiatives driving the Property Services work in the MYRP in addition to routine capital maintenance projects. The major projects with expenditures greater than $10 million during 2022-2024 are as follows:

- Redevelopment of the Chestnut Service Center;
- The Marshall Operations Center;
- A new service center in Shorewood, MN;
- New construction at Grand Forks, ND; and
- The Sioux Falls, SD renovation.

The capital expenditures and additions included in this case for 2021 – 2024 for these groupings are shown in Table 5 below.

Table 5

Facilities Capital Expenditures and Additions for 2021 through 2024

(in millions)	2021	2022	2023	2024
Expenditures	$50.9	$64.3	$73.0	$35.5
Additions	$25.6	$84.2	$47.2	$19.5

Q. CAN YOU DESCRIBE THE RENOVATION AND REPLACEMENT CAPITAL WORK BEING DONE ACROSS THE PROPERTY SERVICES PORTFOLIO?

A. Property Services is responsible for operating and maintaining Company owned and leased sites for regional and headquarters offices, service centers, and call centers. It is not responsible for facilities at power plants, substations, gas regulator sites, or transmission sites. Capital projects are required to bring sites up to code and keep the asset in operation.

Building capital projects typically include replacing the electrical, mechanical, and plumbing systems, replacing structural components such as windows and roofs, and replacing carpet. Pavement replacements address deteriorating surfaces which hinder vehicle traffic and parking. Mechanical projects typically include replacing HVAC equipment for control of offices, and exhausting and heating vehicle and warehouse areas. Roof replacements are completed based on age and condition and expanded upon when necessary to include any repairs caused by leaks or other issues (mold remediation, condensation, etc.). Dollars are also budgeted for unplanned emergencies such as storm damage or flooding causing interior and exterior damage. In the event the building is no longer sufficient to house the intended operations, a new facility is constructed, generally, near the original site. The capital additions for this section are expected to be $25.6 million in 2021, $84.2 million in 2022, $47.2 million in 2023, and $19.5 million in 2024.

Major projects include the following:

- Chestnut Service Center Redevelopment Phase 1 – Master planning to re-develop the existing Chestnut campus for more efficiency. The construction will address all deferred maintenance projects, code issues, space limitations for vehicle storage, equipment storage, labs, materials, warehousing, workspaces. This includes demolition of several structures beyond their useful lives, and environmental cleanup, as needed. As well as new construction of any facilities to support the non-service center functions that will remain at the existing campus. Current expenditure forecast for redevelopment is $5.3 million in 2022, $19.5 million in 2023, and $24.8 million in 2024. This project is expected to be completed in 2026 (which is why we focus on expenditures here rather than additions).

- Marshall Operations Center Development - As part of the Chestnut master planning, a new site development is being completed. This includes the design, engineering, site development, and construction of an approximately 100,000 square foot commercial class B office building near Riverside Plant. The construction will include lower-level storage, 1st, 2nd, and 3rd floors, and parking for approximately 200 vehicles. Environmental remediation of the site and initial construction is to occur in 2021 with construction currently anticipated to be complete by the end of 2022. This project is forecast to be a $32.5 million addition in 2022.
- Shorewood New Service Center – This is a new facility that consolidates the current Shorewood Service Center and Waconia Service Center through land acquisition in Chanhassen, MN, and development of the site to accommodate the functions of both service centers. This will reduce overall operating costs and improve functionality of service operations. Land acquisition to occur in 2021, site and facility design in 2022, and construction to be completed in 2023. The current forecast for spend on this building and facilities is $0.9 million in 2022 and $16.4 million in 2023. Capital additions are estimated at $17.6 million in 2023.

- Grand Forks Service Center – The existing Grand Forks Service Center is outdated and deteriorating; renovation has been determined to be an inferior solution to new construction due to high cost. A new facility will be constructed on the existing property to accommodate the needs of the service territory. Design to occur in 2022, construction to take place in 2023. Total additions going into service are $12.7 million in 2023.
- Sioux Falls Service Center – Operations working from this location have outgrown the capacity for which it was intended. To meet the growing needs, Property Services has decided the most efficient solution is to acquire and redevelop the adjacent property. Property acquisition to occur in 2021, site and facility design to take place in 2022, and renovation/construction of entire site to occur in 2023 and 2024. Work to include expansion of existing spaces (break rooms, conference rooms, crew quarters), repurposing of existing fleet space, construction of new fleet building, and yet-to-be determined renovations of the acquired site. Current forecasted expenditures for the updates at this location are $0.6 million in 2022, $8.6 million in 2023, and $2.8 million in 2024. Capital additions are estimated at $12.2 million in 2024.
- Other major projects include expansion of the training center in Hugo, renovations at the Edina Service Center, new service centers in Belgrade and Belle Plaine, and vehicle storage in St. Cloud. These five projects total $34.4 million of capital to be in-serviced in 2022-2023.

Q. ARE THERE ANY OTHER SIGNIFICANT FACILITIES PROJECTS CURRENTLY PLANNED BEYOND THE TEST AND PLAN YEARS?

A. The Chestnut Service Center project discussed above will continue until the 2026 anticipated in-service date. Other than that, there are no significant projects identified in 2025-2026 for facilities at this time.

IV. PASSAGE OF TIME

Q. PLEASE EXPLAIN WHY THE CONCEPT OF PASSAGE OF TIME IS RELEVANT TO THIS CASE.

A. The concept of passage of time pertains to how the Company's rate base and revenue requirements change from one year to each subsequent year. This includes an analysis of CWIP, plant balances, book depreciation expense, and accumulated depreciation reserve over the course of a MYRP.

Q. HOW DOES THE RATE BASE CHANGE FOR A SINGLE ASSET AS IT PASSES THROUGH TIME?

A. The first year an asset is in use, the beginning and ending average is based on the beginning CWIP balance (if there is one) and the ending plant balance. This asset is only partially included in rate base, assuming the CWIP balance at the beginning of the year was less than the total asset value when it moved to plant in service. The second year and beyond, the asset's original cost remains constant until the year it is retired, which is a partial year. The accumulated depreciation reserve grows each year with the depreciation expense recognized, with the first and last years of the asset's life being a partial expense. Combining the plant and accumulated depreciation reserve each year for this single asset, one would see a decreasing rate base until the asset is fully depreciated.

Q. HOW DOES A PLANT RETIREMENT IMPACT RATE BASE OVER THE PASSAGE OF TIME?

A. A retirement transaction results in the plant and reserve balances being decreased by the same amount. The act of "retirement" has no direct effect on rate base, but it does have an indirect impact as discussed below.

Q. CAN RETIREMENTS IMPACT DEPRECIATION AND THUS INDIRECTLY IMPACT RATE BASE OVER THE PASSAGE OF TIME?

A. Yes, but it depends on the type of asset and depreciation method used for the asset as to whether there is a depreciation impact resulting from the retirement. A retirement reduces the plant balance and the accumulated depreciation reserve by the same amount when the transaction is recognized, resulting in no impact to rate base from the transaction. However, there are assets where the depreciation is calculated from the original cost of the plant and not the net plant value. For those assets (depreciation on original cost), the retirement does change the calculation of the depreciation going forward and this change impacts the accumulated depreciation reserve and, hence, rate base. For all transmission and distribution assets and general plant buildings, there is an impact on the depreciation expense going forward from the point a retirement is made because the retirement decreases the original cost of plant and these assets use a depreciation rate applied to the original cost of plant. Thus, indirectly these retirements impact the overall rate base because of the change to depreciation expense in the year the asset retires and its change to accumulated depreciation reserve.

For electric production assets, the remaining life method of depreciation is used, which depreciates the net plant over the remaining life. For these assets a retirement does not change the net plant, thus there is no change to depreciation expense going forward from the retirement of the asset. Accordingly, there is no impact to rate base for the electric production retirements. For plant assets using the vintage group method as described in Federal Energy Regulatory Commission (FERC) Accounting Release No. 15 (AR-15), distribution meters, line transformers, and general plant assets (excluding general plant buildings), a retirement is not recognized until the assets for a particular vintage are fully depreciated. There is no impact to rate base for the vintage group retirements.

Q. HAS THE COMPANY INCORPORATED THE FULL PASSAGE OF TIME CHANGES INTO THE 2023 AND 2024 PLAN YEARS?

A. Yes. All assets in plant at the end of 2022 were advanced forward into the 2023 plan year, and 2023 balances were advanced forward into the 2024 plan year. The Company has included all changes in plant balances, depreciation expense, and accumulated depreciation reserve during 2023 and 2024 in its request for both plan years, using a full cost of service approach, which is addressed in Company witness Mr. Benjamin C. Halama's testimony. The roll forwards of CWIP, plant, RWIP, and accumulated depreciation are included in Exhibit___(MPM-1), Schedule 2. We also provided a summary for 2022 through 2024 in Exhibit___(MPM-1), Schedule 5. This schedule provides a link from the information in my Exhibit___(MPM-1), Schedule 2 to Mr. Halama's Schedule 9 for the 2022 test year and provides the unadjusted information for the 2023 and 2024 plan years.

Q. IS THIS A CONSISTENT APPROACH AS USED IN THE 2015 RATE CASE?

A. Yes, in the 2015 Rate Case, the Company used the same method of providing full revenue requirements for all plan years in support of the revenue requirement.

V. DEPRECIATION FOR PRODUCTION ASSETS

Q. DOES THE COMPANY FILE ANY UPDATES WITH THE COMMISSION REGARDING ITS REVIEW OF DEPRECIATION FOR PRODUCTION ASSETS?

A. In general, each year in February the Company files an annual review of remaining lives for production assets, proposing changes to depreciation expense based on any changes to remaining lives or net salvage rates identified in its annual review.

Q. PLEASE DESCRIBE THE PROCESS USED TO IDENTIFY CHANGES THE COMPANY INCLUDES IN ITS REVIEW OF REMAINING LIVES FILING.

A. The Company follows the same process used to complete each remaining life filing. Annually, the Company's depreciation analysts meet with the employees who are knowledgeable about the planning, construction, and operations at each facility. During these meetings, the Company reviews each facility to:

- Understand the major overhauls, rebuilds, and routine construction projects performed over the past few years;
- Consider the scope of current and upcoming projects; and,
- Forecast the likelihood of the facility achieving the currently approved remaining life in light of the past, current, and near future projects.

If the Company determines the current remaining life is no longer appropriate, the Company proposes a modification to the remaining life for the facility.

The Company also considers the likelihood that a planned major overhaul, rebuild, or routine construction project will occur in the next 10 to 12 months, and its probable effect on each facility. If there is uncertainty whether the work will occur, the Company reduces the weight given to this factor in its remaining life analysis. Each year, the Company reviews the projects scheduled for each plant to gauge if there is more or less certainty of completion, and it adjusts its analysis accordingly.

Occasionally, there is a significant individual event that influences a change to remaining life – for example, the operating license renewal at Monticello. More often, however, it is a culmination of several smaller factors that, when considered together, support a change in the remaining life. If just one or two of these small changes are present, the factors may not be strong enough to influence a life change. As time passes each year, more of these smaller factors may be realized such that a change would become appropriate.

Q. DOES THE COMPANY PRESENT A REVIEW OF REMAINING LIVES IN THIS RATE CASE?

A. No, the Company does not. The remaining lives filing is a depreciation docket in which intervenors file comments and the Commission ultimately orders changes to the depreciable lives the Company will use to record expense and file for rate recovery. While the Commission can choose to order changes to depreciable lives within a general rate case docket, the depreciation dockets are typically used to provide a basis for the initial revenue requirement filing. As described below, the Commission has issued an order on the 2020 Annual Review of Remaining Lives filing, and the approved changes have been incorporated into this MYRP.

A. 2020 Remaining Lives Filing (2022 Impact)

Q. PLEASE SUMMARIZE THE STATUS OF THE COMPANY'S 2020 ANNUAL REVIEW OF REMAINING LIVES.

A. The Company received an order on September 2, 2021 in its 2020 Annual Review of Remaining Lives Petition in Docket No. E,G002/D-19-723. The approved changes from this docket have been incorporated into the general rate case filing and are shown in Exhibit____(MPM-1), Schedule 6.

Q. WHAT DID THE COMPANY INCLUDE FROM ITS 2020 ANNUAL REVIEW OF REMAINING LIVES FILING IN THE INITIAL FILING IN THIS CASE?

A. In the Company's 2020 filing, it received approval of changes to its electric production facilities. The Company included the approved position in its initial filing in this rate case, which included the following:

- Reduction of two years to move forward the remaining lives for all electric facilities from the life previously approved that were not recommended for a further change;
- Modification to the remaining life of the Luverne Wind2Battery System;
- Initial remaining lives and net salvage rates for Blazing Star II, Crowned Ridge, Freeborn, Dakota Range, Jeffers, Community Wind North, and Mower wind projects which were acquired or in-serviced during 2020 and 2021;

- Reserve reallocations to certain Steam Production accounts;
- Updates to the net salvage rates for electric production (excluding the Luverne Wind2Battery System) based on the 2020 dismantling study; and,
- The effective date for the changes to be January 1, 2021.

The approved changes in this Petition are reflected in the MYRP depreciation expense, causing an increase in Total Company depreciation expense for 2022 of $4.2 million.

Q. PLEASE DESCRIBE THE 2020 DISMANTLING STUDY AND HOW IT IMPACTS THIS CASE.

A. Every five years, we commission a dismantling study to determine a site-specific cost estimate for all non-nuclear Electric Production assets. The 2020 Dismantling Study was performed by TLG Services (TLG). The main purpose of the 2020 Dismantling Study was to estimate the present-day costs for retiring and demolishing the facilities, also known as final removals of existing facilities. These estimates are then used to calculate the net salvage rates necessary to recover removal costs for our production assets.

Q. ARE THERE SIGNIFICANT PROJECTS THAT WOULD FURTHER IMPACT THE DEPRECIATION EXPENSE IN 2022-2024 AND ARE THESE IMPACTS INCLUDED IN THIS CASE?

A. Yes. Plants with new or revised remaining lives due to additions are discussed in Exhibit____(MPM-1), Schedule 7. This schedule shows the plant and accumulated reserve roll forward activity for four major projects anticipated to be in-serviced in 2021 (Blazing Star II, Dakota Range, Freeborn, and Mower), one major project in 2022 (Northern Wind), and Sherco Solar is anticipated to go in-service in several stages in 2023 and 2024 with additional in-servicing after the MRYP period. We are also undergoing four wind repowering projects as discussed in more detail below. These major projects would impact depreciation expense during the MYRP for those included in base rates. There are several projects which will be included in the Renewable Energy Standard (RES) rate rider. Mr. Halama explains in his testimony the asset costs of these RES Projects and their related depreciation expense are removed from general rates at issue in this case. The table below shows the delineation between base and RES projects.

Table 6

Significant Projects

Project	Anticipated In-service Date	Included in RES Rider or Base Rates
Blazing Star 2	Jan. 2021	Base
Mower	March 2021	Base
Freeborn	May 2021	Base
Dakota Range	Dec. 2021	Base
Northern Wind	Dec. 2022	RES Rider
Sherco Solar	Various dates 2023-2025	RES Rider
Wind repowers	Various dates 2022-2025	RES Rider

Q. WHAT DOES THE COMPANY RECOMMEND FOR THE REMAINING LIFE AND NET SALVAGE FOR THE NEW WIND FARMS?

A. The initial life and net salvage rate for the Blazing Star II, Mower, and Dakota Range projects were approved in Docket No. E,G002/D-19-723. The Company proposes the remaining life of the Northern Wind project be set to 25 years at its in-service date. This is consistent with the treatment of the Company's other wind farms currently on the system, though, as noted below, an extended life may be appropriate for many of our wind facilities.

Notwithstanding such a potential extension, however, a 25-year life is comparable to the expected remaining life stated by the manufacturer of the turbines being used at these facilities. The lives of these wind farms are evaluated on an annual basis, and so far, all the wind farms are performing as anticipated and are expected to meet this useful life. In fact, there are more frequent occurrences of regulatory lives beyond 25 years, but there is still little retirement history available to validate actual expected lives. The main components that would influence the life of a wind turbine are the life of the nacelle and the blade. The Company has experienced some early failures of these components, but not to a magnitude that would suggest a shorter life is more appropriate, or that extension of wind facility lives is not reasonable.

The Company is also recommending a net salvage of negative 10.5 percent for this project. The wind farms which are anticipated to go in-service later in 2021 and 2022 were not included in the 2020 Dismantling Study because the projects were still under construction or had not yet been acquired at the time the study was performed. The negative 10.5 percent net salvage represents a simple average of the net salvage percentages from the eight farms included in the 2020 Dismantling Study.

Q. WHAT WIND GENERATING SITES ARE CURRENTLY APPROVED FOR REPOWERING AND HOW DOES THIS IMPACT CAPITAL AND COST RECOVERY?

A. To support economic relief and recovery in Minnesota in the wake of the COVID-19 pandemic, supporting job creation while also achieving cost savings for customers, the Company received approval, in a January 22, 2021 Order in Docket No. E-002/M-20-620, to repower four currently existing wind facilities – Border, Grand Meadow, Nobles, and Pleasant Valley.

The table below shows the estimated in-service date of each repowering along with the number of years the life of the facility would be extended. We propose the new retirement end of life date become effective upon the in-service date of the repowering.

Table 7

Impact of wind repowers on retirement dates

Plant	Estimated In-Service Date of Repower	Years of extended life	Current retirement	New retirement
Nobles	Dec. 2022	10	Nov. 2035	Nov. 2045
Grand Meadow	Nov. 2023	10	Nov. 2033	Nov. 2043
Border	Nov. 2025	9	Dec. 2040	Dec. 2049
Pleasant Valley	Nov. 2025	9	Dec. 2040	Dec. 2049

In our initial petition to Docket No. E002/M-20-620 *Wind Repowering Request for Proposals*, the Company proposed to recover its costs either in the RES Rider or in base rates. Such requests would include both the existing rate base on the four existing facilities, as well as the new rate base associated with the repowering, over the newly extended lives of the repowered projects.

B. Future Remaining Lives Changes

Q. ARE THERE ANY OTHER FACTORS THAT WOULD FURTHER IMPACT THE DEPRECIATION EXPENSE IN THIS CASE?

A. Yes, the Company's July 1, 2019 IRP filing is currently pending, which includes the IRP Alternate Plan as filed in June 2021. Future orders on this pending docket could impact depreciation expense. The proposed existing plant life changes filed in the IRP have not been included in this rate case.

As discussed by Company witness Mr. Greg Chamberlain, the Company is proposing a capital true up mechanism in this case, similar to what was entered into in the past MYRP and 2020[4] and 2021[5] Stay Outs. Such a mechanism would include any downward adjustments that may result from this study and would thus protect customers from any potential for over-payment due to this study.

C. Wind Life Extension

Q. HAS THE COMPANY ASSESSED THE POSSIBILITY OF EXTENDING THE LIVES OF WIND ASSETS BEYOND THE CURRENT LIVES?

A. Yes. The Company regularly reviews wind turbine lives utilized in other jurisdictions Within these assessments, the Company considers support requirements necessary to justify extensions. These can include structural design, technology used as well as weather and atmospheric conditions applied to the turbines.

Q. WHAT TYPES OF TRENDS IS THE COMPANY SEEING AS IT RELATES TO WIND TURBINE LIFE EXPECTATIONS?

A. The Company is seeing some trending up from the standard 25-year life expectancy used by NSPM to 30 and 35 years.

Q. ARE THERE SPECIFIC WIND ASSETS OWNED BY THE COMPANY YOU BELIEVE WOULD BE GOOD CANDIDATES FOR LIFE EXTENSION?

[4] E,002/M-19-688 In the Matter of the Petition of Northern States Power Company dba Xcel Energy for Approval of True-up Mechanisms

[5] E,002/M-20-743 In the Matter of the Petition of Northern States Power Company dba Xcel Energy for Approval of 2021 True-up Mechanisms

A. Yes, we believe all wind projects except those undergoing repowering (Border, Grand Meadow, Nobles, and Pleasant Valley) or which have been repowered already by reusing the foundations and towers (Community Wind North, Jeffers, and Mower) could be included in this extension.

Q. HOW WOULD EXTENDING THE LIFE ON THESE ASSETS IMPACT ANNUAL DEPRECIATION EXPENSE?

A. If the approved retirement end of life date were extended by ten years, the table below shows the estimated average annual decrease for 2022-2024.

Table 8

Impact of life extensions on wind projects

Plant	In-service date	Currently approved retirement	Estimated annual depreciation expense decrease
Courtenay	11-2016	11-2041	($4.2M)
Lake Benton	11-2019	11-2044	($2.1M)
Foxtail	12-2019	12-2044	($3.1M)
Blazing Star I	04-2020	04-2045	($4.0M)
Crowned Ridge	12-2020	12-2045	($3.8M)
Blazing Star II	01-2021	01-2046	($4.2M)
Freeborn	05-2021	05-2046	($4.1M)
Dakota Range	12-2021 (est)	25 yrs from ISD	($4.6M)
Northern Wind*	12-2022 (est)	25 yrs from ISD	($2.9M)*
Total			**($33.0M)**

*This decrease would be for 2023 and 2024 only since this facility is anticipated to go into service in December 2022.

Q. AT THIS TIME, HAS THE COMPANY PERFORMED ENGINEERING STUDIES TO VALIDATE THESE LIFE EXTENSIONS?

A. The Company has feasibility studies in process, which are planned to complete in early 2022.

Q. DID THE COMPANY INCORPORATE THIS POTENTIAL EXTENSION IN THIS RATE CASE?

A. No, depreciation expense and accumulated reserve balances as used to calculate the revenue requirement use the currently approved 25-year operating lives of the wind facilities. While there are indicators that longer life assumptions may be merited, we have not taken that additional step at this time. However, subject to confirmation from the feasibility studies showing a longer life is reasonable and supportable, we would be prepared to discuss further in rebuttal.

Q. HAS THE COMMISSION APPROVED 35 YEAR LIVES FOR ANY OTHER FACILITIES?

A. Yes, 35-year useful lives have been approved in the following dockets:

- Minnesota Power: Taconite Ridge I, Docket No. E-015/D-08-409, Order dated January 5, 2009.
- Minnesota Power: Bison 1- Phase 1, Docket No. E-015/D-10-223, Order dated June 29, 2010.
- Minnesota Power: Bison 1- Phase 2, Docket No. E-015/D-11-327, Order dated August 22, 2011.
- Minnesota Power: Bison 2 and Bison 3, Docket No. E-015/D-12-378, Order dated July 31, 2013.
- Minnesota Power: Bison 4, Docket No. E-015/D-14-318, Order dated January 1, 2015.
- Otter Tail Power: Langdon, Ashtabula, Luverne, and Merricourt, Docket No. E-017/D-20-703, Order dated April 21, 2021.

D. Monticello Nuclear Life Extension

Q. WHAT ARE THE COMPANY'S CURRENT PLANS FOR THE REMAINING LIFE OF THE MONTICELLO NUCLEAR PLANT?

A. The Company is currently in the process of extending the life of the Monticello nuclear generating station from 2030 to 2040. The Company has applied for a certificate of need related to additional dry fuel storage and anticipates submitting a license extension request to the NRC in 2025, with approval expected to be finalized around 2027.

Q. WHAT WOULD BE THE APPROXIMATE IMPACT TO DEPRECIATION IF THIS LIFE EXTENSION WERE APPROVED AND ABLE TO BE IMPLEMENTED AS OF JANUARY 1, 2022 AS PART OF THIS CASE?

A. If this were to be implemented in 2022 as part of this case, the impact to deprecation would be a decrease of approximately $44 million for 2022.

Q. WHAT IMPACT WOULD THE EXTENSION HAVE ON THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. Please refer to Table 1 above. In our direct case, we have used the currently approved retirement date to set rates.

E. Sherco Unit 3 and Allen S. King Plant Early Retirement

Q. WHAT ARE THE CURRENTLY APPROVED END OF LIFE DATES FOR SHERCO UNIT 3 AND THE ALLEN S. KING (KING) PLANT?

A. Currently, Sherco Unit 3 has an approved accounting end of life date of December 31, 2034. The King plant has an approved accounting end of life date of June 30, 2037.

Q. ARE PLANS BEING CONSIDERED TO CHANGE THIS RETIREMENT DATE?

A. Yes. The Company has proposed early retirement of both these facilities in the pending IRP. Sherco Unit 3 would retire at the end of 2030 and King would retire at the end of 2028.

Q. WHAT WOULD BE THE APPROXIMATE IMPACT TO DEPRECIATION IF THESE EARLY RETIREMENTS WERE APPROVED AND ABLE TO BE IMPLEMENTED AS OF JANUARY 1, 2022 AS PART OF THIS CASE?

A. If this were to be implemented in 2022 as part of this case, the impact to deprecation would be an increase of approximately $10 million for 2022 for Sherco Unit 3 and $33 million for King.

F. Luverne Wind2Battery asset

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to address concerns raised during the Company's 2020 Annual Review of Remaining Lives filing on whether the costs associated with the removal of the Luverne Wind2Battery pilot should be recoverable through rates either individually or by way of a depreciation reserve reallocation.

Q. WHAT IS THE BACKGROUND OF THE WIND2BATTERY PROJECT?

A. The project was an experimental initiative taken on by the Company to assess the utilization of battery storage in conjunction with wind production facilities to store output from the facilities and discharge those batteries to stabilize output.

Q. DID THE COMPANY COMMUNICATE THE EXPERIMENTAL NATURE OF THIS PROJECT?

A. Yes. This project was originally partially funded through an approved $1,000,000 grant from the Company's Renewable Development Fund (RDF). The RDF Grant was used to evaluate the application of sodium-sulfur battery technology – one of the very first such uses of the technology at utility-scale – as a solution to store wind energy. Focus areas for the research involved understanding how storage could improve wind farm economies and understand how storage could improve utility integration of wind resources. Xcel Energy partnered with several companies during the research of the project: NGK Insulators, S&C Electric, Minwind Energy, University of Minnesota, National Renewable Energy Laboratory, Great Plains Institute, GridPoint, and Electric Power Research Institute. The Company's investment in the Wind2Battery Project was approved and deemed eligible for recovery in the RES Rider in the Commission's September 14, 2009 Order in Docket No. E002/AI-09-379.

Q. WAS THE PILOT PROJECT SUCCESSFUL?

A. Yes, as the first use of direct wind energy storage technology in the United States, the project provided many benefits. A comprehensive report on the battery project was issued as part of the Renewable Development Fund in December 2011.[6] The report stated,

> *"The Company, the utility industry, the wind energy industry, and the energy storage industry (nationally and internationally) have all benefited from the information*

[6] This Report was included as Attachment B to the Company's 2011 Renewable Energy Standard Rider & 2010 RES Tracker Report Petition filed on October 5, 2010 in Docket No. E002/M-10-1066.

> *gained from this project…Our learnings have reached the world. We have shared our learnings with industry, governments, and academia through over 30 speaking engagements, three published reports and countless outside inquiries."*

Different modes of operation were tested for basic generation storage, economic dispatch, frequency regulation, wind smoothing and wind leveling. The testing results showed that, overall, the battery met expectations by performing successfully in all modes.

Q. WHAT CONCERNS WERE RAISED IN THE 2020 REMAINING LIVES PROCEEDING?

A. The Department of Commerce raised concerns the dismantling costs should not be recoverable because the Company failed to reserve for these assets over the useful life of the asset and did not include the assets in the 2010 or 2015 dismantling studies.

Q. DID THE COMPANY ASSESS REMOVAL COSTS OVER THE LIFE OF THIS PROJECT?

A. Yes. At inception, the Company worked with the battery manufacturer to understand the removal and disposal process and costs. The December 2011 RDF report referenced above stated, **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]

Q. WHAT WAS THE CONCLUSION OF THIS ANALYSIS?

A. The conclusion was the net cost of disposal would approximate the value of materials recovered from the battery and there would be no material net cost or removal resulting from the end-of-life removal and disposal of the battery.

Q. WHAT HAPPENED SINCE THAT INITIAL ASSESSMENT?

A. Since that time, the Company has performed three comprehensive dismantling studies (2010, 2015, and 2020) focused predominantly on our coal and natural gas-powered generating units. Each of these studies were performed by TLG Services. The 2010 Dismantling Study was completed by TLG in December 2009 – the same month when the Wind2Battery asset went into service. At that time, as discussed above, the consensus at the Company and in the industry was that battery recycling options would be in place in the future to mitigate the disposal costs.

In the 2015 Dismantling Study, the battery asset was not included for several reasons. First, the fact patterns as analyzed above had not changed. Both disposal costs and salvage from recycling were unknown and were presumed to negate each other. Second, the cost of the battery asset as compared to most other elements of the Company's electric production generating fleet was not large enough to warrant the additional cost of having TLG perform a specialized cost estimate for it. The battery represented $4 million out of a $4.2 *billion* portfolio of Steam, Hydro, and Other Production portfolio at the beginning of 2015. In other words, the battery represented less than 0.1% of our portfolio at the time, so it made more sense to focus the efforts on our coal and natural gas estimates in order to set depreciation at the appropriate levels. Third, TLG does not provide estimates for these types of batteries. They currently are looking to explore that area as an addition to their portfolio, but it was not something they could do at the time of the study.

In late 2018, the Company was verbally notified by vendors that the battery and control system were entering legacy status. Parts would no longer be manufactured for installation, and technical support would be limited going forward. In 2019, we reached out to the battery manufacture and their United States-side representative to work through disposal options. The representative contacted at least a dozen recycling facilities and was unable to find a company willing to accept the battery. The result of this process was that there are no current recycling options, and the representative provided us with information supporting an estimate of removal costs at $5.6 million if a recycling option were available. Since these actions were in place, the battery was not included in the 2020 Dismantling Study due to these separate specific investigations. The Company disclosed these facts in the 2020 Remaining Lives docket, which was the first filing available after the new facts were discovered. Dismantling costs for the pilot were presented as soon as practical and available to the Company. The Company acted prudently and in accordance with the observable facts known at each step in the process. Dismantling estimates are exactly that - *estimates* - and we should not be punished for not forecasting future events with 100% accuracy. Rather, it should be evaluated as to whether our actions and procedures are reasonable – which the timeline shows we were.

Q. IS THIS THIS INCREASE THE RESULT A FAILURE BY THE COMPANY TO DO A PROPER ANALYSIS?

A. No. The Company entered into the contract with what it believed was a viable path to disposal of the asset at negligible net cost. The subsequent change in technology and the fact that a recycling market never materialized forced the Company to reassess.

Q. SHOULD THE COMPANY HAVE BEEN ABLE TO PREDICT AND UPDATE THIS THROUGH NORMAL DISMANTLING STUDIES?

A. No. This was experimental equipment not within the scope of expertise of the Company's currently used firms that produce dismantling studies. This lack of expertise was further confirmed when the Company performed deeper analysis as part of the 2020 Dismantling study.

Q. HOW DOES THIS PILOT BATTERY PROJECT COMPARE TO OTHER ASSETS WITHIN THE DISMANTLING STUDY?

A. The battery is different from most other assets analyzed within the dismantling study due to its short life as well as the fact that it is new technology with a very uncertain future. Most other plants within the dismantling study are coal or natural gas fired units which can have a 40-80+ year operating life, giving the Company a much longer runway to estimate the removal costs and collect from customers. In comparison, the battery's initial life was only 15 years. Additionally, coal and natural gas units have many other comparative data points that can be used as a historical trend of the costs to dismantle these units from other utility companies operating in similar conditions in the United States. Given this groundbreaking project to test cutting-edge technology (the Company was the first one in the U.S. to use direct wind energy storage technology, and this was one of the first ten installations of sodium-sulfur batteries in the U.S.), there was not, and still is not to this day, any comparative data points for dismantling costs on this type of battery.

We perform dismantling studies to estimate the total future cost of dismantling and allocate it in a systematic and rational manner over the life of the asset. We will never be 100% accurate with any plant until we get into actually planning, bidding, and performing removal and thus, adjustments will need to be made close to the end of life to account for known conditions at the time. If the Commission does not allow for these types of adjustments at the end of life, it would inadvertently incentivize utilities to try to inflate their dismantling estimates over time to ensure there is always an overage rather than reasonably estimating costs and then truing them up to actuals.

Q. WHAT DO YOU PROPOSE RELATED TO THIS ASSET?

A. The Company proposes to perform a reserve reallocation to have the least impact to customers. This reallocation would shift reserves from the remaining Other Production plants and move it to the battery. Various reserve reallocations have been approved in several dockets including E,G002/D-19-723 and E,G002/D-12-151. The reallocation was calculated using a weighted average of forecasted plant balances at December 31, 2021.

Table 9

Proposed Reserve Reallocation

Plant or Unit	**Reserve reallocation**		**Plant or Unit**	**Reserve reallocation**
Angus C. Anson Unit 2 & 3	$(107,100)		Foxtail Wind	$(270,282)
Angus C. Anson Unit 4	(43,894)		Freeborn Wind	(369,878)
Black Dog Unit 5	(273,750)		Grand Meadow Wind	(229,262)
Black Dog Unit 6	(116,045)		High Bridge	(463,338)
Blazing Star I	(348,298)		Inver Hills	(66,305)
Blazing Star II	(382,828)		Jeffers Wind	(48,294)
Blue Lake Units 1 thru 4	(29,171)		Lake Benton Wind	(182,280)
Blue Lake Units 7 & 8	(86,658)		Mower Wind	(235,555)
Border Winds	(299,776)		Nobles Wind	(583,502)
Community Wind North	(34,027)		Pleasant Valley Wind	(376,334)
Courtenay Wind	(319,054)		Riverside	(383,875)
Crowned Ridge Wind	(350,494)		Wind-to-Battery System	5,600,000
Total				**$0**

The reallocation would come from FERC 344 Generators and go to the battery in FERC 348 Energy Storage all within the Electric Other Production functional class. If the reallocation were performed as of January 1, 2022, depreciation expense would increase by $0.3 million in 2022. This increase was removed from interim rates as ordered in Order Point 5 from the 2020 Remaining Lives docket. Should actual dismantling costs of the battery be less than the initial estimated $5.6 million, the Company would propose to reallocate the remaining reserve back to the groups it came from in a future docket.

Q. THE DEPARTMENT HAS BROUGHT UP CONCERNS THAT A RESERVE REALLOCATION MAY CAUSE INTERGENERATIONAL INEQUITY. HOW DO YOU RESPOND TO THIS CONCERN?

A. The purpose of this wind to battery storage asset was predominantly as an experimental research pilot project meant to serve as education to inform future battery storage solutions. It was not meant to benefit only the customers who were paying rates at the exact same period in which the battery was in operation. The research and learning opportunities afforded by this innovative pilot program will benefit many generations to come. Therefore, it is reasonable for the modest expense increase caused by the reallocation to be shared by these customers who are benefited by this project.

Q. IF THE RESERVE REALLOCATION IS NOT APPROVED BY THE COMMISSION, WHAT IMPACT WILL THAT HAVE ON THE COMPANY?

A. If a reserve reallocation is not approved, the Company will have to expense the cost of disposing of the battery with no recovery. This is inappropriate given the pilot was a widely accoladed success and we have and continue to undertake significant efforts to find a way to safely and cost effectively dispose of the asset. The Company has been a leader in clean energy development in the country, and is passionate about new technologies that provide its customers with social benefits of less air pollution and improved public health. The benefits of the Company's contributions to advancing the current state of clean energy technology can extend beyond the benefits to the Company's customers by helping to further the state of Minnesota's greenhouse gas goals. With the Company launching innovative pilots concerning electric vehicles and advanced meters, a decision denying recovery of removal costs here could send a chilling message to the Company regarding future pilot or exploratory projects. This type of experimental project is critical to the Company achieving its 100 percent carbon free by 2050 goal as current technology is not capable of supporting a zero-carbon system.

Q. IF THE COMMISSION DOES NOT APPROVE THE RESERVE REALLOCATION, WHAT ALTERNATIVES SHOULD IT CONSIDER?

A. As discussed further in Company Witness Mr. Randy A. Capra's Direct Testimony, the Company is currently pursuing multiple channels of potential disposal options. Until such time as a final quote is obtained, outright dismissal of recovery of costs regardless of what the final actual costs are places undue burden upon the Company. Since the $5.6 million is an initial estimate, the Commission could approve the Company's placement of the actual dismantling costs into a regulatory asset and request amortization of the asset in the next rate case following the dismantlement. Regulatory asset treatment of actual costs would help assuage both parties and would give the Commission a full record from inception to removal to determine if the Company acted in a prudent and reasonable manner given the facts known at that time.

VI. DEPRECIATION FOR TD&G ASSETS

A. Five-Year TD&G Depreciation Study

Q. WHAT IS A TD&G DEPRECIATION STUDY AND WHY IS IT PERFORMED?

A. Every five years, the Commission requires the Company to perform a comprehensive depreciation study. The study is an analysis of annual depreciation for TD&G depreciable plant in service as of a certain date. The Depreciation Study recommends new depreciation rates for Transmission Plant, Distribution Plant, and General Plant based on average life calculations and net salvage rates.

Q. WHEN DID THE COMPANY LAST PERFORM A TD&G DEPRECIATION STUDY?

A. The last study was completed in 2017 and filed with the Commission on July 31, 2017 in Docket No. E,G002/D-17-581 (the 2017 TD&G Depreciation Study). The Commission issued its Order on this docket on May 4, 2018. The next comprehensive five-year TD&G Depreciation Study will be filed by July 31, 2022.

Q. WHAT IS THE PROCESS FOR CONDUCTING A TD&G DEPRECIATION STUDY?

A. The Depreciation Study encompasses four distinct phases. The first phase involves data collection and field interviews. The second phase is an initial data analysis. The third phase evaluates the information and analysis. Finally, the fourth phase involves the calculation of depreciation rates and documents the corresponding recommendations.

Q. PLEASE GENERALLY DESCRIBE THE 2017 TD&G DEPRECIATION STUDY.

A. In aggregate, the study supported longer average service lives to better reflect the expected useful lives of our assets, and net salvage rates became more negative to better reflect the expected higher costs of removal. We also requested a change from using average service lives (ASL) to using an average remaining life (ARL) rate for all electric, natural gas and common assets. This change in depreciation method was proposed for the purpose of eliminating the difference between the actual accumulated depreciation reserve and the theoretical accumulated depreciation reserve balances over the remaining lives of the assets, incremental to the adjustment made in previous rate proceedings. The proposed change in depreciation lives and rates as well as the change in methodology from ASL rates to ARL rates was accepted by the Commission.

Q. DO YOU ANTICIPATE ANY NEW ASSETS IN THE NEXT STUDY?

A. Yes, there will be new assets that are currently being used in electric vehicle pilots.[7] There is approximately $174 million of expenditures in 2022-2024 for the Minnesota Electric Vehicle Program.[8] The rate case used a ten percent depreciation rate and a net salvage rate of zero percent for these assets, charging stations, wiring between meter and charging station, and the charger, as approved in Docket No. E,G002/D-20-635.

Additionally, there will be new categories or subcategories of assets related to the Company's AGIS initiatives, such as Advanced Metering Infrastructure AMI meters or Field Area Network equipment.

Q. WHAT CHANGES DOES THE COMPANY FORESEE RESULTING FROM ITS NEXT FILING?

A. Currently, we do not foresee changes in the current average service lives and net salvage rates outside of the electric vehicle and AGIS-related assets.

B. Annual TD&G Compliance Filing

Q. WHAT IMPACT DID CHANGING FROM AN ASL METHOD TO AN ARL METHOD IN THE 2017 TD&G DEPRECIATION STUDY HAVE ON COMPLIANCE FILINGS?

[7] Docket No. E999/CI-17-879 In the Matter of Commission Inquiry into Electric Vehicle Charging and Infrastructure

[8] This amount includes $150 million in electric vehicle purchase rebates, which was the initial rebate amount associated with the Company's proposed EV Purchase Rebate Program. That program is currently before the Commission. As described in greater detail in the testimony of Company witness Kelly A. Bloch, the Company anticipates that expenditures associated with the Electric Vehicle Program may change as a result of the Company's agreement, in response to stakeholder comments, to reduce the initial scope of its electric vehicle rebate offering from that initial proposal. We will make any needed adjustments to this amount in rebuttal testimony.

A. By changing to an ARL method, the Company must annually submit an update to the remaining lives and depreciation rates for TD&G plant. The first annual update was filed July 31, 2018 in Docket No. E,G002/D-18-523 and the Commission Order was issued on February 19, 2019. The second annual compliance filing was made July 31, 2019 in Docket No. E,G002/D-19-490 and the Commission Order was issued on December 13, 2019. The third annual compliance filing was made July 31, 2020 in Docket No. E,G002/D-20-635 and the Commission Order was issued on March 24, 2021. The fourth annual compliance filing was made July 29, 2021 in Docket No. E,G002/D-21-584 and is pending before the Commission.

Q. WHAT IS THE IMPACT TO DEPRECIATION EXPENSE RELATED TO DOCKET NO. E,G002/D-21-584?

A. The new depreciation rates as proposed in the compliance filing would increase Total Company depreciation expense by $0.7 million. We have proposed the new rates be effective as of January 1, 2022. The 2021 Petition is still pending final approval. However, the Test Year calculations assume this filing will be adopted in its entirety. To the extent these rates are not adopted per the filing, the Company will submit updates in rebuttal testimony.

Q. WERE THERE ANY OTHER CHANGES TO THE COMPANY'S PROCESSES PROPOSED IN DOCKET NO. E,G002/D-21-584 WHICH WOULD IMPACT DEPRECIATION?

A. No.

Q. IS THE COMPANY RECOMMENDING ANY OTHER CHANGES TO AVERAGE SERVICE LIVES OR NET SALVAGE PERCENTAGES FOR TD&G ASSETS IN THIS FILING?

A. No.

C. Regulatory Asset for TD&G Theoretical Reserve Adjustments

Q. WHAT IS A THEORETICAL RESERVE SURPLUS?

A. A theoretical reserve is calculated by determining what the depreciation reserve would be at a point in time, if the current information and assumptions about the life, salvage, and cost of removal had been known since the beginning of each asset's life. If the theoretical reserve is lower than the actual book depreciation reserve, it results in a theoretical reserve surplus. It is possible for the opposite to be true – for the theoretical reserve to be higher than the actual book depreciation reserve, resulting in a theoretical reserve deficiency.

Q. PLEASE DESCRIBE THE TREATMENT OF THE COMPANY'S THEORETICAL RESERVE AS ORDERED THROUGH RECENT RATE CASES.

A. In the 2012 TD&G Depreciation Study in Docket No. E002/D-12-858 (2012 TD&G Study), the theoretical reserve was lower than the actual book depreciation reserve, resulting in a theoretical reserve surplus. The filing presented a total Company view of the theoretical reserve surplus of $311.3 million. The Minnesota jurisdictional amount of the theoretical reserve surplus was $261.2 million. The Company was ordered in Docket No. E002/GR-12-961 to spread the surplus over eight years to reduce depreciation expense. This negative depreciation expense was referred to as the amortization of the theoretical reserve surplus.

In its 2013 Rate Case, which used a 2014 test year, the Commission required the Company to reduce depreciation expense in 2014 through 2016 by the remaining Minnesota jurisdictional amount of the theoretical reserve surplus, using a declining pattern of 50 percent in 2014, 30 percent in 2015, and 20 percent in 2016. The effect of the Commission's decisions was to reduce the net depreciation expense to be recovered in retail rates in Minnesota during the period 2013 to 2016, and to create a regulatory asset to be amortized in future rates.

Q. AFTER THE ESTABLISHMENT OF THE REGULATORY ASSET WAS COMPLETE AT THE END OF 2016, HOW DID THE COMPANY ACCOUNT FOR THE THEORETICAL RESERVE IN 2017 AND BEYOND?

A. As of December 31, 2016, all the negative depreciation expense was recognized, and the regulatory asset balance totaled $261.2 million. Because part of the accumulated depreciation was sitting in a regulatory asset, we then needed to unwind the regulatory asset over the average remaining lives of the associated assets, which effectively moved the regulatory asset to accumulated depreciation. Because this unwinding simply shifted the regulatory asset to accumulated depreciation, it was both revenue and rate neutral.

In the 2017 Annual Review of Remaining Lives (Docket No. E,G002/D-17-147), the Commission approved amortization rates for the theoretical reserve regulatory asset to unwind it in its February 8, 2018 Order, effective January 1, 2017. The approval of these amortization rates did not change the approved depreciation rates, nor did it change the amount of expense calculated for ratemaking. Beginning in 2017, the amortization expense recognized using these amortization rates simply showed expense in FERC Account 407.3 Regulatory Debits and at the same time FERC Account 403 Depreciation Expense was reduced. The net effect on total depreciation expense in the revenue requirement (amortization expense is collapsed into depreciation expense for ratemaking) is zero.

Q. HOW WERE THE APPROVED AMORTIZATION RATES CALCULATED?

A. For most asset accounts, the amortization rates were calculated to amortize the regulatory assets over the average remaining life of that asset account as of the beginning of 2017. Exceptions to this were for assets with average remaining lives of less than five years as of the beginning of 2017. For those assets, the approved amortization period was five years.

Q. CAN YOU PROVIDE A SCHEDULE SHOWING THE THEORETICAL RESERVE SURPLUS REGULATORY ASSET SET-UP AND AMORTIZATION?

A. Yes. Please see Exhibit____(MPM-1), Schedule 8.

Q. IS THE COMPANY RECOMMENDING ANY CHANGES IN THIS PROCEEDING TO ADDRESS THIS THEORETICAL RESERVE REGULATORY ASSET?

A. No. The theoretical reserve regulatory asset will be unwound over the remaining lives of the related assets. This amortization was approved in the 2017 Annual Review of Remaining Lives, Docket No. E,G002/D-17-147. No further Commission action is necessary.

Q. DOES THIS AMORTIZATION OF THE REGULATORY ASSET CHANGE THE TOTAL DEPRECIATION EXPENSE RECOGNIZED IN THIS CASE?

A. No. The Company's recording of this regulatory asset is consistent with generally accepted accounting principles (GAAP) and does not affect regulatory reporting or ratemaking. The amortization expense for Minnesota regulatory purposes is still computed and booked based on the average service life depreciation rates applied to the original plant balance. The only difference is that a portion of this depreciation expense is recorded in depreciation expense, and a portion is recorded in amortization expense. In the same manner, the accumulated depreciation for Minnesota regulatory purposes consists of both accumulated depreciation and the regulatory asset. This accounting is consistent with GAAP and necessary to comply with the FERC's requirements.

D. Software as a Service

Q. WHAT TOPIC ARE YOU ADDRESSING IN THIS PART OF YOUR TESTIMONY?

A. In this section I am requesting a new regulatory mechanism that will allow the Company to effectively recover costs of technology projects as the industry goes through a change from owning software and supporting hardware to a new model focused on Software as a Service (SaaS) and other outsourced technology products. I will start by describing the changes that are occurring in the industry and the impact this has on the Company's accounting. I will then propose regulatory mechanisms that provide a reasonable model for the recovery of these costs for the Company.

Q. CAN YOU DESCRIBE THE CHANGE THAT IS CURRENTLY OCCURRING?

A. Yes. The technology market is rapidly transitioning from a model of internally hosted software to cloud based computing and SaaS. This transition is having significant impacts on the industry and the way costs are recognized and recovered.

Q. HOW HAS SOFTWARE HISTORICALLY BEEN ACQUIRED AND IMPLEMENTED?

A. Historically, software vendors sold their product through a perpetual license to use the software. Individual companies purchased these perpetual licenses and then independently contracted with other providers to acquire hardware, operating system licenses, supporting software and implementation services. The Company had primary responsibility for coordinating this implementation.

Q. HOW IS THE NEW SOFTWARE MODEL DIFFERENT THAN WHAT HAS CURRENTLY BEEN EMPLOYED?

A. In the SaaS model, there is no longer a perpetual license that is sold by the vendor. Instead, the software vendor provides access to a software environment which now runs on hardware and operating systems which they control and manage. Then the vendor charges a periodic fee to the customer to use this environment.

Q. HOW IS THE COST STRUCTURE DIFFERENT IN A SAAS MODEL?

A. The SaaS model significantly decreases the amount of costs that are considered capital while at the same time increasing the amount of periodic operating and maintenance (O&M) costs from the vendor. Additionally, the timing of these costs can vary between an internally owned and hosted software and a SaaS arrangement.

Q. HAVE THERE BEEN ANY CHANGES TO ACCOUNTING WITHIN THE INDUSTRY TO ADDRESS THIS CHANGE?

A. In 2018, FERC provided guidance that allowed utilities to treat SaaS implementation costs as intangible plant for ratemaking purposes. Since implementation costs can amount to over two thirds of the total cost of new software, this guidance was very constructive in ensuring that utilities could more consistently recover these costs through existing regulatory mechanisms and rate cases.

Q. WAS THIS CHANGE ABLE TO RESOLVE ISSUES WITH REGULATORY RECOVERY?

A. Although this change was helpful in addressing capitalization of software implementation costs, it did not address changes in other costs incurred during the software implementation and additional ongoing costs following the implementation. I mentioned implementation costs can be up to two thirds of the costs of new solutions. However, depending on the software or infrastructure being transitioned, there can still be a large amount of costs associated with implementing the software that do not meet the accounting definition of capitalizable implementation costs which create recovery challenges. These include data conversion costs, training, and periodic maintenance fees.

Q. WHAT IS THE FINANCIAL IMPACT TO THE COMPANY OF THESE CHANGES?

A. The net impact of these changes is a reduction in capital investment for the Company and offsetting increases in O&M. Drivers of this shift include the loss of the perpetual licenses, hardware, and other fixed costs which now are controlled by the vendor. The vendor then bills these costs as well as support and maintenance fees back to the Company as a periodic charge. This change can significantly increase the Company's O&M while it decreases capital.

Because there is less capital, the Company also incurs a loss in rate base and the return on assets that comes with that rate base. Return on rate base is made up of two components. First, it is a base return for the use of investor funds. Second, it provides compensation for the risk being taken on by the Company by investing in these assets. Technology assets are inherently risky to the Company as they have much higher risk of implementation failure and shorter useful lives when compared to core infrastructure like transmission lines.

Although the SaaS model has led the Company to require less investment of cash, the Company has not proportionately transferred the risk that comes with investing in technology assets.

Q. ARE THERE OTHER FINANCIAL FACTORS THAT SHOULD BE CONSIDERED IN ASSESSING THIS TRANSITION?

A. Yes. Another factor, aside from total spend incurred, is the profile of that spend. The transition from internally owned and hosted software to cloud based software creates additional volatility in operating and support costs as the Company goes through periods of paying to support and retire applications internally while also ramping up on SaaS platforms.

Another factor that influences future operating cost spend is the pricing structure from the vendor. Certain services like extracting and transferring data between applications is an ongoing relatively fixed cost for an internally hosted environment. However, an externally hosting vendor will charge incrementally based on the amount of data being transferred. There can be significant variability in costs as the Company learns how best to host and manage other integrated systems in order to minimize these costs across applications.

Q. WHAT IS THE COMPANY REQUESTING IN THIS CASE?

A. The Company is asking for a deferral of O&M costs directly associated with the SaaS implementation that will help counteract the effects of cloud-based transitions.

Q. WHY IS A FULL DEFERRAL TREATMENT OF O&M COSTS DURING IMPLEMENTATION APPROPRIATE?

A. When transitioning from an internally owned and hosted model to a SaaS model, there is a period in which the Company incurs double support costs. This is because the Company is still employing staff to support the internally hosted application until it has fully transitioned to the new software. However, the vendor begins billing full O&M support costs from the point the contract commences. This creates duplication of costs that do not occur to the same extent when replacing internally owned software with new internally owned software.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THIS?

A. The Company proposes all directly incurred O&M costs during the SaaS implementation be treated as part of the intangible software being implemented and then amortized over the expected useful life of the software. This treatment has the effect of removing some of the volatility in O&M support spend while also more equitably assigning all costs attributable to the software to the full useful life of that software.

Q. DO YOU BELIEVE THIS TREATMENT IS EQUITABLE TO BOTH THE COMPANY AND CUSTOMERS?

A. Yes. This treatment eliminates cost spikes for the Company and more appropriately assigns these costs through rates to the customers that benefit in future years.

E. Electric Meters

Q. WHAT TOPIC ARE YOU ADDRESSING IN THIS PART OF YOUR TESTIMONY?

A. In this section I am proposing a mechanism for the regulatory recovery of the electric meters that will be replaced as part of the AGIS program. The Company is currently in the process of deploying advanced AMI meters as part of the larger advanced grid initiative. The rollout of the AMI meters will lead to the early retirement of legacy meters with remaining estimated unrecovered net book value of $28 million on December 31, 2024. While the deployment is ongoing, the legacy meters will continue to depreciate.

Q. WHAT IS THE COMPANY PROPOSING FOR THE RECOVERY OF THE REMAINING BOOK VALUE ON THESE METERS?

A. The Company is proposing that any remaining book value at the time AMI meter deployment is complete will be transferred to a regulatory asset and deferred for recovery as part of the Company's next rate case.

F. Electric Vehicle (EV) Rebates

Q. WHAT TOPIC ARE YOU ADDRESSING IN THIS PART OF YOUR TESTIMONY?

A. In this section I am addressing the electric vehicle rebate program that is currently being proposed by the Company. This large rebate effort is intended to kick-start the growth of EV adoption in Minnesota. For further details on the program, please refer to Company Witness Kelly A. Bloch's direct testimony. Specifically, I will be proposing an amortization rate of the proposed regulatory asset to be set up for these rebates.

Q. WHAT HAS BEEN PROPOSED REGARDING ACCOUNTING AND COST RECOVERY OF THESE REBATES?

A. In Docket E002/M-20-745, *In The Matter Of Xcel Energy's Petition For Approval Of Electric Vehicle Programs As Part Of Its Covid-19 Pandemic Economic Recovery Investments*, the Company requested,

> *"…that the Commission grant approval to establish a regulatory asset for the cost of the rebates. Under this proposal, when the Company pays a rebate, it would be recorded as a regulatory asset and included in rate base in a future rate case, earning a return on the capitalized balance. The balance of the regulatory asset would build over time as more rebates are paid. To recover the balance of the regulatory asset, the amount would be amortized over a prescribed period. We propose that the regulatory asset be amortized over ten years.*

This docket is pending. Should the Commission order on the EV docket prior to the completion of this case, the Company would incorporate the order into the MYRP as applicable.

Q. DO YOU BELIEVE A TEN-YEAR AMORTIZATION OF THE PROPOSED REBATES IS APPROPRIATE?

A. Yes. Should the Commission approve the Company's request to record the proposed rebates to a regulatory asset, I believe amortizing the asset over ten years would be appropriate and consistent with the approved lives of other electric vehicle-supporting resources.

VII. TRIENNIAL NUCLEAR DECOMMISSIONING COSTS

Q. WHAT IS NUCLEAR DECOMMISSIONING?

A. Nuclear decommissioning is the method used to accumulate the final removal costs for the Company's three nuclear units. The amounts collected through general rates are funded externally in a trust fund per Nuclear Regulatory Commission rules. The annual accruals are calculated from a detailed engineering cost estimate to remove the plant and to store the fuel until the federal government takes possession of all the fuel assemblies.

Q. HAS THE COMMISSION RECENTLY ADDRESSED THE COMPANY'S NUCLEAR DECOMMISSIONING COSTS?

A. Due to the 2020 Stay Out, the Company was approved to delay the Commission's March 13, 2020 Order, and maintain the accrual approved in the 2014 Triennial Filing through January 1, 2022. Because the 2020 Triennial Filing recommends an accrual with updated inputs to be effective January 1, 2022, the Company used this conservative accrual option to be incorporated into this rate case. Table 1 on page 6 provides the alternative recommendations for the accrual.

Q. WHAT HAS THE COMPANY INCLUDED FOR AN ACCRUAL AMOUNT AS PART OF THIS RATE CASE?

A. The rate case currently includes an accrual of $26.9 million (Minnesota jurisdictional level), which reflects the most recently recommended accrual level included in the open 2022 – 2024 Triennial Nuclear Plant Decommissioning Study and Assumptions, Docket No. E002/M-20-855.

Q. WHEN IS THE COMPANY'S NEXT TRIENNIAL FILING?

A. The next triennial nuclear filing will be made on or before December 1, 2023.

Q. WHAT IMPACT WILL THAT FILING HAVE ON THE TEST YEAR?

A. The filing will not directly impact the 2023 test year for this case. Rates resulting from the 2023 triennial filing do not become effective until January 2025, which is outside the test year for this case.

VIII. END OF LIFE NUCLEAR FUEL ACCRUALS

Q. PLEASE EXPLAIN THE RATE CASE TREATMENT OF END OF LIFE (EOL) NUCLEAR FUEL ACCRUALS.

A. While the EOL Accrual and Decommissioning Accrual both function by setting funds aside, the EOL Accrual is different in that its funds are held within the Company. As such, there is an added offset to rate base for the EOL funds that customers receive resulting in a lower return on rate base components in general rates.

The rate base and accruals collected are put into rates in the Company's general rate case filings. At that point both are in parity – meaning that for the first year the customer pays the full accrual amount and receives the full benefit of the rate base impact through rates. However, in future years the customer needs to be compensated for the additional offset to rate base that it should receive for the contributions it has made since the general rate was approved. To compensate for this, the assumed accrual increases to an amount that includes the rate base impact the customer should receive. In this way, the customer is credited for the benefit they should receive by essentially investing the assumed return into the EOL fund balance. As such, every year that passes, the assumed accrual will increase without an increase to rates, to compensate for the assumed interest until another general rate case is filed and ordered on. At this point, the higher accrual is put into rates, offset by a larger rate base offset.

In summary, the EOL Accrual increases annually without an increase in rates in order to compensate for the assumed interest. This process resets or rebalances every time a new general rate case is filed where the rate base benefit is adjusted to reflect the past amount contributed. To illustrate this impact, Exhibit ___(MPM-1), Schedule 9 to this Testimony shows the calculated impacts and how the return on rate base is offset by the increasing accrual.

Order Point 3 of the Commission's March 13, 2020 Order in Docket No. E002/M-17-828 directed the Company to "Increase the annual end-of-life nuclear fuel accrual to $2,087,026, effective January 1, 2021." That amount is the Minnesota jurisdictionalized amount (using a 73.0558 percent factor) of the Total Company accrual of $2,856,756. This increase was delayed by Order Point 10 in the 2020 Stay Out, maintaining the $2,087,026 accrual until January 1, 2022.

IX. DEFERRED TAXES

Q. WHAT ARE DEFERRED TAXES?

A. Deferred taxes are a result of an accounting process called "normalization," which is the timing difference between book and tax accounting. The difference is then multiplied at the current tax rate to determine the current deferred tax. This amount in turn is added to the Accumulated Deferred Income Tax (ADIT) balance. Deferred taxes derive from tax depreciation being greater than book depreciation (in the early years of an assets life). Regulated utilities are required by the Internal Revenue Service (IRS) to normalize accelerated tax depreciation on plant assets (i.e., to use deferred taxes) in order to receive the benefits of accelerated tax depreciation. Thus, deferred taxes and accelerated tax depreciation go together. The Company's ADIT balance has been growing in large part due to the accumulation of bonus tax depreciation. The Company strives to maximize the tax benefits by using accelerated methods to depreciate its assets, which are taken in the early years of an asset's life. Deferred taxes, from a ratemaking perspective, allow the Company to share the early tax benefits with all customers equally over the asset's straight-line book life.

Q. PLEASE EXPLAIN WHAT "NORMALIZATION" MEANS IN THE CONTEXT OF UTILITY ACCOUNTING.

A. Normalization refers to a method of accounting in which the tax benefits associated with depreciation of utility assets are spread over the same time period that the costs of those assets are recovered from customers. For example, if rates are set based on straight-line book depreciation, the federal income tax expense included in those rates must also be calculated as though the utility used straight-line book depreciation. The difference between the federal income tax expense calculated using accelerated depreciation and the federal income tax expense calculated using straight-line book depreciation is recorded as a deferred tax liability. The cumulative deferred tax liability balance is recorded as ADIT and serves as an offset to rate base. While this discussion is based on the federal rules for timing differences related to life differences, the ADIT balance includes other plant related timing differences.

Q. HOW DOES ADIT IMPACT RATE BASE?

A. The net plant ADIT balance is a liability, and therefore it decreases the net plant portion of rate base. In general, assets are depreciated more quickly for tax purposes than for book purposes, and the timing difference between those two depreciation amounts is multiplied by the tax rate to arrive at the current deferred tax for that asset. The cumulative amount of the deferred tax expense for all assets is recorded as ADIT, and it reduces rate base on a dollar-for-dollar basis.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW ARAM IS CALCULATED.

A. As explained earlier, plant ADIT net liability balances arise primarily due to accelerated timing of tax depreciation as compared to book depreciation. When tax depreciation is greater than book depreciation, the ADIT liability balance is increasing, or "setting up." When tax depreciation is less than book depreciation, later in an asset's life, the ADIT liability balance for that asset is getting smaller, or "unwinding." ARAM is a method that calculates an average tax rate from all the tax rates used up to the point when the ADIT balance begins unwinding and uses this average tax rate to unwind the ADIT to zero.

For assets that were in service prior to the January 1, 2018 effective date of the Tax Cuts and Jobs Act (TCJA), but for which the ADIT has not yet begun unwinding, annual deferred tax expense will be calculated at the new rate, and the accumulated deferred balance will continue increasing. When the deferred tax balance stops increasing and starts decreasing, the annual deferred tax calculation will switch from using the current tax rate to using the average of the tax rates applied up to this point, which ensures that the vintage deferred record will unwind to zero over the remaining life for the vintage.

For assets that were in-service before January 1, 2018 and for which the ADIT has already begun unwinding (meaning book depreciation is greater than tax depreciation), the annual deferred tax expense calculations will never use the new federal tax rate of 21 percent. Instead, they will use an average of the composite tax rates based on the historical 35 percent federal rate to unwind their accumulated deferred balances.

Finally, for assets that are placed in-service after January 1, 2018, the deferred taxes will be calculated entirely at the new federal tax rate going forward. These assets have no excess ADIT, and thus no excess to flow back to customers. And because the Company's revenue requirement in this proceeding is based on a post-2018 test year, the deferred taxes for the 2019 – 2022 additions are calculated at the new federal tax rate.

Two examples have been provided in Exhibit ___(MPM-1), Schedule 10 to show the deferred tax expense calculation for: (1) an asset whose ADIT liability was still growing at the time of a tax rate change; and (2) an asset whose ADIT liability was already unwinding at the time of the tax rate change.

Q. DOES THE COMPANY PRESENTLY USE ARAM TO RETURN THE PLANT EXCESS ADIT BALANCE TO CUSTOMERS?

A. Yes. The TCJA contains an alternative amortization method for certain taxpayers' protected excess ADIT, that may be used if the taxpayers' books and underlying records do not contain vintage account data necessary to apply ARAM. However, NSPM maintains its utility property records with adequate vintage account data to use ARAM, and therefore does so.

Further, while there can be a small portion of plant-related excess ADIT that is not protected due to the fact that the underlying timing difference is caused by basis differences rather than book to tax depreciation differences, the Company has always amortized its plant-related excess ADIT using ARAM. This is consistent with how the Company has maintained its utility property records and is also consistent with the Company's understanding of the Commission's December 15, 2018 and January 25, 2019 Orders in Docket E,G999/CI-17-895 (Commission Investigation into the Effects on Electric and Natural Gas Utility Rates and Services of the 2017 Federal Tax Act). Specifically, while the Commission's December 15, 2018 Order speaks in terms of protected and unprotected excess ADIT, the Commission's January 25, 2019 Order noted that it was consistent with the intent of that order to categorize excess ADIT as either plant-related or non-plant-related instead of protected or unprotected. Accordingly, NSPM has used "plant" and "non-plant" for decades and continues to do so.

Q. WHAT IS THE CALCULATED AMOUNT OF ARAM AMORTIZATION FOR 2022?

A. The deferred income tax expense associated with ARAM on the excess ADIT for electric and common assets, respectively, is calculated to be $33.3 million and $3.3 million for 2022. The year-end 2021 plant excess ADIT is projected to be $810.1 million for electric assets, and $14.2 million for the common assets. These amounts are for total Company, and the common amounts have been allocated to the electric business. Under the ARAM method, however, this amortization is not a consistent, straight-line amount, but instead will vary somewhat from year-to-year based on the lives of the underlying plant assets and when assets begin their ARAM amortization.

Q. WERE THE 2021 EXCESS ADIT AND ARAM AMOUNTS USED IN THE TEST YEAR?
A. Yes, the 2021 excess ADIT and ARAM served as the starting point for the MYRP.

Q. ARE THE COMPANY'S DEFERRED TAXES IN THIS CASE CALCULATED TO COMPLY WITH ALL IRS REGULATIONS?
A. Yes.

Q. IF FEDERAL OR STATE CORPORATE TAX RATES INCREASE IN THE FUTURE, HOW WOULD YOU PROPOSE TO HANDLE THIS?
A. The Company expects an increase in tax rates would be treated in the same manner as a tax rate decrease and consistent with the recovery treatment provided under the TCJA. If tax rates change prior to the filing of rebuttal testimony, the Company will provide updates in rebuttal testimony to address the impact of the change. If rates change following the case, the Company is proposing to establish a tracker that would track any additional federal or state tax expense above the amount established in this case for future recovery. This income tax rate tracker is discussed in greater detail by Mr. Halama.

Q. WHAT IS THE COMPANY REQUESTING IN THIS CASE FOR DEFERRED TAXES?
A. The Company is requesting approval from the Commission that future tax rate changes enacted between rate cases will be treated consistent with past treatment of TCJA.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.
A. I recommend the Commission approve the amounts the Company has calculated for the forecast depreciation in this proceeding, consistent with my testimony above.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
A. Yes, it does.

Statement of Qualifications

Mark P. Moeller
Director, Capital Asset Accounting
401 Nicollet Mall, Minneapolis, Minnesota

Current Responsibilities:

My current position with Xcel Energy Services (XES) is Director, Capital Asset Accounting. I am responsible for:

- Capital investment cost recovery process, which includes the development of detailed actuarial analysis, regulatory filings with the various state and federal rate regulatory commissions, and expert testimony to support recovery levels in rate proceedings;
- Accounting for and reporting on the nuclear plant decommissioning funding process, which includes the development of detailed engineering cost studies combined with a complete financial and economic analysis to develop detailed regulatory filings to establish the ratepayer funding levels necessary to accumulate the total future decommissioning cost requirement;
- Plant asset-related ratemaking process, which supports the rate filings for all of the Xcel Energy Operating Companies' retail and wholesale jurisdictions; and
- Overseeing capital asset reporting including internal reporting as well as external report to meet SEC, FERC, IRS and state specific filing requirements
- Capitalization policy, including policy development, interpretation and alignment with GAAP and FERC principles and requirements.

Previous Experience:

I have worked for Xcel Energy since 2003 and held various financial management roles in financial controls, corporate accounting, internal reporting and process improvement.

Education:

I received a Bachelor of Science degree with a major accounting, from Saint John's University in 1989. I received an Masters of Business Administration degree from the University of Minnesota Carlson School of Management in 1996.

Northern States Power Company
Roll Forward by Functional Class
CWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 1 of 36

	2021											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
CWIP Beginning Balance	24,225,577	25,817,625	28,823,274	33,002,236	32,600,141	35,967,337	36,189,880	37,180,353	38,965,882	36,755,469	40,142,849	43,341,310
CWIP Expenditures	1,801,213	2,911,636	4,035,010	3,445,496	3,423,302	4,670,118	3,866,644	5,246,283	4,635,393	3,305,859	3,084,823	9,454,762
AFUDC Debt	31,846	47,745	49,200	52,900	56,038	58,997	59,864	61,199	59,684	59,683	64,190	58,928
AFUDC Equity	74,359	115,283	117,361	126,197	133,624	140,693	142,761	145,946	142,332	142,330	153,078	140,530
Closings to Plant	(315,370)	(69,016)	(22,609)	(4,026,688)	(245,768)	(4,647,265)	(3,078,796)	(3,667,899)	(7,047,823)	(120,492)	(103,630)	(22,451,852)
Electric Intangible CWIP	25,817,625	28,823,274	33,002,236	32,600,141	35,967,337	36,189,880	37,180,353	38,965,882	36,755,469	40,142,849	43,341,310	30,543,678
Electric Steam Production Plant												
CWIP Beginning Balance	10,427,892	13,065,981	14,176,751	15,817,317	14,769,658	12,638,940	14,297,138	15,603,781	18,632,525	9,672,684	9,415,697	6,683,126
CWIP Expenditures	2,726,970	1,444,442	2,845,856	2,956,396	2,119,710	1,980,881	2,463,707	3,522,140	4,306,212	3,416,554	2,303,670	1,075,015
AFUDC Debt	16,181	23,705	24,178	24,266	22,017	21,262	24,310	27,893	23,776	15,912	13,381	10,442
AFUDC Equity	37,781	57,348	57,674	57,878	52,500	50,705	57,974	66,519	56,700	37,946	31,911	24,901
Closings to Plant	(142,843)	(414,726)	(1,287,142)	(4,086,199)	(4,324,946)	(394,650)	(1,239,348)	(587,809)	(13,346,528)	(3,727,398)	(5,081,533)	(1,828,445)
Electric Steam Production CWIP	13,065,981	14,176,751	15,817,317	14,769,658	12,638,940	14,297,138	15,603,781	18,632,525	9,672,684	9,415,697	6,683,126	5,965,038
Electric Nuclear Production Plant												
CWIP Beginning Balance	47,050,655	51,974,303	57,859,127	62,242,867	68,166,076	51,927,668	56,633,496	60,724,971	66,887,284	60,341,520	60,819,035	59,940,567
CWIP Expenditures	5,567,386	5,783,255	4,601,238	15,797,959	8,011,954	5,374,352	9,375,080	8,942,458	10,222,674	9,748,744	5,706,849	5,647,718
AFUDC Debt	65,144	93,205	92,416	101,168	95,503	82,291	96,079	104,487	104,792	100,371	99,084	94,172
AFUDC Equity	152,110	225,290	220,452	241,341	227,729	196,247	229,124	249,176	249,904	239,360	236,291	224,577
Closings to Plant	(860,992)	(216,926)	(530,366)	(10,217,259)	(24,573,594)	(947,062)	(5,608,808)	(3,133,807)	(17,123,134)	(9,610,960)	(6,920,692)	(10,952,213)
Electric Nuclear Production CWIP	51,974,303	57,859,127	62,242,867	68,166,076	51,927,668	56,633,496	60,724,971	66,887,284	60,341,520	60,819,035	59,940,567	54,954,821
Electric Hydro Production Plant												
CWIP Beginning Balance	219,948	223,628	228,385	241,114	247,495	263,867	275,695	239,317	281,980	294,840	301,697	243,070
CWIP Expenditures	9,510	11,276	10,990	5,029	14,956	10,334	6,667	41,667	11,667	6,667	3,667	1,667
AFUDC Debt	314	415	385	399	418	441	385	426	472	488	446	400
AFUDC Equity	734	1,004	919	953	998	1,052	918	1,017	1,125	1,163	1,065	953
Closings to Plant	(6,879)	(7,937)	435	-	-	-	(44,349)	(447)	(404)	(1,461)	(63,805)	(597)
Electric Hydro Production CWIP	223,628	228,385	241,114	247,495	263,867	275,695	239,317	281,980	294,840	301,697	243,070	245,493
Electric Other Production Plant												
CWIP Beginning Balance	759,616,067	451,320,312	491,994,417	489,074,818	501,472,649	244,696,195	319,067,242	378,291,229	407,933,197	479,752,126	485,981,815	535,638,805
CWIP Expenditures	17,164,125	45,494,902	219,517,249	14,007,488	62,862,107	90,875,825	61,135,757	39,442,563	74,928,214	15,549,846	50,549,177	20,606,782
AFUDC Debt	851,484	908,817	800,725	803,513	609,372	443,755	532,624	606,448	689,301	753,890	799,026	532,194
AFUDC Equity	1,988,280	2,204,388	1,910,189	1,916,856	1,453,016	1,058,247	1,270,178	1,446,230	1,643,816	1,797,845	1,905,482	1,269,154
Closings to Plant	(328,299,645)	(7,934,002)	(225,147,762)	(4,330,028)	(321,700,949)	(18,006,779)	(3,714,573)	(11,853,273)	(5,442,402)	(11,871,892)	(3,596,695)	(401,046,107)
Electric Other Production CWIP	451,320,312	491,994,417	489,074,818	501,472,649	244,696,195	319,067,242	378,291,229	407,933,197	479,752,126	485,981,815	535,638,805	157,000,829
Electric Transmission Plant												
CWIP Beginning Balance	108,907,411	97,706,608	110,481,138	128,307,485	137,795,119	120,684,280	131,383,212	137,201,709	155,135,940	164,870,988	170,976,575	182,316,753
CWIP Expenditures	12,975,785	13,971,269	32,968,686	13,018,059	14,861,313	19,945,167	20,699,427	21,964,256	28,258,362	17,665,196	16,146,440	16,917,654
AFUDC Debt	115,121	153,000	178,126	167,691	196,841	202,172	217,032	238,775	261,936	273,900	289,136	176,427
AFUDC Equity	268,805	373,157	424,931	410,614	469,455	482,130	517,568	569,420	624,654	653,185	689,520	420,736
Closings to Plant	(24,560,513)	(1,722,895)	(15,745,396)	(4,108,730)	(32,638,448)	(9,930,535)	(15,615,530)	(4,838,220)	(19,409,904)	(12,486,694)	(5,784,919)	(168,932,206)
Electric Transmission CWIP	97,706,608	110,481,138	128,307,485	137,795,119	120,684,280	131,383,212	137,201,709	155,135,940	164,870,988	170,976,575	182,316,753	30,899,364
Electric Distribution Plant (1)												
CWIP Beginning Balance	59,872,748	63,567,201	68,022,213	73,556,884	66,405,647	69,801,057	58,409,830	67,201,478	76,146,484	80,730,369	85,410,517	93,213,226
CWIP Expenditures	20,651,019	19,073,484	17,448,277	19,522,500	23,657,264	3,516,189	30,200,437	31,982,932	29,290,766	29,437,576	29,794,383	38,036,337
AFUDC Debt	82,923	108,951	100,864	101,452	99,243	97,574	112,404	115,151	118,104	122,116	129,546	89,685
AFUDC Equity	193,244	264,552	240,759	242,050	236,717	232,697	268,057	274,608	281,649	291,216	308,935	213,878
Closings to Plant	(17,232,733)	(14,991,975)	(12,255,229)	(27,017,238)	(20,597,815)	(15,237,687)	(21,789,250)	(23,427,685)	(25,106,632)	(25,170,759)	(22,430,156)	(82,845,565)
Electric Distribution CWIP	63,567,201	68,022,213	73,556,884	66,405,647	69,801,057	58,409,830	67,201,478	76,146,484	80,730,369	85,410,517	93,213,226	48,707,560
Electric General Plant												
CWIP Beginning Balance	68,301,658	68,961,132	72,327,574	76,118,359	35,624,474	37,215,577	37,086,770	33,883,560	39,023,571	46,243,697	51,000,058	47,701,423
CWIP Expenditures	3,484,652	4,292,978	11,086,210	5,945,787	5,374,470	8,124,481	6,959,058	8,285,928	12,509,196	11,033,585	6,467,730	9,323,090
AFUDC Debt	78,678	103,801	93,720	84,130	27,828	28,534	33,068	37,785	42,670	45,502	46,966	45,612
AFUDC Equity	183,711	251,240	224,049	200,664	66,344	68,048	78,858	90,108	101,758	108,511	112,003	108,773
Closings to Plant	(3,087,568)	(1,281,578)	(7,613,195)	(46,724,466)	(3,877,539)	(8,349,869)	(10,274,195)	(3,273,810)	(5,433,498)	(6,431,238)	(9,925,335)	(21,654,051)
Electric General CWIP	68,961,132	72,327,574	76,118,359	35,624,474	37,215,577	37,086,770	33,883,560	39,023,571	46,243,697	51,000,058	47,701,423	35,524,846
Total Electric Utility	772,636,791	843,912,878	878,361,079	857,081,259	573,194,919	653,343,265	730,326,397	803,006,863	878,661,693	904,048,244	969,078,280	363,841,629

Northern States Power Company
Roll Forward by Functional Class
CWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 2 of 36

	2021											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
CWIP Beginning Balance	48,806,914	56,667,269	56,820,167	57,340,757	63,193,647	67,622,486	70,391,943	74,442,728	82,722,631	87,345,604	95,291,353	94,104,186
CWIP Expenditures	9,514,059	6,540,611	2,092,968	6,213,970	5,727,701	2,662,367	10,355,616	8,565,134	11,302,560	11,274,279	6,676,005	8,414,254
AFUDC Debt	71,741	99,793	90,886	95,604	103,786	110,695	108,516	117,470	125,932	132,463	137,027	87,655
AFUDC Equity	167,512	241,311	216,812	228,070	247,481	263,981	258,784	280,136	300,317	315,893	326,777	209,035
Closings to Plant	(1,892,956)	(6,728,817)	(1,880,076)	(684,753)	(1,650,129)	(267,586)	(6,672,131)	(682,837)	(7,105,837)	(3,776,885)	(8,326,977)	(82,287,536)
Common Intangible CWIP	56,667,269	56,820,167	57,340,757	63,193,647	67,622,486	70,391,943	74,442,728	82,722,631	87,345,604	95,291,353	94,104,186	20,527,593
Common General Plant												
CWIP Beginning Balance	26,212,851	27,550,689	30,843,973	32,126,451	34,263,658	38,721,210	40,951,188	41,495,917	46,465,524	48,159,978	54,232,881	57,834,704
CWIP Expenditures	2,569,772	3,735,091	4,412,491	2,267,509	4,515,436	4,354,945	6,928,537	7,782,072	12,309,502	7,433,555	10,343,278	16,633,452
AFUDC Debt	18,714	25,948	24,608	25,311	26,253	29,641	32,217	34,658	39,000	46,276	55,896	62,266
AFUDC Equity	43,696	62,747	58,703	60,381	62,602	70,686	76,830	82,650	93,004	110,358	133,298	148,489
Closings to Plant	(1,294,344)	(530,501)	(3,213,324)	(215,994)	(146,739)	(2,225,293)	(6,492,856)	(2,929,773)	(10,747,052)	(1,517,286)	(6,930,650)	(31,805,678)
Common General CWIP	27,550,689	30,843,973	32,126,451	34,263,658	38,721,210	40,951,188	41,495,917	46,465,524	48,159,978	54,232,881	57,834,704	42,873,232
Total Common Utility	84,217,958	87,664,140	89,467,208	97,457,305	106,343,696	111,343,131	115,938,645	129,188,155	135,505,582	149,524,235	151,938,890	63,400,825
Nuclear Fuel												
CWIP Beginning Balance	135,797,133	136,805,540	138,122,923	138,946,709	140,566,958	142,300,330	149,289,788	154,797,848	156,514,762	86,105,117	86,617,577	87,132,996
CWIP Expenditures	364,011	453,401	73,889,518	877,263	958,427	6,188,195	4,666,401	855,257	1,637,409	548,398	34,509	14,212,964
AFUDC Debt	193,226	252,601	258,955	228,428	231,443	238,437	248,662	254,570	224,100	141,241	142,081	154,553
AFUDC Equity	451,179	611,381	617,712	544,958	551,881	568,613	592,998	607,087	534,424	336,824	338,829	368,571
Closings to Plant	(10)	-	(73,942,400)	(30,400)	(8,377)	(5,787)	-	-	(72,805,578)	(514,003)	-	-
Nuclear Fuel CWIP	136,805,540	138,122,923	138,946,709	140,566,958	142,300,330	149,289,788	154,797,848	156,514,762	86,105,117	86,617,577	87,132,996	101,869,084
Total Nuclear Fuel	136,805,540	138,122,923	138,946,709	140,566,958	142,300,330	149,289,788	154,797,848	156,514,762	86,105,117	86,617,577	87,132,996	101,869,084
Total Electric, Common, and Nuclear Fuel	**993,660,289**	**1,069,699,941**	**1,106,774,996**	**1,095,105,521**	**821,838,945**	**913,976,184**	**1,001,062,891**	**1,088,709,780**	**1,100,272,393**	**1,140,190,056**	**1,208,150,166**	**529,111,538**

Footnotes:
(1) Electric Distribution Plant in the schedule above contains NSPM total company all jurisdictions. Below is the Electric Distribution State of MN only

	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN located only												
CWIP Beginning Balance	53,105,178	59,243,515	64,215,965	69,191,043	61,982,758	64,041,245	52,184,572	61,726,387	69,422,171	73,317,861	77,644,775	83,699,525
CWIP Expenditures	19,534,907	18,005,564	15,645,384	17,610,170	21,128,933	539,194	26,455,570	27,521,698	25,137,957	25,199,132	25,129,041	33,616,892
AFUDC Debt	80,653	106,228	98,150	98,498	95,518	93,902	108,129	111,304	113,873	117,445	123,351	81,235
AFUDC Equity	187,944	257,953	234,286	235,003	227,834	223,939	257,860	265,434	271,560	280,077	294,162	193,725
Closings to Plant	(13,665,168)	(13,397,294)	(11,002,742)	(25,151,955)	(19,393,799)	(12,713,709)	(17,279,743)	(20,202,652)	(21,627,701)	(21,269,741)	(19,491,804)	(79,104,759)
Electric Distribution CWIP (MN Only)	59,243,515	64,215,965	69,191,043	61,982,758	64,041,245	52,184,572	61,726,387	69,422,171	73,317,861	77,644,775	83,699,525	38,486,617

Northern States Power Company
Roll Forward by Functional Class
CWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 3 of 36

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
CWIP Beginning Balance	30,543,678	33,571,078	39,074,233	40,000,120	39,585,621	41,583,263	42,801,015	44,960,896	47,300,967	49,440,527	52,534,221	55,386,439
CWIP Expenditures	3,008,851	5,354,947	3,731,503	2,572,842	2,997,851	2,251,443	2,376,837	2,134,213	2,108,785	2,863,364	2,675,127	4,253,416
AFUDC Debt	45,513	49,360	53,637	55,493	56,034	57,884	59,701	62,496	65,300	68,603	72,490	71,680
AFUDC Equity	110,160	119,472	129,823	134,315	135,624	140,103	144,501	151,266	158,052	166,047	175,455	173,494
Closings to Plant	(137,125)	(20,625)	(2,989,076)	(3,177,148)	(1,191,868)	(1,231,678)	(421,158)	(7,904)	(192,578)	(4,319)	(70,854)	(12,926,539)
Electric Intangible CWIP	33,571,078	39,074,233	40,000,120	39,585,621	41,583,263	42,801,015	44,960,896	47,300,967	49,440,527	52,534,221	55,386,439	46,958,490
Electric Steam Production Plant												
CWIP Beginning Balance	5,965,038	8,169,186	9,501,271	8,051,220	7,291,313	6,692,435	8,255,755	10,671,846	12,799,055	13,321,555	8,496,806	6,534,533
CWIP Expenditures	2,473,075	1,977,318	2,413,060	2,327,789	1,445,578	2,133,171	2,606,511	2,637,937	2,663,012	1,155,872	1,343,473	1,199,858
AFUDC Debt	10,812	13,521	13,799	11,884	10,772	11,465	14,489	17,984	20,283	16,830	11,513	9,913
AFUDC Equity	26,169	32,726	33,399	28,764	26,073	27,750	35,068	43,528	49,094	40,736	27,866	23,994
Closings to Plant	(305,909)	(691,480)	(3,910,309)	(3,128,343)	(2,081,301)	(609,067)	(239,977)	(572,241)	(2,209,890)	(6,038,186)	(3,345,125)	(1,406,232)
Electric Steam Production CWIP	8,169,186	9,501,271	8,051,220	7,291,313	6,692,435	8,255,755	10,671,846	12,799,055	13,321,555	8,496,806	6,534,533	6,362,066
Electric Nuclear Production Plant												
CWIP Beginning Balance	54,954,821	68,452,897	72,755,848	77,839,288	82,362,189	78,978,234	88,116,805	74,812,223	80,566,465	87,313,745	98,217,883	100,827,633
CWIP Expenditures	13,233,239	5,820,396	5,158,033	4,465,698	6,587,696	9,716,521	11,524,254	8,874,977	10,280,874	18,474,726	12,444,631	10,201,209
AFUDC Debt	94,614	108,472	115,547	122,852	124,031	128,143	125,223	119,522	128,880	143,867	153,132	148,074
AFUDC Equity	229,003	262,547	279,670	297,351	300,204	310,157	303,090	289,290	311,940	348,216	370,642	358,399
Closings to Plant	(58,779)	(1,888,465)	(469,810)	(363,000)	(10,395,886)	(1,016,250)	(25,257,149)	(3,529,547)	(3,974,414)	(8,062,672)	(10,358,655)	(20,236,270)
Electric Nuclear Production CWIP	68,452,897	72,755,848	77,839,288	82,362,189	78,978,234	88,116,805	74,812,223	80,566,465	87,313,745	98,217,883	100,827,633	91,299,045
Electric Hydro Production Plant												
CWIP Beginning Balance	245,493	248,441	251,406	254,379	257,354	260,247	267,439	274,670	281,916	272,362	275,307	278,332
CWIP Expenditures	1,667	1,667	1,667	1,667	1,667	5,833	5,833	5,833	5,833	5,833	5,833	1,667
AFUDC Debt	379	384	388	393	397	405	416	427	427	420	425	430
AFUDC Equity	918	929	940	951	962	980	1,007	1,034	1,034	1,017	1,028	1,040
Closings to Plant	(15)	(14)	(21)	(35)	(132)	(27)	(25)	(49)	(16,848)	(4,325)	(4,262)	(65)
Electric Hydro Production CWIP	248,441	251,406	254,379	257,354	260,247	267,439	274,670	281,916	272,362	275,307	278,332	281,403
Electric Other Production Plant												
CWIP Beginning Balance	157,000,829	227,440,359	233,052,464	240,617,059	292,992,727	351,630,529	413,044,503	498,826,638	559,992,701	615,307,062	639,474,208	678,531,454
CWIP Expenditures	72,415,805	4,763,113	5,036,780	53,647,576	59,143,513	62,839,003	85,176,862	59,751,921	58,407,219	44,080,158	45,550,472	61,418,567
AFUDC Debt	260,675	319,016	329,751	375,254	460,398	552,512	665,497	778,269	867,934	929,914	977,580	725,088
AFUDC Equity	630,938	772,148	798,130	908,266	1,114,348	1,337,303	1,610,771	1,883,724	2,100,749	2,250,768	2,366,138	1,755,004
Closings to Plant	(2,867,888)	(242,172)	1,399,933	(2,555,428)	(2,080,456)	(3,314,843)	(1,670,996)	(1,247,851)	(6,061,541)	(23,093,693)	(9,836,945)	(457,253,261)
Electric Other Production CWIP	227,440,359	233,052,464	240,617,059	292,992,727	351,630,529	413,044,503	498,826,638	559,992,701	615,307,062	639,474,208	678,531,454	285,176,851
Electric Transmission Plant												
CWIP Beginning Balance	30,899,364	48,030,751	58,281,893	66,359,456	83,423,013	85,307,673	80,054,974	99,459,994	112,069,878	125,768,204	144,851,613	167,824,849
CWIP Expenditures	19,592,977	18,998,914	24,906,032	18,859,842	17,466,803	22,240,021	20,710,835	17,722,884	29,130,980	23,455,928	25,078,160	32,180,422
AFUDC Debt	57,000	78,110	93,856	111,041	126,317	125,561	134,370	161,751	185,505	208,472	240,590	204,957
AFUDC Equity	137,962	189,057	227,170	268,763	305,739	303,907	325,229	391,502	448,996	504,585	582,324	496,077
Closings to Plant	(2,656,552)	(9,014,939)	(17,149,495)	(2,176,089)	(16,014,199)	(27,922,188)	(1,765,413)	(5,666,253)	(16,067,155)	(5,085,576)	(2,927,838)	(111,330,162)
Electric Transmission CWIP	48,030,751	58,281,893	66,359,456	83,423,013	85,307,673	80,054,974	99,459,994	112,069,878	125,768,204	144,851,613	167,824,849	89,376,143
Electric Distribution Plant (1)												
CWIP Beginning Balance	48,707,560	54,553,973	61,260,763	70,668,296	80,562,076	89,608,968	93,304,733	103,218,520	112,082,179	118,610,640	106,279,720	106,852,826
CWIP Expenditures	43,608,063	43,760,331	44,119,703	45,835,671	45,294,019	46,883,638	48,549,687	48,116,620	46,439,696	41,375,231	40,099,499	43,885,470
AFUDC Debt	53,852	70,222	81,805	96,363	110,628	120,603	129,272	141,541	151,916	147,926	139,907	124,460
AFUDC Equity	130,343	169,966	198,000	233,238	267,764	291,907	312,889	342,586	367,699	358,039	338,632	301,244
Closings to Plant	(37,945,844)	(37,293,729)	(34,991,974)	(36,271,493)	(36,625,518)	(43,600,382)	(39,078,061)	(39,737,088)	(40,430,850)	(54,212,116)	(40,004,933)	(65,170,089)
Electric Distribution CWIP	54,553,973	61,260,763	70,668,296	80,562,076	89,608,968	93,304,733	103,218,520	112,082,179	118,610,640	106,279,720	106,852,826	85,993,911
Electric General Plant												
CWIP Beginning Balance	35,524,846	38,441,150	42,520,707	41,078,620	45,072,644	51,847,100	54,111,329	60,635,565	67,044,770	75,811,527	88,987,532	92,731,101
CWIP Expenditures	6,365,623	6,599,671	12,110,116	11,844,624	13,482,213	16,677,905	12,238,028	13,747,049	13,525,233	17,742,442	9,660,744	11,778,809
AFUDC Debt	43,298	47,901	48,742	50,165	56,962	60,421	64,525	74,618	83,787	95,439	104,818	85,095
AFUDC Equity	104,798	115,940	117,976	121,418	137,872	146,244	156,177	180,605	202,800	231,000	253,702	205,965
Closings to Plant	(3,597,416)	(2,683,955)	(13,718,922)	(8,022,183)	(6,902,591)	(14,620,341)	(5,934,495)	(7,593,066)	(5,045,064)	(4,892,875)	(6,275,695)	(46,305,973)
Electric General CWIP	38,441,150	42,520,707	41,078,620	45,072,644	51,847,100	54,111,329	60,635,565	67,044,770	75,811,527	88,987,532	92,731,101	58,494,998
Total Electric Utility	478,907,834	516,698,583	544,868,437	631,546,936	705,908,449	779,956,553	892,860,353	992,137,932	1,085,845,621	1,139,117,290	1,208,967,166	663,942,907

Northern States Power Company
Roll Forward by Functional Class
CWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 4 of 36

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
CWIP Beginning Balance	20,527,593	27,985,652	34,501,290	44,367,575	51,925,704	59,511,740	66,679,354	74,138,787	80,718,529	87,345,258	94,526,307	100,145,899
CWIP Expenditures	7,267,112	6,779,767	11,210,291	7,615,175	7,574,803	7,556,940	7,562,805	7,586,820	7,579,852	7,835,684	7,386,936	7,261,124
AFUDC Debt	36,589	44,957	53,556	62,631	71,600	80,427	89,235	97,707	105,693	114,203	121,842	78,166
AFUDC Equity	88,560	108,815	129,627	151,591	173,301	194,666	215,984	236,491	255,819	276,416	294,906	189,193
Closings to Plant	65,798	(417,901)	(1,527,189)	(271,268)	(233,668)	(664,420)	(408,591)	(1,341,277)	(1,314,635)	(1,045,254)	(2,184,092)	(86,973,646)
Common Intangible CWIP	27,985,652	34,501,290	44,367,575	51,925,704	59,511,740	66,679,354	74,138,787	80,718,529	87,345,258	94,526,307	100,145,899	20,700,736
Common General Plant												
CWIP Beginning Balance	42,873,232	49,711,415	57,961,205	60,797,166	64,813,044	73,181,855	74,029,313	81,770,957	52,639,488	54,665,500	58,451,375	63,182,124
CWIP Expenditures	6,928,954	8,290,889	6,876,217	6,980,959	8,909,437	9,184,138	9,016,480	9,441,681	10,370,013	7,668,044	7,364,123	7,682,949
AFUDC Debt	60,507	67,064	72,864	77,880	84,199	89,302	93,599	73,417	51,812	54,446	55,810	42,530
AFUDC Equity	146,452	162,322	176,359	188,500	203,795	216,147	226,548	177,698	125,406	131,781	135,083	102,939
Closings to Plant	(297,730)	(270,484)	(4,289,479)	(3,231,461)	(828,619)	(8,642,128)	(1,594,984)	(38,824,264)	(8,521,220)	(4,068,396)	(2,824,266)	(38,685,997)
Common General CWIP	49,711,415	57,961,205	60,797,166	64,813,044	73,181,855	74,029,313	81,770,957	52,639,488	54,665,500	58,451,375	63,182,124	32,324,545
Total Common Utility	77,697,067	92,462,495	105,164,741	116,738,747	132,693,595	140,708,668	155,909,744	133,358,017	142,010,757	152,977,682	163,328,023	53,025,281
Nuclear Fuel												
CWIP Beginning Balance	101,869,084	103,576,768	105,897,606	106,524,892	107,292,615	115,252,995	119,592,854	120,456,347	127,041,490	50,524,760	50,912,091	52,210,123
CWIP Expenditures	1,168,370	1,770,949	69,658	206,432	7,376,178	3,723,367	233,342	5,935,439	61,127	122,428	1,560,121	64,594,805
AFUDC Debt	157,676	160,767	163,030	164,101	170,799	180,240	184,233	189,950	136,449	77,851	79,144	130,057
AFUDC Equity	381,638	389,122	394,598	397,190	413,403	436,252	445,918	459,755	330,261	188,430	191,561	314,791
Closings to Plant	-	-	-	-	-	-	-	-	(77,044,566)	(1,378)	(532,795)	-
Nuclear Fuel CWIP	103,576,768	105,897,606	106,524,892	107,292,615	115,252,995	119,592,854	120,456,347	127,041,490	50,524,760	50,912,091	52,210,123	117,249,775
Total Nuclear Fuel	103,576,768	105,897,606	106,524,892	107,292,615	115,252,995	119,592,854	120,456,347	127,041,490	50,524,760	50,912,091	52,210,123	117,249,775
Total Electric, Common, and Nuclear Fuel	**660,181,669**	**715,058,683**	**756,558,070**	**855,578,298**	**953,855,039**	**1,040,258,074**	**1,169,226,444**	**1,252,537,439**	**1,278,381,139**	**1,343,007,063**	**1,424,505,311**	**834,217,964**

Footnotes:
(1) Electric Distribution Plant in the schedule above conta

Electric Distribution Plant - MN located only												
CWIP Beginning Balance	38,486,617	42,141,064	51,316,799	59,670,237	67,939,118	75,143,087	76,921,240	85,541,276	93,166,695	98,744,308	85,909,258	86,439,336
CWIP Expenditures	38,901,967	39,103,811	39,403,531	40,468,221	39,907,291	41,203,171	43,475,788	43,206,443	41,806,743	37,139,995	36,525,773	40,068,561
AFUDC Debt	43,207	58,451	71,152	83,311	94,681	101,595	107,813	118,238	127,002	121,846	113,269	98,682
AFUDC Equity	104,579	141,476	172,216	201,647	229,166	245,901	260,951	286,183	307,395	294,917	274,157	238,851
Closings to Plant	(35,395,306)	(30,128,003)	(31,293,461)	(32,484,299)	(33,027,169)	(39,772,515)	(35,224,516)	(35,985,445)	(36,663,527)	(50,391,809)	(36,383,122)	(60,075,949)
Electric Distribution CWIP (MN Only)	42,141,064	51,316,799	59,670,237	67,939,118	75,143,087	76,921,240	85,541,276	93,166,695	98,744,308	85,909,258	86,439,336	66,769,481

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
CWIP Beginning Balance	46,958,490	41,353,534	46,191,162	39,536,790	42,185,796	39,485,772	40,776,359	42,756,145	44,524,355	46,148,085	38,826,539	40,661,439
CWIP Expenditures	2,604,665	6,029,423	3,370,783	3,057,342	2,094,936	2,083,936	2,116,716	1,894,636	1,999,036	2,648,580	1,994,094	2,523,624
AFUDC Debt	59,381	56,034	55,327	54,980	54,891	53,679	55,680	58,201	60,495	56,149	51,913	46,967
AFUDC Equity	140,903	132,960	131,283	130,460	130,247	127,373	132,120	138,103	143,546	133,235	123,182	111,447
Closings to Plant	(8,409,905)	(1,380,790)	(10,211,765)	(593,776)	(4,980,097)	(974,401)	(324,730)	(322,730)	(579,347)	(10,159,509)	(334,288)	(15,549,979)
Electric Intangible CWIP	41,353,534	46,191,162	39,536,790	42,185,796	39,485,772	40,776,359	42,756,145	44,524,355	46,148,085	38,826,539	40,661,439	27,793,498
Electric Steam Production Plant												
CWIP Beginning Balance	6,362,066	7,611,004	7,563,257	7,245,187	7,536,507	5,137,501	5,882,449	6,903,217	7,821,620	7,951,471	4,449,543	5,106,279
CWIP Expenditures	1,506,138	1,241,146	2,042,206	1,436,682	1,675,193	1,524,416	1,366,176	1,311,870	1,481,280	1,025,618	1,878,952	2,896,404
AFUDC Debt	10,107	10,983	11,010	10,713	9,359	7,990	9,301	10,661	11,579	9,098	6,951	8,783
AFUDC Equity	23,982	26,061	26,126	25,419	22,208	18,960	22,069	25,298	27,475	21,589	16,494	20,841
Closings to Plant	(291,289)	(1,325,937)	(2,397,413)	(1,181,493)	(4,105,767)	(806,419)	(376,777)	(429,426)	(1,390,483)	(4,558,233)	(1,245,662)	(1,104,759)
Electric Steam Production CWIP	7,611,004	7,563,257	7,245,187	7,536,507	5,137,501	5,882,449	6,903,217	7,821,620	7,951,471	4,449,543	5,106,279	6,927,548
Electric Nuclear Production Plant												
CWIP Beginning Balance	91,299,045	102,078,354	111,880,283	104,817,239	109,264,549	85,866,366	92,063,960	84,574,516	90,832,394	101,951,244	107,983,683	107,941,877
CWIP Expenditures	10,386,480	9,342,647	11,054,934	13,571,837	13,729,832	10,022,233	8,842,686	9,112,515	12,241,576	13,214,504	6,742,350	7,804,781
AFUDC Debt	140,636	155,613	158,201	155,750	143,852	129,425	128,623	127,736	140,240	154,022	157,491	134,792
AFUDC Equity	333,709	369,248	375,389	369,574	341,339	307,106	305,204	303,099	332,770	365,472	373,703	319,841
Closings to Plant	(81,516)	(65,578)	(18,651,569)	(9,649,851)	(37,613,206)	(4,261,169)	(16,765,957)	(3,285,472)	(1,595,737)	(7,701,559)	(7,315,349)	(40,178,266)
Electric Nuclear Production CWIP	102,078,354	111,880,283	104,817,239	109,264,549	85,866,366	92,063,960	84,574,516	90,832,394	101,951,244	107,983,683	107,941,877	76,023,024
Electric Hydro Production Plant												
CWIP Beginning Balance	281,403	287,798	294,225	300,683	307,171	313,681	325,246	336,868	348,545	360,281	382,085	404,005
CWIP Expenditures	5,000	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	20,000	20,000	35,000
AFUDC Debt	414	424	433	442	452	465	482	499	516	540	572	615
AFUDC Equity	983	1,005	1,027	1,050	1,072	1,103	1,143	1,184	1,224	1,282	1,357	1,459
Closings to Plant	(2)	(2)	(2)	(4)	(14)	(3)	(3)	(5)	(5)	(17)	(10)	(7)
Electric Hydro Production CWIP	287,798	294,225	300,683	307,171	313,681	325,246	336,868	348,545	360,281	382,085	404,005	441,072
Electric Other Production Plant												
CWIP Beginning Balance	285,176,851	305,967,577	323,778,359	341,836,423	362,746,374	415,176,147	458,547,483	507,627,011	547,108,095	584,515,173	343,233,128	247,398,107
CWIP Expenditures	20,326,799	17,593,489	27,429,567	36,474,959	55,459,771	42,492,508	47,160,295	37,684,926	35,561,819	36,131,808	33,456,734	34,193,589
AFUDC Debt	397,561	425,670	452,195	480,849	533,633	603,238	670,485	734,953	790,941	648,750	398,232	337,427
AFUDC Equity	943,357	1,010,054	1,072,996	1,140,985	1,266,234	1,431,399	1,590,965	1,743,938	1,876,792	1,539,392	944,948	800,666
Closings to Plant	(876,991)	(1,218,432)	(10,896,695)	(17,186,842)	(4,829,865)	(1,155,809)	(342,217)	(682,733)	(822,474)	(279,601,996)	(130,634,934)	(21,913,359)
Electric Other Production CWIP	305,967,577	323,778,359	341,836,423	362,746,374	415,176,147	458,547,483	507,627,011	547,108,095	584,515,173	343,233,128	247,398,107	260,816,430
Electric Transmission Plant												
CWIP Beginning Balance	89,376,143	102,020,229	103,628,648	102,251,154	112,352,092	125,089,373	109,091,268	120,953,095	134,121,356	139,889,651	157,767,266	175,477,964
CWIP Expenditures	18,828,141	10,696,623	37,222,541	12,180,686	19,296,947	35,428,717	17,817,272	14,105,414	38,890,392	19,713,407	19,602,922	37,883,669
AFUDC Debt	139,691	150,388	154,214	156,679	173,272	176,530	168,213	186,178	205,345	217,001	243,004	223,222
AFUDC Equity	331,467	356,848	365,928	371,778	411,151	418,881	399,146	441,775	487,254	514,912	576,615	529,674
Closings to Plant	(6,655,213)	(9,595,439)	(39,120,177)	(2,608,205)	(7,144,090)	(52,022,233)	(6,522,803)	(1,565,106)	(33,814,697)	(2,567,704)	(2,711,843)	(94,311,244)
Electric Transmission CWIP	102,020,229	103,628,648	102,251,154	112,352,092	125,089,373	109,091,268	120,953,095	134,121,356	139,889,651	157,767,266	175,477,964	119,803,284
Electric Distribution Plant (1)												
CWIP Beginning Balance	85,993,911	89,461,881	93,553,362	98,644,322	97,412,988	104,472,347	89,936,703	97,801,411	97,375,063	102,990,893	79,388,628	79,106,212
CWIP Expenditures	46,123,362	45,695,989	46,270,594	47,545,710	47,787,003	49,125,954	50,232,137	49,803,130	48,775,236	44,901,714	37,983,239	48,890,111
AFUDC Debt	104,169	109,251	115,542	118,167	121,975	117,036	110,193	113,611	115,855	103,567	86,469	89,040
AFUDC Equity	247,179	259,238	274,164	280,393	289,429	277,709	261,473	269,583	274,907	245,750	205,179	211,280
Closings to Plant	(43,006,741)	(41,972,997)	(41,569,340)	(49,175,605)	(41,139,047)	(64,056,343)	(42,739,095)	(50,612,673)	(43,550,167)	(68,853,296)	(38,557,303)	(48,893,565)
Electric Distribution CWIP	89,461,881	93,553,362	98,644,322	97,412,988	104,472,347	89,936,703	97,801,411	97,375,063	102,990,893	79,388,628	79,106,212	79,403,079
Electric General Plant												
CWIP Beginning Balance	58,494,998	63,684,482	68,533,680	69,466,941	50,409,899	59,400,463	66,351,088	77,451,943	91,409,578	95,388,266	104,798,168	114,274,761
CWIP Expenditures	7,499,593	7,024,551	13,359,731	12,821,135	14,717,596	18,839,692	17,454,173	17,192,002	15,337,697	13,503,392	13,670,609	13,599,302
AFUDC Debt	60,106	65,415	68,066	52,914	42,859	52,002	61,384	76,631	87,631	93,864	105,257	92,112
AFUDC Equity	142,624	155,221	161,510	125,557	101,698	123,393	145,655	181,834	207,937	222,727	249,759	218,569
Closings to Plant	(2,512,839)	(2,395,990)	(12,656,045)	(32,056,649)	(5,871,589)	(12,064,461)	(6,560,356)	(3,492,831)	(11,654,577)	(4,410,081)	(4,549,031)	(50,970,358)
Electric General CWIP	63,684,482	68,533,680	69,466,941	50,409,899	59,400,463	66,351,088	77,451,943	91,409,578	95,388,266	104,798,168	114,274,761	77,214,387
Total Electric Utility	712,464,859	755,422,977	764,098,738	782,215,375	834,941,650	862,974,557	938,404,206	1,013,541,006	1,079,195,063	836,829,039	770,370,643	648,422,321

Northern States Power Company
Roll Forward by Functional Class
CWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 6 of 36

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
CWIP Beginning Balance	20,700,736	23,920,583	13,409,453	18,505,269	23,541,270	28,542,337	33,525,920	38,504,268	43,485,991	47,827,924	52,781,333	57,751,231
CWIP Expenditures	3,851,793	3,851,793	7,446,372	5,864,964	5,864,964	5,864,964	5,864,964	5,864,964	5,864,964	5,827,834	5,827,834	7,926,834
AFUDC Debt	28,046	23,447	20,014	26,758	33,536	40,346	47,190	54,068	60,526	66,943	73,848	50,799
AFUDC Equity	66,548	55,636	47,491	63,493	79,575	95,736	111,976	128,296	143,620	158,847	175,231	120,539
Closings to Plant	(726,541)	(14,442,007)	(2,418,061)	(919,214)	(977,007)	(1,017,463)	(1,045,782)	(1,065,605)	(1,727,176)	(1,100,214)	(1,107,014)	(48,635,849)
Common Intangible CWIP	23,920,583	13,409,453	18,505,269	23,541,270	28,542,337	33,525,920	38,504,268	43,485,991	47,827,924	52,781,333	57,751,231	17,213,553
Common General Plant												
CWIP Beginning Balance	32,324,545	33,816,628	35,470,013	33,734,858	36,829,314	42,638,536	43,596,879	49,659,793	56,328,140	33,996,806	40,094,892	45,363,641
CWIP Expenditures	2,632,788	2,729,766	4,158,471	4,216,727	6,780,048	7,286,751	7,104,157	7,620,244	7,265,026	7,128,733	7,279,003	7,189,826
AFUDC Debt	25,600	26,018	26,619	27,490	30,189	34,960	40,121	45,532	40,832	35,925	40,305	26,218
AFUDC Equity	60,746	61,738	63,163	65,230	71,634	82,955	95,201	108,042	96,889	85,244	95,639	62,212
Closings to Plant	(1,227,051)	(1,164,137)	(5,983,408)	(1,214,991)	(1,072,648)	(6,446,323)	(1,176,564)	(1,105,472)	(29,734,081)	(1,151,815)	(2,146,198)	(41,291,513)
Common General CWIP	33,816,628	35,470,013	33,734,858	36,829,314	42,638,536	43,596,879	49,659,793	56,328,140	33,996,806	40,094,892	45,363,641	11,350,384
Total Common Utility	57,737,211	48,879,466	52,240,127	60,370,584	71,180,873	77,122,799	88,164,061	99,814,130	81,824,729	92,876,224	103,114,872	28,563,937
Nuclear Fuel												
CWIP Beginning Balance	117,249,775	118,388,070	180,757,671	112,288,536	112,873,086	119,356,692	123,788,354	124,602,576	54,895,486	55,202,140	55,510,704	55,820,909
CWIP Expenditures	559,931	61,635,359	14,965,260	342,837	6,684,192	3,848,091	204,556	2,097,017	38,161	586,055	36,946	13,378,507
AFUDC Debt	171,476	217,691	239,820	163,852	168,996	176,939	180,756	153,236	80,119	80,567	81,017	91,202
AFUDC Equity	406,888	516,550	569,059	388,798	401,003	419,851	428,909	363,607	190,111	191,174	192,242	216,410
Closings to Plant	-	-	(84,243,274)	(310,937)	(770,585)	(13,219)	-	(72,320,950)	(1,738)	(549,231)	-	-
Nuclear Fuel CWIP	118,388,070	180,757,671	112,288,536	112,873,086	119,356,692	123,788,354	124,602,576	54,895,486	55,202,140	55,510,704	55,820,909	69,507,028
Total Nuclear Fuel	118,388,070	180,757,671	112,288,536	112,873,086	119,356,692	123,788,354	124,602,576	54,895,486	55,202,140	55,510,704	55,820,909	69,507,028
Total Electric, Common, and Nuclear Fuel	**888,590,139**	**985,060,113**	**928,627,401**	**955,459,046**	**1,025,479,215**	**1,063,885,710**	**1,151,170,843**	**1,168,250,623**	**1,216,221,931**	**985,215,967**	**929,306,425**	**746,493,287**

Footnotes:
(1) Electric Distribution Plant in the schedule above cont

Electric Distribution Plant - MN located only												
CWIP Beginning Balance	66,769,481	69,199,033	72,225,435	76,182,815	73,366,797	78,711,988	75,928,624	82,618,173	81,084,565	85,844,557	75,230,174	75,039,795
CWIP Expenditures	41,351,587	41,082,240	41,606,910	42,286,677	42,551,960	43,627,305	45,176,826	44,907,479	44,110,589	40,760,417	35,291,769	40,739,753
AFUDC Debt	79,874	83,349	87,991	88,607	89,987	91,953	93,267	95,175	96,093	92,396	84,917	85,566
AFUDC Equity	189,529	197,775	208,789	210,252	213,526	218,190	221,310	225,838	228,015	219,243	201,496	203,036
Closings to Plant	(39,191,437)	(38,336,963)	(37,946,310)	(45,401,553)	(37,510,283)	(46,720,812)	(38,801,854)	(46,762,100)	(39,674,706)	(51,686,439)	(35,768,561)	(40,671,387)
Electric Distribution CWIP (MN Only)	69,199,033	72,225,435	76,182,815	73,366,797	78,711,988	75,928,624	82,618,173	81,084,565	85,844,557	75,230,174	75,039,795	75,396,763

Northern States Power Company
Roll Forward by Functional Class
CWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 7 of 36

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
CWIP Beginning Balance	27,793,498	28,675,776	31,280,176	30,597,418	31,866,978	32,828,607	33,795,003	34,801,254	35,960,438	37,093,253	38,176,061	39,287,638
CWIP Expenditures	6,588,775	2,460,376	1,451,466	1,114,829	801,376	1,266,376	836,376	984,103	1,417,376	897,376	921,376	1,799,377
AFUDC Debt	41,999	43,236	44,837	46,450	48,108	49,713	50,996	52,559	54,342	55,667	57,098	54,283
AFUDC Equity	97,903	100,788	104,519	108,280	112,145	115,887	118,878	122,522	126,677	129,765	133,102	126,541
Closings to Plant	(5,846,399)	-	(2,283,580)	-	-	(465,580)	-	-	(465,580)	-	-	(7,140,755)
Electric Intangible CWIP	28,675,776	31,280,176	30,597,418	31,866,978	32,828,607	33,795,003	34,801,254	35,960,438	37,093,253	38,176,061	39,287,638	34,127,085
Electric Steam Production Plant												
CWIP Beginning Balance	6,927,548	7,918,064	6,396,172	7,321,619	7,694,872	7,362,763	4,380,354	5,079,706	5,531,833	6,159,870	5,742,460	5,391,912
CWIP Expenditures	1,222,758	903,114	2,115,407	1,105,674	1,319,221	681,638	1,152,819	735,572	1,006,717	1,413,709	780,897	1,563,594
AFUDC Debt	11,055	10,690	10,422	11,207	11,314	8,744	7,054	7,905	8,710	8,941	8,330	7,150
AFUDC Equity	25,772	24,920	24,296	26,124	26,375	20,383	16,445	18,427	20,304	20,842	19,419	16,668
Closings to Plant	(269,069)	(2,460,616)	(1,224,678)	(769,751)	(1,689,019)	(3,693,173)	(476,966)	(309,777)	(407,694)	(1,860,902)	(1,159,194)	(3,269,490)
Electric Steam Production CWIP	7,918,064	6,396,172	7,321,619	7,694,872	7,362,763	4,380,354	5,079,706	5,531,833	6,159,870	5,742,460	5,391,912	3,709,834
Electric Nuclear Production Plant												
CWIP Beginning Balance	76,023,024	78,750,412	81,443,450	88,437,162	92,813,665	97,758,822	102,720,939	114,150,550	120,518,804	131,586,390	137,565,846	137,417,661
CWIP Expenditures	2,352,257	2,300,601	7,536,698	3,949,523	4,489,010	4,687,625	11,073,938	6,242,254	15,446,785	12,915,551	7,186,071	6,907,188
AFUDC Debt	115,563	119,612	126,942	135,345	142,309	149,712	161,958	175,258	188,694	201,992	205,820	187,095
AFUDC Equity	269,389	278,829	295,915	315,503	331,738	348,995	377,542	408,546	439,867	470,864	479,788	436,138
Closings to Plant	(9,820)	(6,004)	(965,843)	(23,868)	(17,900)	(224,214)	(183,827)	(457,805)	(5,007,760)	(7,608,950)	(8,019,864)	(33,290,527)
Electric Nuclear Production CWIP	78,750,412	81,443,450	88,437,162	92,813,665	97,758,822	102,720,939	114,150,550	120,518,804	131,586,390	137,565,846	137,417,661	111,657,555
Electric Hydro Production Plant												
CWIP Beginning Balance	441,072	481,283	521,695	562,309	603,125	644,144	685,368	726,798	768,435	810,280	852,332	894,594
CWIP Expenditures	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,924
AFUDC Debt	689	749	810	871	932	993	1,055	1,117	1,180	1,242	1,305	1,369
AFUDC Equity	1,606	1,747	1,888	2,030	2,172	2,316	2,460	2,604	2,750	2,896	3,043	3,190
Closings to Plant	(0)	(0)	(0)	(0)	(2)	(0)	(0)	(1)	(1)	(2)	(1)	(1)
Electric Hydro Production CWIP	481,283	521,695	562,309	603,125	644,144	685,368	726,798	768,435	810,280	852,332	894,594	937,076
Electric Other Production Plant												
CWIP Beginning Balance	260,816,430	290,364,825	320,843,106	367,875,961	416,628,861	463,338,862	507,471,640	539,417,192	591,866,825	631,414,836	411,466,562	420,622,569
CWIP Expenditures	29,042,956	29,690,889	49,047,705	47,608,904	45,968,721	42,166,582	38,633,899	51,295,222	41,012,118	74,162,654	29,877,564	30,719,435
AFUDC Debt	378,318	423,167	481,298	552,665	624,048	691,851	749,076	811,781	880,746	751,462	588,647	611,654
AFUDC Equity	881,900	986,447	1,121,958	1,288,322	1,454,723	1,612,780	1,746,178	1,892,349	2,053,114	1,751,740	1,372,200	1,425,831
Closings to Plant	(754,778)	(622,221)	(3,618,106)	(696,992)	(1,337,491)	(338,436)	(9,183,601)	(1,549,720)	(4,397,966)	(296,614,130)	(22,682,405)	(10,698,801)
Electric Other Production CWIP	290,364,825	320,843,106	367,875,961	416,628,861	463,338,862	507,471,640	539,417,192	591,866,825	631,414,836	411,466,562	420,622,569	442,680,688
Electric Transmission Plant												
CWIP Beginning Balance	119,803,284	135,468,618	146,648,932	155,774,914	173,419,612	188,109,545	180,489,043	203,269,369	216,899,704	223,760,079	250,473,535	269,279,114
CWIP Expenditures	21,365,890	11,754,084	33,875,374	17,845,389	14,810,150	35,105,152	23,438,719	14,104,609	42,860,344	26,706,181	18,820,695	42,389,369
AFUDC Debt	192,937	211,159	229,680	246,339	270,497	279,231	287,293	314,497	334,097	354,715	388,820	378,374
AFUDC Equity	449,756	492,233	535,409	574,243	630,559	650,918	669,711	733,126	778,815	826,879	906,381	882,031
Closings to Plant	(6,343,248)	(1,277,162)	(25,514,482)	(1,021,272)	(1,021,272)	(43,655,804)	(1,615,396)	(1,521,896)	(37,112,881)	(1,174,318)	(1,310,318)	(84,082,476)
Electric Transmission CWIP	135,468,618	146,648,932	155,774,914	173,419,612	188,109,545	180,489,043	203,269,369	216,899,704	223,760,079	250,473,535	269,279,114	228,846,412
Electric Distribution Plant (1)												
CWIP Beginning Balance	79,403,079	83,267,496	87,288,945	91,566,163	96,651,841	102,549,084	98,433,067	105,939,528	112,579,740	118,007,452	75,608,905	75,377,388
CWIP Expenditures	44,327,789	44,073,908	44,258,107	45,313,522	45,862,409	46,732,161	49,234,087	48,963,812	43,721,569	39,337,061	35,813,814	47,851,704
AFUDC Debt	91,322	96,798	102,596	109,245	117,158	118,911	119,374	127,569	134,986	108,356	77,076	79,030
AFUDC Equity	212,881	225,648	239,162	254,661	273,107	277,195	278,273	297,378	314,668	252,591	179,672	184,228
Closings to Plant	(40,767,576)	(40,374,905)	(40,322,647)	(40,591,750)	(40,355,430)	(51,244,285)	(42,125,272)	(42,748,548)	(38,743,510)	(82,096,556)	(36,302,079)	(49,232,215)
Electric Distribution CWIP	83,267,496	87,288,945	91,566,163	96,651,841	102,549,084	98,433,067	105,939,528	112,579,740	118,007,452	75,608,905	75,377,388	74,260,137
Electric General Plant												
CWIP Beginning Balance	77,214,387	88,688,768	99,612,874	99,602,337	105,218,785	111,573,665	112,518,931	120,209,670	123,564,861	120,303,039	125,443,320	103,452,181
CWIP Expenditures	13,528,616	13,249,958	9,554,029	11,280,056	12,719,648	12,250,837	13,097,849	12,140,521	9,784,449	9,326,781	7,014,987	11,442,791
AFUDC Debt	77,840	92,240	98,875	100,224	107,319	111,796	115,469	123,940	126,565	126,417	132,305	119,613
AFUDC Equity	181,453	215,022	230,489	233,634	250,172	260,609	269,170	288,917	295,036	294,692	308,416	278,832
Closings to Plant	(2,313,528)	(2,633,115)	(9,893,930)	(5,997,467)	(6,722,259)	(11,677,976)	(5,791,749)	(9,198,186)	(13,467,872)	(4,607,609)	(29,446,846)	(38,022,585)
Electric General CWIP	88,688,768	99,612,874	99,602,337	105,218,785	111,573,665	112,518,931	120,209,670	123,564,861	120,303,039	125,443,320	103,452,181	77,270,832
Total Electric Utility	713,615,242	774,035,350	841,737,883	924,897,738	1,004,165,492	1,040,494,345	1,123,594,067	1,207,690,640	1,269,135,198	1,045,329,022	1,051,723,057	973,489,618

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
CWIP Beginning Balance	17,213,553	19,185,381	21,015,460	23,393,182	25,708,276	27,343,354	29,462,585	31,566,565	33,662,841	35,756,709	37,851,893	39,951,013
CWIP Expenditures	3,149,551	3,149,363	3,792,508	3,791,773	3,791,398	3,665,123	3,654,628	3,654,628	3,654,628	3,654,628	3,654,628	3,654,628
AFUDC Debt	22,941	25,027	27,604	30,677	33,335	35,815	38,740	41,678	44,632	47,600	50,583	37,575
AFUDC Equity	53,477	58,339	64,349	71,511	77,708	83,490	90,306	97,157	104,042	110,961	117,915	87,592
Closings to Plant	(1,254,141)	(1,402,651)	(1,506,740)	(1,578,866)	(2,267,363)	(1,665,197)	(1,679,694)	(1,697,188)	(1,709,434)	(1,718,006)	(1,724,007)	(24,930,647)
Common Intangible CWIP	19,185,381	21,015,460	23,393,182	25,708,276	27,343,354	29,462,585	31,566,565	33,662,841	35,756,709	37,851,893	39,951,013	18,800,161
Common General Plant												
CWIP Beginning Balance	11,350,384	13,253,146	15,228,917	12,798,314	15,810,763	19,203,045	17,463,409	20,761,519	24,264,401	22,147,125	25,500,720	28,962,934
CWIP Expenditures	2,780,120	2,822,124	4,068,621	3,885,454	4,359,307	4,769,285	4,275,923	4,487,609	4,371,173	4,534,367	4,384,916	4,467,116
AFUDC Debt	8,349	8,456	8,633	8,958	9,648	10,655	11,589	12,395	13,170	13,949	14,684	13,485
AFUDC Equity	19,462	19,712	20,125	20,883	22,491	24,837	27,015	28,893	30,701	32,516	34,229	31,436
Closings to Plant	(905,169)	(874,522)	(6,527,982)	(902,846)	(999,165)	(6,544,413)	(1,016,417)	(1,026,015)	(6,532,321)	(1,227,237)	(971,615)	(18,711,959)
Common General CWIP	13,253,146	15,228,917	12,798,314	15,810,763	19,203,045	17,463,409	20,761,519	24,264,401	22,147,125	25,500,720	28,962,934	14,763,013
Total Common Utility	32,438,527	36,244,376	36,191,495	41,519,039	46,546,399	46,925,994	52,328,084	57,927,242	57,903,835	63,352,613	68,913,947	33,563,174
Nuclear Fuel												
CWIP Beginning Balance	69,507,028	70,222,405	74,592,160	78,110,781	78,614,788	86,407,846	93,071,627	97,452,579	100,833,742	32,788,428	32,974,634	33,168,507
CWIP Expenditures	367,619	4,009,342	3,138,576	113,949	7,382,352	6,217,094	3,906,777	2,887,670	1,818,883	24,011	598,566	52,536,805
AFUDC Debt	104,397	108,196	114,090	117,095	123,294	134,096	142,347	148,147	122,115	49,134	49,418	89,036
AFUDC Equity	243,360	252,217	265,956	272,962	287,412	312,591	331,827	345,346	284,664	114,537	115,199	207,554
Closings to Plant	-	-	-	-	-	-	-	-	(70,270,977)	(1,475)	(569,310)	-
Nuclear Fuel CWIP	70,222,405	74,592,160	78,110,781	78,614,788	86,407,846	93,071,627	97,452,579	100,833,742	32,788,428	32,974,634	33,168,507	86,001,902
Total Nuclear Fuel	70,222,405	74,592,160	78,110,781	78,614,788	86,407,846	93,071,627	97,452,579	100,833,742	32,788,428	32,974,634	33,168,507	86,001,902
Total Electric, Common, and Nuclear Fuel	**816,276,174**	**884,871,886**	**956,040,160**	**1,045,031,565**	**1,137,119,737**	**1,180,491,966**	**1,273,374,730**	**1,366,451,624**	**1,359,827,460**	**1,141,656,269**	**1,153,805,511**	**1,093,054,694**

Footnotes:
(1) Electric Distribution Plant in the schedule above conta

Electric Distribution Plant - MN located only												
CWIP Beginning Balance	75,396,763	78,870,334	82,454,771	86,245,198	90,617,846	95,750,393	94,422,769	101,694,037	108,172,156	113,511,031	71,383,235	71,231,220
CWIP Expenditures	41,694,465	41,436,399	41,597,720	42,445,175	42,934,910	43,745,509	46,677,331	46,407,986	41,215,131	37,153,854	33,646,416	45,423,483
AFUDC Debt	89,647	94,452	99,535	105,277	112,084	115,093	117,836	125,919	133,283	106,793	75,692	77,661
AFUDC Equity	208,977	220,177	232,026	245,413	261,280	268,295	274,689	293,530	310,697	248,946	176,446	181,037
Closings to Plant	(38,519,518)	(38,166,590)	(38,138,854)	(38,423,217)	(38,175,727)	(45,456,520)	(39,798,588)	(40,349,315)	(36,320,236)	(79,637,389)	(34,050,570)	(46,920,732)
Electric Distribution CWIP (MN Only)	78,870,334	82,454,771	86,245,198	90,617,846	95,750,393	94,422,769	101,694,037	108,172,156	113,511,031	71,383,235	71,231,220	69,992,669

Northern States Power Company
Roll Forward by Functional Class
Plant In-Service

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 9 of 36

	2021											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Gross Plant Beginning Balance	400,884,072	401,199,442	401,268,458	401,291,067	405,317,755	405,563,522	410,210,787	413,289,583	416,957,482	424,005,304	424,125,796	424,229,426
Plant Additions	315,370	69,016	22,609	4,026,688	245,768	4,647,265	3,078,796	3,667,899	7,047,822	120,492	103,630	22,451,852
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant	401,199,442	401,268,458	401,291,067	405,317,755	405,563,522	410,210,787	413,289,583	416,957,482	424,005,304	424,125,796	424,229,426	446,681,279
Electric Steam Production Plant												
Gross Plant Beginning Balance	2,347,387,469	2,347,530,312	2,343,638,909	2,344,926,052	2,349,012,250	2,353,301,445	2,351,727,121	2,352,966,469	2,353,554,277	2,366,900,806	2,370,628,204	2,375,709,737
Plant Additions	142,843	414,726	1,287,142	4,086,199	4,324,946	394,650	1,239,348	587,809	13,346,528	3,727,398	5,081,533	1,828,445
Retirements	-	(4,306,129)	-	-	(35,751)	(1,968,974)	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant	2,347,530,312	2,343,638,909	2,344,926,052	2,349,012,250	2,353,301,445	2,351,727,121	2,352,966,469	2,353,554,277	2,366,900,806	2,370,628,204	2,375,709,737	2,377,538,182
Electric Nuclear Production Plant												
Gross Plant Beginning Balance	3,942,163,350	3,943,024,342	3,941,770,089	3,942,300,455	3,952,406,308	3,976,979,902	3,977,926,964	3,983,535,772	3,986,669,578	4,003,792,713	4,013,403,672	4,020,324,364
Plant Additions	860,992	216,926	530,366	10,217,259	24,573,594	947,062	5,608,808	3,133,807	17,123,134	9,610,960	6,920,692	10,952,213
Retirements	-	(1,471,179)	-	(111,406)	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant	3,943,024,342	3,941,770,089	3,942,300,455	3,952,406,308	3,976,979,902	3,977,926,964	3,983,535,772	3,986,669,578	4,003,792,713	4,013,403,672	4,020,324,364	4,031,276,577
Electric Hydro Production Plant												
Gross Plant Beginning Balance	27,882,287	27,889,166	27,897,104	27,896,669	27,896,669	27,896,669	27,896,669	27,941,018	27,941,464	27,941,868	27,943,329	28,007,134
Plant Additions	6,879	7,937	(435)	-	-	-	44,349	447	404	1,461	63,805	597
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant	27,889,166	27,897,104	27,896,669	27,896,669	27,896,669	27,896,669	27,941,018	27,941,464	27,941,868	27,943,329	28,007,134	28,007,730
Electric Other Production Plant												
Gross Plant Beginning Balance	4,128,924,232	4,457,223,877	4,460,421,027	4,685,568,790	4,689,858,554	5,011,517,824	5,027,582,752	5,031,297,325	5,043,150,599	5,048,593,000	5,060,464,893	5,064,061,588
Plant Additions	328,299,645	7,934,002	225,147,762	4,330,028	321,700,949	18,006,779	3,714,573	11,853,273	5,442,402	11,871,892	3,596,695	401,046,107
Retirements	-	(4,736,852)	-	(40,264)	(41,679)	(1,941,851)	-	-	-	-	-	-
Transfers & Adjustments	0	-	(0)	-	-	-	-	-	-	-	-	-
Electric Other Production Plant	4,457,223,877	4,460,421,027	4,685,568,790	4,689,858,554	5,011,517,824	5,027,582,752	5,031,297,325	5,043,150,599	5,048,593,000	5,060,464,893	5,064,061,588	5,465,107,695
Electric Transmission Plant												
Gross Plant Beginning Balance	3,919,326,875	3,943,887,388	3,944,269,824	3,959,875,555	3,960,589,894	3,993,228,342	4,000,606,277	4,015,257,866	4,019,132,144	4,037,578,107	4,049,100,858	4,053,921,836
Plant Additions	24,560,513	1,722,895	15,745,396	4,108,730	32,638,448	9,930,535	15,615,530	4,838,220	19,409,904	12,486,694	5,784,919	168,932,205
Retirements	-	(1,340,459)	(139,665)	(3,394,391)	-	(2,552,600)	(963,942)	(963,942)	(963,942)	(963,942)	(963,942)	(963,942)
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant	3,943,887,388	3,944,269,824	3,959,875,555	3,960,589,894	3,993,228,342	4,000,606,277	4,015,257,866	4,019,132,144	4,037,578,107	4,049,100,858	4,053,921,836	4,221,890,099
Electric Distribution Plant (1)												
Gross Plant Beginning Balance	4,541,882,928	4,559,018,709	4,572,171,791	4,583,846,668	4,609,687,201	4,629,368,127	4,621,138,325	4,640,834,423	4,662,082,054	4,685,008,632	4,707,999,337	4,728,249,439
Plant Additions	17,232,733	14,991,975	12,255,229	27,017,238	20,597,815	15,237,687	21,789,250	23,427,685	25,106,632	25,170,759	22,430,156	82,845,565
Retirements	(96,952)	(1,838,894)	(580,352)	(1,176,705)	(916,889)	(23,467,489)	(2,093,151)	(2,180,054)	(2,180,054)	(2,180,054)	(2,180,054)	(2,180,054)
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant	4,559,018,709	4,572,171,791	4,583,846,668	4,609,687,201	4,629,368,127	4,621,138,325	4,640,834,423	4,662,082,054	4,685,008,632	4,707,999,337	4,728,249,439	4,808,914,949
Electric General Plant												
Gross Plant Beginning Balance	662,185,961	665,273,529	666,533,586	670,026,241	716,750,707	720,628,247	718,412,903	728,687,097	731,960,907	737,394,405	743,825,643	753,750,978
Plant Additions	3,087,568	1,281,578	7,613,195	46,724,466	3,877,539	8,349,869	10,274,195	3,273,810	5,433,498	6,431,238	9,925,335	21,654,051
Retirements	-	(21,520)	(4,120,540)	-	-	(10,565,213)	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant	665,273,529	666,533,586	670,026,241	716,750,707	720,628,247	718,412,903	728,687,097	731,960,907	737,394,405	743,825,643	753,750,978	775,405,029
Total Electric Utility	20,345,046,765	20,357,970,789	20,615,731,496	20,711,519,338	21,118,484,078	21,135,501,797	21,193,809,553	21,241,448,506	21,331,214,835	21,397,491,733	21,448,254,500	22,154,821,540

	2021											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
Gross Plant Beginning Balance	513,593,465	515,486,421	522,215,238	524,095,314	524,780,067	526,430,196	526,697,782	533,369,913	534,052,750	541,158,587	544,935,472	553,262,449
Plant Additions	1,892,956	6,728,817	1,880,076	684,753	1,650,129	267,586	6,672,131	682,837	7,105,837	3,776,885	8,326,977	82,287,536
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common Intangible Plant	515,486,421	522,215,238	524,095,314	524,780,067	526,430,196	526,697,782	533,369,913	534,052,750	541,158,587	544,935,472	553,262,449	635,549,985
Common General Plant												
Gross Plant Beginning Balance	427,142,765	428,437,109	428,936,424	430,494,932	430,710,926	430,857,664	419,355,719	425,848,575	428,778,348	439,525,400	441,042,685	447,973,335
Plant Additions	1,294,344	530,501	3,213,324	215,994	146,739	2,225,293	6,492,856	2,929,773	10,747,052	1,517,286	6,930,650	31,805,678
Retirements	-	(31,186)	(1,654,817)	-	-	(13,727,239)	-	-	-	-	-	-
Transfers & Adjustments	(0)	-	-	-	-	-	-	-	-	-	-	-
Common General Plant	428,437,109	428,936,424	430,494,932	430,710,926	430,857,664	419,355,719	425,848,575	428,778,348	439,525,400	441,042,685	447,973,335	479,779,013
Total Common Utility	943,923,530	951,151,662	954,590,246	955,490,992	957,287,860	946,053,501	959,218,488	962,831,098	980,683,987	985,978,157	1,001,235,784	1,115,328,998
Nuclear Fuel												
Gross Plant Beginning Balance	2,833,871,244	2,833,871,254	2,833,871,254	2,907,813,653	2,907,844,053	2,907,852,430	2,907,858,217	2,907,858,217	2,907,858,217	2,980,663,795	2,981,177,798	2,981,177,798
Plant Additions	10	-	73,942,400	30,400	8,377	5,787	-	-	72,805,578	514,003	-	-
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	2,833,871,254	2,833,871,254	2,907,813,653	2,907,844,053	2,907,852,430	2,907,858,217	2,907,858,217	2,907,858,217	2,980,663,795	2,981,177,798	2,981,177,798	2,981,177,798
Total Nuclear Fuel	2,833,871,254	2,833,871,254	2,907,813,653	2,907,844,053	2,907,852,430	2,907,858,217	2,907,858,217	2,907,858,217	2,980,663,795	2,981,177,798	2,981,177,798	2,981,177,798
Total Electric Utility, Common Utility, and Nuclear Fuel	24,122,841,549	24,142,993,704	24,478,135,395	24,574,854,383	24,983,624,369	24,989,413,515	25,060,886,259	25,112,137,821	25,292,562,617	25,364,647,688	25,430,668,082	26,251,328,337

Footnotes:

(1) Electric Distribution Plant in the schedule above contains NSPM total company all jurisdictions. Below is the Electric Distribution State of MN only

	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
Gross Plant Beginning Balance	3,982,962,718	3,996,224,536	4,007,664,857	4,018,056,731	4,042,048,153	4,060,590,370	4,051,491,135	4,067,088,491	4,085,521,853	4,105,380,263	4,124,880,714	4,142,603,227
Plant Additions	13,320,116	13,127,708	10,928,102	25,137,622	19,333,759	12,713,320	17,279,743	20,202,652	21,627,701	21,269,741	19,491,804	79,104,759
Retirements	(58,297)	(1,687,387)	(536,227)	(1,146,200)	(791,542)	(21,812,555)	(1,682,387)	(1,769,290)	(1,769,290)	(1,769,290)	(1,769,290)	(1,769,290)
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant - MN	3,996,224,536	4,007,664,857	4,018,056,731	4,042,048,153	4,060,590,370	4,051,491,135	4,067,088,491	4,085,521,853	4,105,380,263	4,124,880,714	4,142,603,227	4,219,938,696

Northern States Power Company
Roll Forward by Functional Class
Plant In-Service

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 11 of 36

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Gross Plant Beginning Balance	446,681,279	446,818,403	446,839,028	449,828,103	453,005,251	454,197,119	455,428,798	455,849,955	455,857,859	456,050,437	456,054,757	456,125,611
Plant Additions	137,125	20,625	2,989,076	3,177,148	1,191,868	1,231,678	421,158	7,904	192,578	4,319	70,854	12,926,539
Retirements	137,125	-	-	-	-	-	-	-	-	-	-	12,926,539
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant	446,818,403	446,839,028	449,828,103	453,005,251	454,197,119	455,428,798	455,849,955	455,857,859	456,050,437	456,054,757	456,125,611	469,052,150
Electric Steam Production Plant												
Gross Plant Beginning Balance	2,377,538,182	2,377,844,091	2,378,535,570	2,382,445,880	2,385,574,223	2,387,655,523	2,388,264,590	2,388,504,567	2,389,076,808	2,391,286,697	2,397,324,884	2,400,670,009
Plant Additions	-	691,480	3,910,310	3,128,343	2,081,301	609,067	239,977	572,241	2,209,890	6,038,187	3,345,125	(227,911,389)
Retirements	305,909	-	-	-	-	-	-	-	-	-	-	1,406,232
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant	2,377,844,091	2,378,535,570	2,382,445,880	2,385,574,223	2,387,655,523	2,388,264,590	2,388,504,567	2,389,076,808	2,391,286,697	2,397,324,884	2,400,670,009	2,174,164,852
Electric Nuclear Production Plant												
Gross Plant Beginning Balance	4,031,276,577	4,031,335,356	4,033,223,821	4,033,693,631	4,034,056,631	4,044,452,517	4,045,468,767	4,070,725,915	4,074,255,462	4,078,229,876	4,086,292,548	4,096,651,203
Plant Additions	58,779	1,888,465	469,810	363,000	10,395,886	1,016,250	25,257,149	3,529,547	3,974,414	8,062,672	10,358,655	20,236,270
Retirements	58,779	-	-	-	-	-	-	-	-	-	-	20,236,270
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant	4,031,335,356	4,033,223,821	4,033,693,631	4,034,056,631	4,044,452,517	4,045,468,767	4,070,725,915	4,074,255,462	4,078,229,876	4,086,292,548	4,096,651,203	4,116,887,473
Electric Hydro Production Plant												
Gross Plant Beginning Balance	28,007,730	28,007,745	28,007,760	28,007,781	28,007,816	28,007,948	28,007,975	28,008,000	28,008,049	28,024,897	28,029,222	28,033,485
Plant Additions	15	14	21	35	132	27	25	49	16,848	4,325	4,262	65
Retirements	15	-	-	-	-	-	-	-	-	-	-	65
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant	28,007,745	28,007,760	28,007,781	28,007,816	28,007,948	28,007,975	28,008,000	28,008,049	28,024,897	28,029,222	28,033,485	28,033,549
Electric Other Production Plant												
Gross Plant Beginning Balance	5,465,107,695	5,467,975,583	5,468,217,755	5,466,817,822	5,469,373,250	5,471,453,706	5,474,768,549	5,476,439,545	5,477,687,396	5,483,748,937	5,506,842,630	5,516,679,576
Plant Additions	-	242,172	(1,399,933)	2,555,428	2,080,456	3,314,843	1,670,996	1,247,851	6,061,541	23,093,693	9,836,946	(462,853,037)
Retirements	2,867,888	-	-	-	-	-	-	-	-	-	-	457,253,261
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Other Production Plant	5,467,975,583	5,468,217,755	5,466,817,822	5,469,373,250	5,471,453,706	5,474,768,549	5,476,439,545	5,477,687,396	5,483,748,937	5,506,842,630	5,516,679,576	5,511,079,799
Electric Transmission Plant												
Gross Plant Beginning Balance	4,221,890,099	4,223,437,334	4,231,342,957	4,247,383,135	4,248,449,907	4,263,354,790	4,290,167,661	4,290,823,757	4,295,380,694	4,310,338,532	4,314,314,791	4,316,133,312
Plant Additions	(1,109,317)	9,014,939	17,149,495	2,176,089	16,014,199	27,922,188	1,765,413	5,666,253	16,067,155	5,085,576	2,927,838	(1,109,317)
Retirements	2,656,552	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	111,330,162
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant	4,223,437,334	4,231,342,957	4,247,383,135	4,248,449,907	4,263,354,790	4,290,167,661	4,290,823,757	4,295,380,694	4,310,338,532	4,314,314,791	4,316,133,312	4,426,354,157
Electric Distribution Plant (1)												
Gross Plant Beginning Balance	4,808,914,949	4,843,566,616	4,877,566,168	4,909,263,964	4,942,241,279	4,975,572,619	5,015,878,824	5,051,662,707	5,088,105,617	5,125,242,289	5,176,160,228	5,212,870,983
Plant Additions	(3,294,178)	37,293,729	34,991,974	36,271,493	36,625,518	43,600,382	39,078,061	39,737,087	40,430,850	54,212,116	40,004,932	(3,294,178)
Retirements	37,945,845	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	65,170,089
Transfers & Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
Electric Distribution Plant	4,843,566,616	4,877,566,168	4,909,263,964	4,942,241,279	4,975,572,619	5,015,878,824	5,051,662,707	5,088,105,617	5,125,242,289	5,176,160,228	5,212,870,983	5,274,746,894
Electric General Plant												
Gross Plant Beginning Balance	775,405,029	779,002,445	781,686,400	795,405,321	803,427,505	810,330,095	824,950,436	830,884,931	838,477,997	843,523,061	848,415,936	854,691,631
Plant Additions	3,597,416	2,683,955	13,718,922	8,022,183	6,902,591	14,620,341	5,934,495	7,593,066	5,045,064	4,892,875	6,275,695	46,305,973
Retirements	3,597,416	-	-	-	-	-	-	-	-	-	-	46,305,973
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant	779,002,445	781,686,400	795,405,321	803,427,505	810,330,095	824,950,436	830,884,931	838,477,997	843,523,061	848,415,936	854,691,631	900,997,604
Total Electric Utility	22,197,987,574	22,245,419,458	22,312,845,637	22,364,135,861	22,435,024,318	22,522,935,599	22,592,899,379	22,646,849,881	22,716,444,727	22,813,434,996	22,881,855,810	22,901,316,480

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
Gross Plant Beginning Balance	635,549,985	635,484,187	635,902,089	637,429,278	637,700,546	637,934,214	638,598,633	639,007,224	640,348,501	641,663,136	642,708,389	644,892,482
Plant Additions	(65,798)	417,901	1,527,189	271,268	233,668	664,420	408,591	1,341,277	1,314,635	1,045,254	2,184,092	86,973,646
Retirements	(65,798)	-	-	-	-	-	-	-	-	-	-	86,973,646
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common Intangible Plant	635,484,187	635,902,089	637,429,278	637,700,546	637,934,214	638,598,633	639,007,224	640,348,501	641,663,136	642,708,389	644,892,482	731,866,128
Common General Plant												
Gross Plant Beginning Balance	479,779,013	480,076,743	480,347,227	484,636,707	487,868,167	488,696,786	497,338,914	498,933,897	537,758,162	546,279,382	550,347,778	553,172,044
Plant Additions	297,730	270,484	4,289,479	3,231,461	828,619	8,642,128	1,594,984	38,824,264	8,521,220	4,068,396	2,824,266	38,685,997
Retirements	297,730	-	-	-	-	-	-	-	-	-	-	38,685,997
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common General Plant	480,076,743	480,347,227	484,636,707	487,868,167	488,696,786	497,338,914	498,933,897	537,758,162	546,279,382	550,347,778	553,172,044	591,858,041
Total Common Utility	1,115,560,931	1,116,249,316	1,122,065,984	1,125,568,713	1,126,631,000	1,135,937,547	1,137,941,121	1,178,106,662	1,187,942,517	1,193,056,167	1,198,064,526	1,323,724,169
Nuclear Fuel												
Gross Plant Beginning Balance	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	3,058,222,364	3,058,223,742	3,058,756,537
Plant Additions	-	-	-	-	-	-	-	-	77,044,566	1,378	532,795	-
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	3,058,222,364	3,058,223,742	3,058,756,537	3,058,756,537
Total Nuclear Fuel	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	2,981,177,798	3,058,222,364	3,058,223,742	3,058,756,537	3,058,756,537
Total Electric Utility, Common Utility, and Nuclear Fuel	26,294,726,302	26,342,846,571	26,416,089,419	26,470,882,372	26,542,833,115	26,640,050,944	26,712,018,298	26,806,134,341	26,962,609,608	27,064,714,905	27,138,676,872	27,283,797,186

Footnotes:

(1) Electric Distribution Plant in the schedule a

	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
Gross Plant Beginning Balance	4,219,938,696	4,252,426,334	4,279,646,669	4,308,032,462	4,337,609,093	4,367,728,594	4,404,593,441	4,436,910,289	4,469,988,065	4,503,743,925	4,551,228,065	4,584,703,519
Plant Additions	35,395,306	30,128,003	31,293,461	32,484,299	33,027,169	39,772,515	35,224,516	35,985,445	36,663,527	50,391,809	36,383,122	60,075,950
Retirements	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)
Transfers & Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
Electric Distribution Plant - MN	4,252,426,334	4,279,646,669	4,308,032,462	4,337,609,093	4,367,728,594	4,404,593,441	4,436,910,289	4,469,988,065	4,503,743,925	4,551,228,065	4,584,703,519	4,641,871,800

Northern States Power Company
Roll Forward by Functional Class
Plant In-Service

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 13 of 36

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Gross Plant Beginning Balance	469,052,150	477,462,055	478,842,845	489,054,609	489,648,385	494,628,482	495,602,883	495,927,613	496,250,343	496,829,690	506,989,200	507,323,488
Plant Additions	8,409,905	1,380,790	10,211,765	593,776	4,980,097	974,401	324,730	322,730	579,347	10,159,509	334,288	15,549,979
Retirements	8,409,905	-	-	-	-	-	-	-	-	-	-	15,549,979
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant	477,462,055	478,842,845	489,054,609	489,648,385	494,628,482	495,602,883	495,927,613	496,250,343	496,829,690	506,989,200	507,323,488	522,873,467
Electric Steam Production Plant												
Gross Plant Beginning Balance	2,174,164,852	2,174,456,141	2,175,782,078	2,178,179,491	2,179,360,984	2,183,466,750	2,184,273,169	2,184,649,945	2,185,079,371	2,186,469,854	2,191,028,087	2,192,273,749
Plant Additions	291,289	1,325,937	2,397,413	1,181,493	4,105,767	806,419	376,777	429,426	1,390,483	4,558,233	1,245,662	1,104,759
Retirements	291,289	-	-	-	-	-	-	-	-	-	-	1,104,759
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant	2,174,456,141	2,175,782,078	2,178,179,491	2,179,360,984	2,183,466,750	2,184,273,169	2,184,649,945	2,185,079,371	2,186,469,854	2,191,028,087	2,192,273,749	2,193,378,507
Electric Nuclear Production Plant												
Gross Plant Beginning Balance	4,116,887,473	4,116,968,989	4,117,034,567	4,135,686,136	4,145,335,987	4,182,949,193	4,187,210,362	4,203,976,319	4,207,261,791	4,208,857,528	4,216,559,086	4,223,874,435
Plant Additions	81,516	65,578	18,651,569	9,649,851	37,613,206	4,261,169	16,765,957	3,285,472	1,595,737	7,701,559	7,315,349	40,178,266
Retirements	81,516	-	-	-	-	-	-	-	-	-	-	40,178,266
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant	4,116,968,989	4,117,034,567	4,135,686,136	4,145,335,987	4,182,949,193	4,187,210,362	4,203,976,319	4,207,261,791	4,208,857,528	4,216,559,086	4,223,874,435	4,264,052,702
Electric Hydro Production Plant												
Gross Plant Beginning Balance	28,033,549	28,033,551	28,033,552	28,033,555	28,033,559	28,033,573	28,033,576	28,033,579	28,033,584	28,033,589	28,033,606	28,033,616
Plant Additions	2	2	2	4	14	3	3	5	5	17	10	7
Retirements	2	-	-	-	-	-	-	-	-	-	-	7
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant	28,033,551	28,033,552	28,033,555	28,033,559	28,033,573	28,033,576	28,033,579	28,033,584	28,033,589	28,033,606	28,033,616	28,033,623
Electric Other Production Plant												
Gross Plant Beginning Balance	5,511,079,799	5,511,956,790	5,513,175,222	5,524,071,917	5,541,258,758	5,546,088,623	5,522,586,046	5,522,928,263	5,523,610,995	5,524,433,469	5,804,035,465	5,745,176,711
Plant Additions	-	1,218,432	10,896,695	17,186,842	4,829,865	1,155,809	342,217	682,733	822,474	279,601,996	130,634,934	-
Retirements	876,991	-	-	-	-	(24,658,386)	-	-	-	-	(189,493,688)	21,913,359
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Other Production Plant	5,511,956,790	5,513,175,222	5,524,071,917	5,541,258,758	5,546,088,623	5,522,586,046	5,522,928,263	5,523,610,995	5,524,433,469	5,804,035,465	5,745,176,711	5,767,090,070
Electric Transmission Plant												
Gross Plant Beginning Balance	4,426,354,157	4,431,841,831	4,440,269,731	4,478,222,368	4,479,663,034	4,485,639,584	4,536,494,278	4,541,849,542	4,542,247,108	4,574,894,266	4,576,294,431	4,577,838,735
Plant Additions	(1,167,539)	9,595,439	39,120,177	2,608,205	7,144,090	52,022,233	6,522,803	1,565,106	33,814,697	2,567,704	2,711,843	(1,167,539)
Retirements	6,655,213	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	94,311,244
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant	4,431,841,831	4,440,269,731	4,478,222,368	4,479,663,034	4,485,639,584	4,536,494,278	4,541,849,542	4,542,247,108	4,574,894,266	4,576,294,431	4,577,838,735	4,670,982,440
Electric Distribution Plant (1)												
Gross Plant Beginning Balance	5,274,746,894	5,314,408,865	5,353,037,092	5,391,261,662	5,437,092,497	5,474,886,774	5,535,598,347	5,574,992,672	5,622,260,575	5,662,465,972	5,727,974,498	5,763,187,031
Plant Additions	(3,344,770)	41,972,997	41,569,340	49,175,605	41,139,047	64,056,343	42,739,095	50,612,673	43,550,167	68,853,296	38,557,303	(3,344,770)
Retirements	43,006,741	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	48,893,565
Transfers & Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Electric Distribution Plant	5,314,408,865	5,353,037,092	5,391,261,662	5,437,092,497	5,474,886,774	5,535,598,347	5,574,992,672	5,622,260,575	5,662,465,972	5,727,974,498	5,763,187,031	5,808,735,826
Electric General Plant												
Gross Plant Beginning Balance	900,997,604	903,510,443	905,906,433	918,562,478	950,619,127	956,490,716	968,555,177	975,115,533	978,608,364	990,262,941	994,673,022	999,222,053
Plant Additions	2,512,839	2,395,990	12,656,045	32,056,649	5,871,589	12,064,461	6,560,356	3,492,831	11,654,577	4,410,081	4,549,031	50,970,358
Retirements	2,512,839	-	-	-	-	-	-	-	-	-	-	50,970,358
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant	903,510,443	905,906,433	918,562,478	950,619,127	956,490,716	968,555,177	975,115,533	978,608,364	990,262,941	994,673,022	999,222,053	1,050,192,411
Total Electric Utility	22,958,638,666	23,012,081,520	23,143,072,216	23,251,012,330	23,352,183,695	23,458,353,836	23,527,473,466	23,583,352,132	23,672,247,309	24,045,587,394	24,036,929,817	24,305,339,046

Functional Class	2023 January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
Gross Plant Beginning Balance	731,866,128	732,592,669	747,034,675	749,452,736	750,371,950	751,348,957	752,366,420	753,412,201	754,477,806	756,204,982	757,305,197	758,412,210
Plant Additions	726,541	14,442,007	2,418,061	919,214	977,007	1,017,463	1,045,782	1,065,605	1,727,176	1,100,214	1,107,014	48,635,849
Retirements	726,541	-	-	-	-	-	-	-	-	-	-	48,635,849
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common Intangible Plant	732,592,669	747,034,675	749,452,736	750,371,950	751,348,957	752,366,420	753,412,201	754,477,806	756,204,982	757,305,197	758,412,210	807,048,060
Common General Plant												
Gross Plant Beginning Balance	591,858,041	593,085,092	594,249,230	600,232,638	601,447,629	602,520,277	608,966,600	610,143,164	611,248,637	640,982,718	642,134,533	644,280,731
Plant Additions	1,227,051	1,164,137	5,983,408	1,214,991	1,072,648	6,446,323	1,176,565	1,105,473	29,734,081	1,151,815	2,146,198	41,291,513
Retirements	1,227,051	-	-	-	-	-	-	-	-	-	-	41,291,513
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common General Plant	593,085,092	594,249,230	600,232,638	601,447,629	602,520,277	608,966,600	610,143,164	611,248,637	640,982,718	642,134,533	644,280,731	685,572,245
Total Common Utility	1,325,677,761	1,341,283,905	1,349,685,374	1,351,819,578	1,353,869,234	1,361,333,020	1,363,555,366	1,365,726,443	1,397,187,700	1,399,439,730	1,402,692,942	1,492,620,304
Nuclear Fuel												
Gross Plant Beginning Balance	3,058,756,537	3,058,756,537	3,058,756,537	3,142,999,811	3,143,310,748	3,144,081,333	3,144,094,552	3,144,094,552	3,216,415,502	3,216,417,240	3,216,966,471	3,216,966,471
Plant Additions	-	-	84,243,274	310,937	770,585	13,219	-	72,320,950	1,738	549,231	-	-
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	3,058,756,537	3,058,756,537	3,142,999,811	3,143,310,748	3,144,081,333	3,144,094,552	3,144,094,552	3,216,415,502	3,216,417,240	3,216,966,471	3,216,966,471	3,216,966,471
Total Nuclear Fuel	3,058,756,537	3,058,756,537	3,142,999,811	3,143,310,748	3,144,081,333	3,144,094,552	3,144,094,552	3,216,415,502	3,216,417,240	3,216,966,471	3,216,966,471	3,216,966,471
Total Electric Utility, Common Utility, and Nuclear Fuel	27,343,072,964	27,412,121,962	27,635,757,400	27,746,142,656	27,850,134,261	27,963,781,408	28,035,123,383	28,165,494,077	28,285,852,249	28,661,993,595	28,656,589,230	29,014,925,821

Footnotes:

(1) Electric Distribution Plant in the schedule a

Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
Gross Plant Beginning Balance	4,641,871,800	4,678,113,111	4,713,499,947	4,748,496,130	4,790,947,557	4,825,507,713	4,869,278,398	4,905,130,125	4,948,942,099	4,985,666,678	5,034,402,990	5,067,221,424
Plant Additions	39,191,437	38,336,963	37,946,310	45,401,553	37,510,283	46,720,812	38,801,854	46,762,100	39,674,706	51,686,439	35,768,561	40,671,387
Retirements	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)
Transfers & Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Electric Distribution Plant - MN	4,678,113,111	4,713,499,947	4,748,496,130	4,790,947,557	4,825,507,713	4,869,278,398	4,905,130,125	4,948,942,099	4,985,666,678	5,034,402,990	5,067,221,424	5,104,942,684

Northern States Power Company
Roll Forward by Functional Class
Plant In-Service

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 15 of 36

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Gross Plant Beginning Balance	522,873,467	528,719,866	528,719,866	531,003,446	531,003,446	531,003,446	531,469,026	531,469,026	531,469,026	531,934,606	531,934,606	531,934,606
Plant Additions	5,846,399	-	2,283,580	-	-	465,580	-	-	465,580	-	-	7,140,755
Retirements	5,846,399	-	-	-	-	-	-	-	-	-	-	7,140,755
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant	528,719,866	528,719,866	531,003,446	531,003,446	531,003,446	531,469,026	531,469,026	531,469,026	531,934,606	531,934,606	531,934,606	539,075,361
Electric Steam Production Plant												
Gross Plant Beginning Balance	2,193,378,507	2,193,647,576	2,196,108,193	2,197,332,870	2,198,102,621	2,199,791,641	2,203,484,814	2,203,961,780	2,204,271,558	2,204,679,252	2,206,540,154	2,207,699,348
Plant Additions	269,069	2,460,616	1,224,678	769,751	1,689,019	3,693,173	476,966	309,777	407,694	1,860,902	1,159,195	3,269,490
Retirements	269,069	-	-	-	-	-	-	-	-	-	-	3,269,490
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant	2,193,647,576	2,196,108,193	2,197,332,870	2,198,102,621	2,199,791,641	2,203,484,814	2,203,961,780	2,204,271,558	2,204,679,252	2,206,540,154	2,207,699,348	2,210,968,838
Electric Nuclear Production Plant												
Gross Plant Beginning Balance	4,264,052,702	4,264,062,522	4,264,068,526	4,265,034,369	4,265,058,237	4,265,076,137	4,265,300,351	4,265,484,178	4,265,941,983	4,270,949,743	4,278,558,693	4,286,578,557
Plant Additions	9,820	6,004	965,843	23,868	17,900	224,214	183,827	457,805	5,007,760	7,608,950	8,019,864	33,290,527
Retirements	9,820	-	-	-	-	-	-	-	-	-	-	33,290,527
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant	4,264,062,522	4,264,068,526	4,265,034,369	4,265,058,237	4,265,076,137	4,265,300,351	4,265,484,178	4,265,941,983	4,270,949,743	4,278,558,693	4,286,578,557	4,319,869,084
Electric Hydro Production Plant												
Gross Plant Beginning Balance	28,033,623	28,033,623	28,033,623	28,033,624	28,033,624	28,033,626	28,033,626	28,033,626	28,033,627	28,033,627	28,033,629	28,033,630
Plant Additions	0	0	0	0	2	0	0	1	1	2	1	1
Retirements	0	-	-	-	-	-	-	-	-	-	-	1
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant	28,033,623	28,033,623	28,033,624	28,033,624	28,033,626	28,033,626	28,033,626	28,033,627	28,033,627	28,033,629	28,033,630	28,033,631
Electric Other Production Plant												
Gross Plant Beginning Balance	5,767,090,070	5,767,844,849	5,768,467,070	5,772,085,175	5,772,782,167	5,774,119,658	5,774,458,094	5,783,641,695	5,785,191,414	5,789,589,381	6,086,203,511	6,108,885,915
Plant Additions	754,778	622,221	3,618,106	696,992	1,337,491	338,436	9,183,601	1,549,720	4,397,966	296,614,130	22,682,405	10,698,801
Retirements	754,778	-	-	-	-	-	-	-	-	-	-	10,698,801
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Other Production Plant	5,767,844,849	5,768,467,070	5,772,085,175	5,772,782,167	5,774,119,658	5,774,458,094	5,783,641,695	5,785,191,414	5,789,589,381	6,086,203,511	6,108,885,915	6,119,584,716
Electric Transmission Plant												
Gross Plant Beginning Balance	4,670,982,440	4,676,087,583	4,676,126,639	4,700,403,015	4,700,186,183	4,699,969,350	4,742,387,048	4,742,764,339	4,743,048,130	4,778,922,906	4,778,859,119	4,778,931,331
Plant Additions	(1,238,105)	1,277,162	25,514,482	1,021,272	1,021,272	43,655,804	1,615,396	1,521,896	37,112,881	1,174,319	1,310,318	(1,238,105)
Retirements	6,343,248	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	84,082,476
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant	4,676,087,583	4,676,126,639	4,700,403,015	4,700,186,183	4,699,969,350	4,742,387,048	4,742,764,339	4,743,048,130	4,778,922,906	4,778,859,119	4,778,931,331	4,861,775,702
Electric Distribution Plant (1)												
Gross Plant Beginning Balance	5,808,735,826	5,846,082,684	5,883,036,870	5,919,938,799	5,957,109,830	5,994,044,542	6,041,868,108	6,080,572,662	6,119,900,491	6,155,223,282	6,233,899,120	6,266,780,480
Plant Additions	(3,420,719)	40,374,905	40,322,647	40,591,750	40,355,430	51,244,285	42,125,272	42,748,547	38,743,510	82,096,556	36,302,079	(3,420,719)
Retirements	40,767,576	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	49,232,215
Transfers & Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
Electric Distribution Plant	5,846,082,684	5,883,036,870	5,919,938,799	5,957,109,830	5,994,044,542	6,041,868,108	6,080,572,662	6,119,900,491	6,155,223,282	6,233,899,120	6,266,780,480	6,312,591,976
Electric General Plant												
Gross Plant Beginning Balance	1,050,192,411	1,052,505,939	1,055,139,054	1,065,032,983	1,071,030,450	1,077,752,709	1,089,430,684	1,095,222,434	1,104,420,620	1,117,888,492	1,122,496,101	1,151,942,947
Plant Additions	2,313,528	2,633,114	9,893,930	5,997,467	6,722,259	11,677,976	5,791,749	9,198,186	13,467,872	4,607,609	29,446,846	38,022,585
Retirements	2,313,528	-	-	-	-	-	-	-	-	-	-	38,022,585
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant	1,052,505,939	1,055,139,054	1,065,032,983	1,071,030,450	1,077,752,709	1,089,430,684	1,095,222,434	1,104,420,620	1,117,888,492	1,122,496,101	1,151,942,947	1,189,965,533
Total Electric Utility	24,356,984,641	24,399,699,840	24,478,864,282	24,523,306,558	24,569,791,108	24,676,431,753	24,731,149,740	24,782,276,849	24,877,221,289	25,266,524,932	25,360,786,815	25,581,864,841

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Common Intangible Plant												
Gross Plant Beginning Balance	807,048,060	808,302,201	809,704,852	811,211,591	812,790,458	815,057,821	816,723,018	818,402,712	820,099,900	821,809,334	823,527,340	825,251,347
Plant Additions	1,254,141	1,402,651	1,506,740	1,578,866	2,267,363	1,665,197	1,679,694	1,697,188	1,709,434	1,718,006	1,724,007	24,930,647
Retirements	1,254,141	-	-	-	-	-	-	-	-	-	-	24,930,647
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common Intangible Plant	808,302,201	809,704,852	811,211,591	812,790,458	815,057,821	816,723,018	818,402,712	820,099,900	821,809,334	823,527,340	825,251,347	850,181,994
Common General Plant												
Gross Plant Beginning Balance	685,572,245	686,477,413	687,351,936	693,879,918	694,782,765	695,781,929	702,326,343	703,342,760	704,368,774	710,901,095	712,128,332	713,099,948
Plant Additions	905,169	874,522	6,527,982	902,846	999,165	6,544,413	1,016,417	1,026,015	6,532,321	1,227,237	971,615	18,711,959
Retirements	905,169	-	-	-	-	-	-	-	-	-	-	18,711,959
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Common General Plant	686,477,413	687,351,936	693,879,918	694,782,765	695,781,929	702,326,343	703,342,760	704,368,774	710,901,095	712,128,332	713,099,948	731,811,906
Total Common Utility	1,494,779,614	1,497,056,788	1,505,091,510	1,507,573,222	1,510,839,750	1,519,049,361	1,521,745,471	1,524,468,674	1,532,710,429	1,535,655,672	1,538,351,294	1,581,993,900
Nuclear Fuel												
Gross Plant Beginning Balance	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,287,237,448	3,287,238,923	3,287,808,233
Plant Additions	-	-	-	-	-	-	-	-	70,270,977	1,475	569,310	-
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,287,237,448	3,287,238,923	3,287,808,233	3,287,808,233
Total Nuclear Fuel	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,216,966,471	3,287,237,448	3,287,238,923	3,287,808,233	3,287,808,233
Total Electric Utility, Common Utility, and Nuclear Fuel	29,068,730,726	29,113,723,099	29,200,922,262	29,247,846,252	29,297,597,329	29,412,447,584	29,469,861,683	29,523,711,994	29,697,169,166	30,089,419,528	30,186,946,342	30,451,666,974

Footnotes:

(1) Electric Distribution Plant in the schedule a

Electric Distribution Plant - MN												
Gross Plant Beginning Balance	5,104,942,684	5,140,457,522	5,175,619,432	5,210,753,606	5,246,172,142	5,281,343,189	5,323,795,030	5,360,588,937	5,397,933,572	5,431,249,128	5,507,881,837	5,538,927,727
Plant Additions	38,519,518	38,166,590	38,138,854	38,423,217	38,175,727	45,456,520	39,798,588	40,349,315	36,320,236	79,637,389	34,050,570	46,920,732
Retirements	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)
Transfers & Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
Electric Distribution Plant - MN	5,140,457,522	5,175,619,432	5,210,753,606	5,246,172,142	5,281,343,189	5,323,795,030	5,360,588,937	5,397,933,572	5,431,249,128	5,507,881,837	5,538,927,727	5,582,843,779

	2021											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Accumulated Depreciation Beginning Balance	223,421,066	225,461,703	227,546,272	229,573,282	231,667,038	233,760,709	235,908,709	238,093,732	240,318,214	242,588,364	244,883,660	247,175,157
Book Depreciation	2,084,466	2,084,577	2,027,395	2,092,412	2,094,027	2,135,060	2,185,670	2,227,398	2,272,998	2,294,713	2,293,488	2,683,526
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(43,829)	(8)	(385)	1,345	(356)	12,939	(647)	(2,917)	(2,848)	582	(1,991)	(3,236)
Electric Intangible Plant	225,461,703	227,546,272	229,573,282	231,667,038	233,760,709	235,908,709	238,093,732	240,318,214	242,588,364	244,883,660	247,175,157	249,855,447
Electric Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Electric Intangible including RWIP	225,461,703	227,546,272	229,573,282	231,667,038	233,760,709	235,908,709	238,093,732	240,318,214	242,588,364	244,883,660	247,175,157	249,855,447
Electric Steam Production Plant												
Accumulated Depreciation Beginning Balance	1,664,792,958	1,673,332,509	1,675,912,526	1,684,477,780	1,693,082,931	1,701,902,187	1,708,123,826	1,714,268,672	1,722,727,190	1,731,509,823	1,740,134,122	1,745,180,555
Book Depreciation	8,539,470	8,547,987	8,564,926	8,604,236	8,678,360	8,726,821	8,750,183	8,778,422	8,845,458	8,933,490	9,013,029	9,085,906
Retirements	-	(4,306,129)	-	-	(35,751)	(1,968,974)	-	-	-	-	-	-
Book Removals	-	(1,661,768)	58	(2)	(12,795)	(537,209)	(2,629,793)	(440,733)	(72,352)	(343,452)	(3,987,386)	(444,403)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	(302)	-	-	188,690	926	24,328	120,770	9,486	34,150	20,490	13,831
Transfers & Adjustments	82	227	270	918	751	77	128	59	41	112	300	295
Electric Steam Production Plant	1,673,332,509	1,675,912,526	1,684,477,780	1,693,082,931	1,701,902,187	1,708,123,826	1,714,268,672	1,722,727,190	1,731,509,823	1,740,134,122	1,745,180,555	1,753,836,184
Electric Steam Production Plant RWIP	8,501,758	7,531,608	8,125,772	8,106,919	7,939,278	8,147,649	6,146,330	6,143,419	6,064,581	6,051,672	2,196,758	1,893,334
Total Electric Steam Production including RWIP	1,664,830,752	1,668,380,917	1,676,352,007	1,684,976,013	1,693,962,909	1,699,976,177	1,708,122,342	1,716,583,771	1,725,445,242	1,734,082,451	1,742,983,797	1,751,942,850
Electric Nuclear Production Plant												
Accumulated Depreciation Beginning Balance	2,073,302,314	2,086,722,026	2,098,486,108	2,111,914,417	2,125,198,439	2,138,806,514	2,152,528,496	2,165,903,304	2,178,016,726	2,191,093,678	2,204,803,573	2,218,596,958
Book Depreciation	13,419,700	13,424,925	13,428,324	13,464,554	13,608,054	13,721,979	13,748,555	13,789,012	13,869,957	13,968,089	14,033,031	14,105,960
Retirements	-	(1,471,179)	-	(111,406)	-	-	-	-	-	-	-	-
Book Removals	9	(189,666)	(18)	(69,127)	18	-	(432,133)	(1,675,592)	(793,007)	(258,195)	(239,648)	(903,765)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	58,385	-	-	-	-	-
Transfers & Adjustments	2	2	2	2	2	2	2	2	2	2	2	2
Electric Nuclear Production Plant	2,086,722,026	2,098,486,108	2,111,914,417	2,125,198,439	2,138,806,514	2,152,528,496	2,165,903,304	2,178,016,726	2,191,093,678	2,204,803,573	2,218,596,958	2,231,799,155
Electric Nuclear Production Plant RWIP	4,130,899	4,579,837	5,238,480	5,943,897	3,910,480	4,167,203	4,004,541	2,375,780	2,116,794	2,251,933	2,119,490	1,661,606
Total Electric Nuclear Production including RWIP	2,082,591,127	2,093,906,271	2,106,675,937	2,119,254,542	2,134,896,034	2,148,361,293	2,161,898,763	2,175,640,946	2,188,976,883	2,202,551,640	2,216,477,468	2,230,137,549
Electric Hydro Production Plant												
Accumulated Depreciation Beginning Balance	16,185,657	16,307,049	16,428,501	16,549,984	16,671,465	16,792,945	16,914,426	17,010,182	17,132,139	17,254,103	17,375,989	17,498,202
Book Depreciation	121,363	121,422	121,453	121,451	121,451	121,451	121,721	121,994	121,998	122,007	122,286	122,597
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	(25,965)	(37)	(34)	(121)	(73)	(10,049)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	29	30	30	30	30	30	(0)	(0)	(0)	(0)	(0)	(0)
Electric Hydro Production Plant	16,307,049	16,428,501	16,549,984	16,671,465	16,792,945	16,914,426	17,010,182	17,132,139	17,254,103	17,375,989	17,498,202	17,610,750
Electric Hydro Production Plant RWIP	25,056	23,935	24,628	25,127	26,560	27,650	1,685	1,648	1,614	9,493	10,921	1,372
Total Electric Hydro Production including RWIP	16,281,993	16,404,566	16,525,356	16,646,337	16,766,385	16,886,776	17,008,497	17,130,491	17,252,489	17,366,496	17,487,281	17,609,379
Electric Other Production Plant												
Accumulated Depreciation Beginning Balance	1,124,307,245	1,138,302,700	1,146,413,460	1,226,533,585	1,241,666,877	1,257,407,699	1,271,847,041	1,287,147,649	1,303,559,019	1,319,968,840	1,335,041,009	1,351,320,212
Book Depreciation	13,995,258	14,556,932	14,902,860	15,192,434	15,791,737	16,455,066	16,493,987	16,483,971	16,518,663	16,562,751	16,607,827	17,367,579
Retirements	-	(4,736,852)	-	(40,264)	(41,679)	(1,941,851)	-	-	-	-	-	-
Book Removals	-	(1,720,978)	(251,973)	(19,137)	(9,491)	(74,074)	(1,193,406)	(72,603)	(79,931)	(1,490,640)	(325,449)	(1,113,477)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	11,404	-	-	-	-	-	-	(28,916)	-	(3,195)	185,198
Transfers & Adjustments	197	254	65,469,238	258	257	201	27	3	5	58	21	19
Electric Other Production Plant	1,138,302,700	1,146,413,460	1,226,533,585	1,241,666,877	1,257,407,699	1,271,847,041	1,287,147,649	1,303,559,019	1,319,968,840	1,335,041,009	1,351,320,212	1,367,759,531
Electric Other Production Plant RWIP	23,148,651	22,471,670	33,046,491	23,442,782	24,022,281	22,257,835	21,198,057	21,391,995	22,214,241	21,532,986	21,258,870	20,563,337
Total Electric Other Production including RWIP	1,115,154,049	1,123,941,791	1,193,487,093	1,218,224,094	1,233,385,418	1,249,589,207	1,265,949,592	1,282,167,024	1,297,754,600	1,313,508,024	1,330,061,342	1,347,196,195
Electric Transmission Plant												
Accumulated Depreciation Beginning Balance	1,038,112,998	1,044,639,568	1,048,330,550	1,054,635,934	1,056,211,025	1,062,804,202	1,063,454,984	1,060,465,017	1,065,091,684	1,067,768,263	1,072,168,815	1,077,912,873
Book Depreciation	6,528,434	6,549,955	6,552,662	6,573,809	6,602,338	6,637,322	6,656,349	6,673,018	6,692,634	6,718,741	6,733,047	6,892,096
Retirements	-	(1,340,459)	(139,665)	(3,394,391)	-	(2,552,600)	(963,942)	(963,942)	(963,942)	(963,942)	(963,942)	(963,942)
Book Removals	(1,462)	(1,525,898)	(107,596)	(1,674,799)	(6,059)	(3,466,153)	(9,165,303)	(1,104,235)	(3,038,255)	(1,349,163)	(25,030)	(2,900,176)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	7,789	-	70,494	(3,085)	32,233	482,954	21,844	(13,839)	(5,065)	-	2,405
Transfers & Adjustments	(402)	(405)	(17)	(21)	(17)	(22)	(25)	(18)	(20)	(18)	(17)	(20)
Electric Transmission Plant	1,044,639,568	1,048,330,550	1,054,635,934	1,056,211,025	1,062,804,202	1,063,454,984	1,060,465,017	1,065,091,684	1,067,768,263	1,072,168,815	1,077,912,873	1,080,943,236
Electric Transmission Plant RWIP	29,038,955	28,648,036	30,316,731	30,317,775	31,506,725	24,768,976	16,217,937	15,414,286	12,559,698	11,430,833	11,583,484	8,875,702
Total Electric Transmission including RWIP	1,015,600,613	1,019,682,514	1,024,319,203	1,025,893,250	1,031,297,478	1,038,686,007	1,044,247,080	1,049,677,399	1,055,208,565	1,060,737,982	1,066,329,390	1,072,067,534

	2021											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant (1)												
Accumulated Depreciation Beginning Balance	1,736,717,707	1,745,489,144	1,751,986,617	1,760,635,321	1,767,901,856	1,776,613,880	1,762,437,140	1,769,911,040	1,777,174,267	1,784,134,017	1,791,230,141	1,797,244,448
Book Depreciation	10,548,508	10,590,364	10,738,362	10,715,039	10,774,979	10,776,885	10,803,319	10,852,627	10,907,110	10,964,380	11,019,329	11,140,909
Retirements	(96,952)	(1,838,894)	(580,352)	(1,176,705)	(916,889)	(23,467,489)	(2,093,151)	(2,180,054)	(2,180,054)	(2,180,054)	(2,180,054)	(2,180,054)
Book Removals	(1,725,000)	(2,277,878)	(1,510,485)	(2,273,789)	(1,149,277)	(1,496,196)	(8,639,201)	(3,394,852)	(2,359,173)	(1,888,221)	(2,919,775)	(1,628,359)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	44,881	23,881	1,179	1,990	3,211	10,060	7,402,932	1,985,507	591,867	200,019	94,806	34,992
Transfers & Adjustments	-	-	-	-	(0)	-	-	-	-	-	-	-
Electric Distribution Plant	1,745,489,144	1,751,986,617	1,760,635,321	1,767,901,856	1,776,613,880	1,762,437,140	1,769,911,040	1,777,174,267	1,784,134,017	1,791,230,141	1,797,244,448	1,804,611,935
Electric Distribution Plant RWIP	8,009,459	6,662,179	6,830,865	6,945,442	7,440,282	6,888,897	7,230,574	7,435,825	7,196,455	6,955,270	5,455,347	5,158,155
Total Electric Distribution including RWIP	1,737,479,685	1,745,324,438	1,753,804,456	1,760,956,414	1,769,173,598	1,755,548,243	1,762,680,465	1,769,738,443	1,776,937,563	1,784,274,871	1,791,789,100	1,799,453,780
Electric General Plant												
Accumulated Depreciation Beginning Balance	321,763,144	325,222,409	328,656,830	328,138,538	331,905,761	335,919,186	329,667,586	334,992,536	339,133,397	343,301,055	347,502,902	351,633,100
Book Depreciation	3,463,136	3,477,894	3,589,564	3,774,081	3,988,630	4,041,463	4,122,843	4,161,752	4,181,706	4,193,874	4,254,559	4,375,001
Retirements	-	(21,520)	(4,120,540)	-	-	(10,565,213)	-	-	-	-	-	-
Book Removals	(3,430)	(16,784)	-	(32,166)	-	-	(774,835)	(28,843)	(20,982)	(15,598)	(153,101)	(17,981)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	249,350	1,953,751	28	20	14	10	7
Transfers & Adjustments	(441)	(5,169)	12,684	25,308	24,795	22,800	23,192	7,924	6,914	23,557	28,730	22,479
Electric General Plant	325,222,409	328,656,830	328,138,538	331,905,761	335,919,186	329,667,586	334,992,536	339,133,397	343,301,055	347,502,902	351,633,100	356,012,606
Electric General Plant RWIP	(496,663)	(622,623)	(643,237)	(762,368)	(765,915)	(473,723)	760,184	787,075	821,277	855,383	731,854	756,916
Total Electric General including RWIP	325,719,072	329,279,453	328,781,775	332,668,129	336,685,101	330,141,308	334,232,352	338,346,322	342,479,779	346,647,519	350,901,246	355,255,690
Total Electric Utility	8,255,477,108	8,293,760,864	8,412,458,839	8,464,305,392	8,524,007,323	8,540,882,208	8,587,792,133	8,643,152,637	8,697,618,143	8,753,140,211	8,806,561,505	8,862,428,845
Total Electric Utility RWIP	72,358,114	69,294,642	82,939,730	74,019,575	74,079,691	65,784,488	55,559,309	53,550,027	50,974,659	49,087,569	43,356,724	38,910,422
Total Electric Utility including RWIP	8,183,118,994	8,224,466,223	8,329,519,108	8,390,285,817	8,449,927,633	8,475,097,720	8,532,232,824	8,589,602,610	8,646,643,484	8,704,052,642	8,763,204,781	8,823,518,423
Common Intangible Plant												
Accumulated Depreciation Beginning Balance	280,141,909	284,532,195	289,007,533	293,411,476	297,887,603	302,321,628	306,739,993	311,220,803	315,578,365	319,902,332	324,104,420	328,422,895
Book Depreciation	4,389,909	4,476,122	4,401,534	4,479,118	4,433,684	4,416,628	4,464,484	4,368,980	4,322,569	4,202,471	4,326,464	5,514,361
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	377	(784)	2,409	(2,991)	340	1,737	16,326	(11,418)	1,398	(383)	(7,989)	2,708
Common Intangible Plant	284,532,195	289,007,533	293,411,476	297,887,603	302,321,628	306,739,993	311,220,803	315,578,365	319,902,332	324,104,420	328,422,895	333,939,964
Common Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Common Intangible including RWIP	284,532,195	289,007,533	293,411,476	297,887,603	302,321,628	306,739,993	311,220,803	315,578,365	319,902,332	324,104,420	328,422,895	333,939,964
Common General Plant												
Accumulated Depreciation Beginning Balance	129,456,189	132,622,559	136,080,127	137,843,088	141,257,995	144,628,338	136,576,275	139,305,265	142,667,652	145,921,931	149,231,975	152,573,542
Book Depreciation	3,109,921	3,413,263	3,351,476	3,355,054	3,366,694	3,637,331	3,341,579	3,347,346	3,443,902	3,497,773	3,495,178	3,467,920
Retirements	-	(31,186)	(1,654,817)	-	-	(13,727,239)	-	-	-	-	-	-
Book Removals	(1,405)	-	(2)	-	-	(19,796)	(744,020)	(29,762)	(201,589)	(20,400)	(17,530)	(46,012)
Gain/Loss	-	-	2	-	-	26,518	-	-	-	-	-	-
Salvage	-	712	-	-	-	2,090,601	105,922	7,752	5,814	4,360	3,270	2,453
Transfers & Adjustments	57,853	74,778	66,302	59,852	3,649	(59,478)	25,509	37,050	6,152	(171,690)	(139,352)	58,454
Common General Plant	132,622,559	136,080,127	137,843,088	141,257,995	144,628,338	136,576,275	139,305,265	142,667,652	145,921,931	149,231,975	152,573,542	156,056,357
Common General Plant RWIP	(854,639)	(794,143)	(783,454)	(709,957)	(576,118)	1,729,431	1,128,982	1,156,235	1,062,582	1,325,256	1,583,930	1,806,172
Total Common General including RWIP	133,477,198	136,874,270	138,626,542	141,967,951	145,204,456	134,846,844	138,176,283	141,511,416	144,859,349	147,906,719	150,989,612	154,250,184
Total Common Utility	417,154,754	425,087,660	431,254,565	439,145,598	446,949,966	443,316,267	450,526,068	458,246,017	465,824,263	473,336,395	480,996,437	489,996,320
Total Common Utility RWIP	(854,639)	(794,143)	(783,454)	(709,957)	(576,118)	1,729,431	1,128,982	1,156,235	1,062,582	1,325,256	1,583,930	1,806,172
Total Common Utility including RWIP	418,009,393	425,881,803	432,038,019	439,855,555	447,526,084	441,586,837	449,397,085	457,089,781	464,761,681	472,011,139	479,412,507	488,190,148

Functional Class	2021 January	February	March	April	May	June	July	August	September	October	November	December
Nuclear Fuel												
Accumulated Depreciation Beginning Balance	2,659,339,314	2,669,734,144	2,679,169,269	2,689,284,796	2,697,442,658	2,705,468,741	2,715,479,170	2,725,588,862	2,735,698,554	2,745,014,913	2,752,170,108	2,762,160,655
Book Depreciation	10,394,830	9,435,125	10,115,527	8,157,863	8,026,082	10,010,429	10,109,692	10,109,692	9,316,359	7,155,195	9,990,547	10,370,761
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	2,669,734,144	2,679,169,269	2,689,284,796	2,697,442,658	2,705,468,741	2,715,479,170	2,725,588,862	2,735,698,554	2,745,014,913	2,752,170,108	2,762,160,655	2,772,531,416
Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	2,669,734,144	2,679,169,269	2,689,284,796	2,697,442,658	2,705,468,741	2,715,479,170	2,725,588,862	2,735,698,554	2,745,014,913	2,752,170,108	2,762,160,655	2,772,531,416
Total Nuclear Fuel	2,669,734,144	2,679,169,269	2,689,284,796	2,697,442,658	2,705,468,741	2,715,479,170	2,725,588,862	2,735,698,554	2,745,014,913	2,752,170,108	2,762,160,655	2,772,531,416
Total Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	2,669,734,144	2,679,169,269	2,689,284,796	2,697,442,658	2,705,468,741	2,715,479,170	2,725,588,862	2,735,698,554	2,745,014,913	2,752,170,108	2,762,160,655	2,772,531,416
Decommissioning												
Accumulated Depreciation Beginning Balance	1,774,157,330	1,775,854,976	1,792,556,620	1,806,032,823	1,807,730,469	1,805,158,707	1,825,371,001	1,827,068,646	1,828,766,291	1,830,463,936	1,832,161,581	1,833,859,226
Book Depreciation	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645	1,697,645
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	15,003,999	11,778,558	-	(4,269,407)	18,514,648	-	-	-	-	-	-
Decommissioning	1,775,854,976	1,792,556,620	1,806,032,823	1,807,730,469	1,805,158,707	1,825,371,001	1,827,068,646	1,828,766,291	1,830,463,936	1,832,161,581	1,833,859,226	1,835,556,871
Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,775,854,976	1,792,556,620	1,806,032,823	1,807,730,469	1,805,158,707	1,825,371,001	1,827,068,646	1,828,766,291	1,830,463,936	1,832,161,581	1,833,859,226	1,835,556,871
Total Decommissioning	1,775,854,976	1,792,556,620	1,806,032,823	1,807,730,469	1,805,158,707	1,825,371,001	1,827,068,646	1,828,766,291	1,830,463,936	1,832,161,581	1,833,859,226	1,835,556,871
Total Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,775,854,976	1,792,556,620	1,806,032,823	1,807,730,469	1,805,158,707	1,825,371,001	1,827,068,646	1,828,766,291	1,830,463,936	1,832,161,581	1,833,859,226	1,835,556,871
NSPM Theoretical Reserve - Distribution												
Accumulated Depreciation Beginning Balance	(86,902,719)	(86,434,810)	(85,966,901)	(85,498,992)	(85,031,083)	(84,563,174)	(84,095,265)	(83,627,356)	(83,159,447)	(82,691,538)	(82,223,629)	(81,755,720)
Book Depreciation	467,909	467,909	467,909	467,909	467,909	467,909	467,909	467,909	467,909	467,909	467,909	467,909
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(86,434,810)	(85,966,901)	(85,498,992)	(85,031,083)	(84,563,174)	(84,095,265)	(83,627,356)	(83,159,447)	(82,691,538)	(82,223,629)	(81,755,720)	(81,287,811)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(86,434,810)	(85,966,901)	(85,498,992)	(85,031,083)	(84,563,174)	(84,095,265)	(83,627,356)	(83,159,447)	(82,691,538)	(82,223,629)	(81,755,720)	(81,287,811)
NSPM Theoretical Reserve - Transmission												
Accumulated Depreciation Beginning Balance	(135,435,078)	(135,140,030)	(134,844,982)	(134,549,933)	(134,254,885)	(133,959,837)	(133,664,789)	(133,369,740)	(133,074,692)	(132,779,644)	(132,484,595)	(132,189,547)
Book Depreciation	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(135,140,030)	(134,844,982)	(134,549,933)	(134,254,885)	(133,959,837)	(133,664,789)	(133,369,740)	(133,074,692)	(132,779,644)	(132,484,595)	(132,189,547)	(131,894,499)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(135,140,030)	(134,844,982)	(134,549,933)	(134,254,885)	(133,959,837)	(133,664,789)	(133,369,740)	(133,074,692)	(132,779,644)	(132,484,595)	(132,189,547)	(131,894,499)

Functional Class	2021 January	February	March	April	May	June	July	August	September	October	November	December
NSPM Theoretical Reserve - General and Intangible												
Accumulated Depreciation Beginning Balance	(1,275,314)	(1,254,402)	(1,233,490)	(1,212,578)	(1,191,665)	(1,170,753)	(1,149,841)	(1,128,929)	(1,108,017)	(1,087,105)	(1,066,193)	(1,045,281)
Book Depreciation	20,912	20,912	20,912	20,912	20,912	20,912	20,912	20,912	20,912	20,912	20,912	20,912
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(1,254,402)	(1,233,490)	(1,212,578)	(1,191,665)	(1,170,753)	(1,149,841)	(1,128,929)	(1,108,017)	(1,087,105)	(1,066,193)	(1,045,281)	(1,024,369)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(1,254,402)	(1,233,490)	(1,212,578)	(1,191,665)	(1,170,753)	(1,149,841)	(1,128,929)	(1,108,017)	(1,087,105)	(1,066,193)	(1,045,281)	(1,024,369)
Total NSPM Theoretical Reserve	(222,829,242)	(222,045,373)	(221,261,503)	(220,477,634)	(219,693,764)	(218,909,895)	(218,126,025)	(217,342,156)	(216,558,286)	(215,774,417)	(214,990,548)	(214,206,678)
Total NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(222,829,242)	(222,045,373)	(221,261,503)	(220,477,634)	(219,693,764)	(218,909,895)	(218,126,025)	(217,342,156)	(216,558,286)	(215,774,417)	(214,990,548)	(214,206,678)
Sherco Reg Asset												
Accumulated Depreciation Beginning Balance	(7,043,816)	(7,001,888)	(6,959,961)	(6,918,033)	(6,876,106)	(6,834,178)	(6,792,251)	(6,750,323)	(6,708,396)	(6,666,469)	(6,624,541)	(6,582,614)
Book Depreciation	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Sherco Reg Asset	(7,001,888)	(6,959,961)	(6,918,033)	(6,876,106)	(6,834,178)	(6,792,251)	(6,750,323)	(6,708,396)	(6,666,469)	(6,624,541)	(6,582,614)	(6,540,686)
Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(7,001,888)	(6,959,961)	(6,918,033)	(6,876,106)	(6,834,178)	(6,792,251)	(6,750,323)	(6,708,396)	(6,666,469)	(6,624,541)	(6,582,614)	(6,540,686)
Total Sherco Reg Asset Reserve	(7,001,888)	(6,959,961)	(6,918,033)	(6,876,106)	(6,834,178)	(6,792,251)	(6,750,323)	(6,708,396)	(6,666,469)	(6,624,541)	(6,582,614)	(6,540,686)
Total Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(7,001,888)	(6,959,961)	(6,918,033)	(6,876,106)	(6,834,178)	(6,792,251)	(6,750,323)	(6,708,396)	(6,666,469)	(6,624,541)	(6,582,614)	(6,540,686)
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets	12,888,389,851	12,961,569,079	13,110,851,486	13,181,270,378	13,255,056,795	13,299,346,501	13,366,099,359	13,441,812,946	13,515,696,499	13,588,409,337	13,662,004,662	13,739,766,087
Removal Work in Process (RWIP)	71,503,475	68,500,498	82,156,276	73,309,619	73,503,573	67,513,919	56,688,291	54,706,263	52,037,240	50,412,825	44,940,654	40,716,594
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets including RWIP	12,816,886,377	12,893,068,581	13,028,695,210	13,107,960,759	13,181,553,222	13,231,832,582	13,309,411,069	13,387,106,684	13,463,659,259	13,537,996,512	13,617,064,008	13,699,049,493

Footnotes:
(1) Electric Distribution Plant in the schedule above contains NSPM total company all jurisdictions. Below is the Electric Distribution State of MN only

Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
Accumulated Depreciation Beginning Balance	1,463,608,793	1,471,758,825	1,477,793,762	1,485,727,420	1,492,276,500	1,500,330,260	1,487,118,333	1,494,997,724	1,502,014,627	1,508,727,159	1,515,590,067	1,521,346,540
Book Depreciation	9,694,897	9,729,502	9,873,468	9,845,961	9,901,920	9,901,711	9,919,173	9,960,357	10,007,904	10,057,475	10,105,358	10,220,068
Retirements	(58,297)	(1,687,387)	(536,227)	(1,146,200)	(791,542)	(21,812,555)	(1,682,387)	(1,769,290)	(1,769,290)	(1,769,290)	(1,769,290)	(1,769,290)
Book Removals	(1,489,294)	(2,029,463)	(1,404,760)	(2,152,671)	(1,059,829)	(1,311,141)	(7,729,837)	(3,143,806)	(2,109,857)	(1,621,288)	(2,672,507)	(1,373,223)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	2,726	22,285	1,176	1,990	3,211	10,058	7,372,443	1,969,642	583,775	196,012	92,913	34,168
Transfers & Adjustments	-	-	-	-	(0)	-	-	-	-	-	-	-
Electric Distribution Plant - MN	1,471,758,825	1,477,793,762	1,485,727,420	1,492,276,500	1,500,330,260	1,487,118,333	1,494,997,724	1,502,014,627	1,508,727,159	1,515,590,067	1,521,346,540	1,528,458,262
Electric Distribution Plant - MN RWIP	6,924,912	5,702,440	5,769,570	5,798,014	6,210,401	5,638,526	6,678,686	6,855,249	6,578,151	6,290,579	4,717,080	4,359,992
Total Electric Distribution - MN including RWIP	1,464,833,913	1,472,091,322	1,479,957,850	1,486,478,486	1,494,119,859	1,481,479,807	1,488,319,039	1,495,159,378	1,502,149,008	1,509,299,487	1,516,629,460	1,524,098,270

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Accumulated Depreciation Beginning Balance	249,855,447	252,527,169	255,195,426	257,879,416	260,591,075	263,305,122	266,038,145	268,760,388	271,460,352	274,144,456	276,825,986	279,475,660
Book Depreciation	2,670,718	2,663,398	2,666,041	2,709,203	2,717,731	2,728,396	2,709,459	2,691,934	2,695,052	2,662,154	2,655,500	2,878,456
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	1,004	4,859	17,949	2,457	(3,684)	4,627	12,783	8,030	(10,948)	19,376	(5,826)	(11,542)
Electric Intangible Plant	252,527,169	255,195,426	257,879,416	260,591,075	263,305,122	266,038,145	268,760,388	271,460,352	274,144,456	276,825,986	279,475,660	282,342,574
Electric Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	14,900	14,900	14,900
Total Electric Intangible including RWIP	252,527,169	255,195,426	257,879,416	260,591,075	263,305,122	266,038,145	268,760,388	271,460,352	274,144,456	276,811,086	279,460,760	282,327,674
Electric Steam Production Plant												
Accumulated Depreciation Beginning Balance	1,753,836,184	1,762,674,326	1,771,232,219	1,780,385,375	1,789,602,526	1,798,809,298	1,807,502,210	1,816,209,938	1,825,255,122	1,834,678,377	1,844,218,075	1,853,776,748
Book Depreciation	9,111,324	9,123,969	9,170,405	9,226,203	9,266,088	9,313,807	9,355,073	9,386,694	9,434,558	9,586,330	9,799,425	10,080,649
Retirements	-	-	-	-	-	-	-	-	-	-	-	(227,911,389)
Book Removals	(273,537)	(566,521)	(18,769)	(11,010)	(62,839)	(621,860)	(648,095)	(342,688)	(12,420)	(50,517)	(243,142)	(1,841,984)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	338	331	487	787	2,992	598	569	1,080	972	3,500	2,100	1,417
Transfers & Adjustments	16	114	1,032	1,172	530	367	181	98	145	386	290	(78,628)
Electric Steam Production Plant	1,762,674,326	1,771,232,219	1,780,385,375	1,789,602,526	1,798,809,298	1,807,502,210	1,816,209,938	1,825,255,122	1,834,678,377	1,844,218,075	1,853,776,748	1,634,026,814
Electric Steam Production Plant RWIP	1,835,467	2,125,864	2,822,759	3,603,382	4,800,639	5,353,216	5,854,165	7,138,482	11,032,420	11,460,105	11,544,629	9,756,349
Total Electric Steam Production including RWIP	1,760,838,859	1,769,106,355	1,777,562,616	1,785,999,145	1,794,008,659	1,802,148,994	1,810,355,773	1,818,116,640	1,823,645,957	1,832,757,971	1,842,232,119	1,624,270,465
Electric Nuclear Production Plant												
Accumulated Depreciation Beginning Balance	2,231,799,155	2,245,948,466	2,259,852,245	2,273,682,089	2,287,538,461	2,299,212,200	2,313,521,463	2,327,901,742	2,342,406,961	2,356,504,956	2,371,090,914	2,385,742,362
Book Depreciation	14,149,309	14,157,263	14,168,332	14,173,975	14,240,032	14,309,260	14,405,278	14,510,217	14,540,002	14,585,957	14,653,445	14,779,254
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	(253,486)	(338,489)	(317,606)	(2,566,295)	-	(25,000)	(5,000)	(442,010)	-	(2,000)	(449,087)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	2	2	2	2	2	2	2	2	2	2	2	2
Electric Nuclear Production Plant	2,245,948,466	2,259,852,245	2,273,682,089	2,287,538,461	2,299,212,200	2,313,521,463	2,327,901,742	2,342,406,961	2,356,504,956	2,371,090,914	2,385,742,362	2,400,072,531
Electric Nuclear Production Plant RWIP	1,925,160	1,930,801	1,670,342	3,339,641	872,099	872,099	874,099	919,099	1,076,769	1,331,669	1,489,669	1,140,583
Total Electric Nuclear Production including RWIP	2,244,023,306	2,257,921,443	2,272,011,747	2,284,198,820	2,298,340,101	2,312,649,364	2,327,027,643	2,341,487,862	2,355,428,186	2,369,759,245	2,384,252,692	2,398,931,949
Electric Hydro Production Plant												
Accumulated Depreciation Beginning Balance	17,610,750	17,733,384	17,856,017	17,978,650	18,101,282	18,223,907	18,346,541	18,469,176	18,591,809	18,714,520	18,837,319	18,960,164
Book Depreciation	122,634	122,635	122,635	122,635	122,636	122,637	122,637	122,637	122,715	122,812	122,852	122,873
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(1)	(1)	(2)	(3)	(11)	(2)	(2)	(4)	(3)	(12)	(7)	(5)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Electric Hydro Production Plant	17,733,384	17,856,017	17,978,650	18,101,282	18,223,907	18,346,541	18,469,176	18,591,809	18,714,520	18,837,319	18,960,164	19,083,032
Electric Hydro Production Plant RWIP	1,371	1,369	1,368	1,365	1,354	1,352	1,350	1,346	1,343	1,331	1,323	1,318
Total Electric Hydro Production including RWIP	17,732,013	17,854,647	17,977,282	18,099,917	18,222,552	18,345,189	18,467,825	18,590,462	18,713,177	18,835,989	18,958,841	19,081,713
Electric Other Production Plant												
Accumulated Depreciation Beginning Balance	1,367,759,531	1,385,555,086	1,403,677,620	1,420,335,362	1,438,454,778	1,456,488,616	1,474,448,131	1,492,476,190	1,510,664,116	1,528,746,820	1,547,030,542	1,565,400,604
Book Depreciation	18,120,608	18,127,701	18,126,828	18,131,461	18,146,462	18,182,032	18,213,695	18,223,267	18,241,249	18,351,639	18,487,913	18,490,150
Retirements	-	-	-	-	-	-	-	-	-	-	-	(462,853,037)
Book Removals	(325,057)	(5,167)	(1,466,396)	(12,057)	(112,629)	(222,599)	(185,649)	(35,342)	(158,551)	(67,938)	(117,872)	(1,295,995)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	(2,739)	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	3	0	49	12	5	82	13	2	6	21	21	(38)
Electric Other Production Plant	1,385,555,086	1,403,677,620	1,420,335,362	1,438,454,778	1,456,488,616	1,474,448,131	1,492,476,190	1,510,664,116	1,528,746,820	1,547,030,542	1,565,400,604	1,119,741,685
Electric Other Production Plant RWIP	20,279,424	20,411,340	19,225,987	19,360,117	24,197,943	28,870,766	33,572,714	33,812,798	34,221,898	34,601,286	34,646,236	33,830,701
Total Electric Other Production including RWIP	1,365,275,662	1,383,266,280	1,401,109,375	1,419,094,661	1,432,290,673	1,445,577,365	1,458,903,476	1,476,851,318	1,494,524,922	1,512,429,256	1,530,754,368	1,085,910,984
Electric Transmission Plant												
Accumulated Depreciation Beginning Balance	1,080,943,236	1,086,781,457	1,091,623,867	1,090,782,300	1,096,763,638	1,102,517,479	1,108,092,403	1,114,150,209	1,120,054,021	1,125,726,488	1,131,827,686	1,137,898,421
Book Depreciation	7,047,820	7,055,597	7,076,166	7,090,871	7,105,879	7,144,524	7,169,806	7,174,838	7,193,004	7,210,581	7,216,038	7,316,640
Retirements	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)	(1,109,317)
Book Removals	(100,264)	(1,107,406)	(6,728,927)	(200)	(242,704)	(460,266)	(2,666)	(161,693)	(411,203)	(50)	(35,971)	(468,535)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	3,554	(79,465)	-	-	-	-	-	-	-	-	(983)
Transfers & Adjustments	(18)	(18)	(24)	(17)	(17)	(17)	(17)	(17)	(17)	(16)	(16)	(16)
Electric Transmission Plant	1,086,781,457	1,091,623,867	1,090,782,300	1,096,763,638	1,102,517,479	1,108,092,403	1,114,150,209	1,120,054,021	1,125,726,488	1,131,827,686	1,137,898,421	1,143,636,209
Electric Transmission Plant RWIP	9,086,132	8,260,234	1,837,589	2,125,870	2,177,310	2,065,352	2,373,992	2,446,109	2,504,124	2,866,944	3,231,161	3,253,938
Total Electric Transmission including RWIP	1,077,695,326	1,083,363,633	1,088,944,710	1,094,637,768	1,100,340,169	1,106,027,051	1,111,776,218	1,117,607,912	1,123,222,365	1,128,960,743	1,134,667,260	1,140,382,272

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant (1)												
Accumulated Depreciation Beginning Balance	1,804,611,935	1,810,851,794	1,817,298,316	1,822,858,905	1,829,746,780	1,836,746,834	1,843,923,884	1,851,168,329	1,858,531,417	1,865,930,944	1,873,613,269	1,881,483,023
Book Depreciation	11,369,773	11,492,089	11,612,538	11,734,403	11,861,571	11,998,089	12,140,361	12,281,909	12,426,474	12,588,180	12,776,286	12,943,248
Retirements	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)	(3,294,178)
Book Removals	(1,852,840)	(1,760,184)	(3,173,286)	(1,554,749)	(1,568,618)	(1,527,538)	(1,602,092)	(1,624,827)	(1,732,862)	(1,611,722)	(1,612,375)	(1,653,099)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	17,104	8,795	415,514	2,400	1,278	677	355	183	92	45	21	9
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant	1,810,851,794	1,817,298,316	1,822,858,905	1,829,746,780	1,836,746,834	1,843,923,884	1,851,168,329	1,858,531,417	1,865,930,944	1,873,613,269	1,881,483,023	1,889,479,003
Electric Distribution Plant RWIP	5,058,491	5,050,571	4,044,742	4,309,463	4,587,545	4,966,748	5,347,863	5,685,773	5,842,170	5,923,039	5,928,230	6,039,157
Total Electric Distribution including RWIP	1,805,793,303	1,812,247,745	1,818,814,162	1,825,437,317	1,832,159,289	1,838,957,135	1,845,820,466	1,852,845,644	1,860,088,774	1,867,690,230	1,875,554,792	1,883,439,846
Electric General Plant												
Accumulated Depreciation Beginning Balance	356,012,606	360,488,844	364,986,662	369,308,183	373,920,882	378,569,954	383,252,325	387,940,535	392,637,123	397,085,492	401,789,926	406,484,262
Book Depreciation	4,477,163	4,491,203	4,530,624	4,597,491	4,632,966	4,696,838	4,754,127	4,794,502	4,810,874	4,795,552	4,751,355	4,835,627
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(16,776)	(15,423)	(240,181)	(12,104)	(12,142)	(38,236)	(81,050)	(77,274)	(243,476)	(13,052)	(37,424)	(167,482)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	5	3	8	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	15,847	22,036	31,070	27,312	28,248	23,769	15,133	(20,641)	(119,028)	(78,066)	(19,595)	15,145
Electric General Plant	360,488,844	364,986,662	369,308,183	373,920,882	378,569,954	383,252,325	387,940,535	392,637,123	397,085,492	401,789,926	406,484,262	411,167,553
Electric General Plant RWIP	781,978	808,390	614,633	670,826	743,239	788,164	802,113	819,804	669,721	854,272	926,648	864,416
Total Electric General including RWIP	359,706,866	364,178,272	368,693,550	373,250,056	377,826,715	382,464,161	387,138,422	391,817,319	396,415,771	400,935,654	405,557,614	410,303,137
Total Electric Utility	8,922,560,524	8,981,722,372	9,033,210,279	9,094,719,423	9,153,873,409	9,215,125,101	9,277,076,506	9,339,600,920	9,401,532,052	9,465,233,719	9,529,221,243	8,899,549,401
Total Electric Utility RWIP	38,968,021	38,588,571	30,217,420	33,410,664	37,380,129	42,917,697	48,826,295	50,823,411	55,348,445	57,053,545	57,782,797	54,901,361
Total Electric Utility including RWIP	8,883,592,503	8,943,133,801	9,002,992,859	9,061,308,759	9,116,493,280	9,172,207,404	9,228,250,211	9,288,777,508	9,346,183,607	9,408,180,174	9,471,438,446	8,844,648,040
Common Intangible Plant												
Accumulated Depreciation Beginning Balance	333,939,964	339,414,783	344,906,079	350,367,365	355,782,378	361,172,810	366,528,771	371,863,925	377,106,111	382,224,957	387,310,908	392,430,160
Book Depreciation	5,477,135	5,488,973	5,456,849	5,414,036	5,397,939	5,355,896	5,335,106	5,235,235	5,102,490	5,094,486	5,124,353	6,587,168
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(2,316)	2,324	4,437	977	(7,507)	65	49	6,950	16,356	(8,534)	(5,102)	(1,118)
Common Intangible Plant	339,414,783	344,906,079	350,367,365	355,782,378	361,172,810	366,528,771	371,863,925	377,106,111	382,224,957	387,310,908	392,430,160	399,016,210
Common Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Common Intangible including RWIP	339,414,783	344,906,079	350,367,365	355,782,378	361,172,810	366,528,771	371,863,925	377,106,111	382,224,957	387,310,908	392,430,160	399,016,210
Common General Plant												
Accumulated Depreciation Beginning Balance	156,056,357	159,727,309	163,293,016	166,162,580	169,844,480	173,528,924	177,162,805	180,830,700	184,504,897	188,017,633	191,685,386	194,958,892
Book Depreciation	3,615,377	3,608,374	3,636,720	3,676,044	3,633,342	3,673,890	3,697,213	3,671,479	3,777,842	3,791,996	3,679,065	3,839,423
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(12,418)	(97,666)	(776,964)	(5,992)	(4,730)	(3,749)	(2,997)	(2,411)	(138,153)	(30,087)	(436,935)	(1,089)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	1,840	1,380	1,035	776	582	437	327	246	184	138	104	78
Transfers & Adjustments	66,154	53,619	8,773	11,072	55,250	(36,697)	(26,648)	4,883	(127,137)	(94,294)	31,273	29,501
Common General Plant	159,727,309	163,293,016	166,162,580	169,844,480	173,528,924	177,162,805	180,830,700	184,504,897	188,017,633	191,685,386	194,958,892	198,826,805
Common General Plant RWIP	1,795,874	1,700,319	957,158	994,780	1,111,474	1,240,229	1,371,329	1,501,855	1,484,763	1,556,912	1,222,138	1,320,222
Total Common General including RWIP	157,931,435	161,592,697	165,205,421	168,849,700	172,417,451	175,922,576	179,459,372	183,003,042	186,532,870	190,128,475	193,736,754	197,506,583
Total Common Utility	499,142,092	508,199,095	516,529,944	525,626,858	534,701,734	543,691,576	552,694,626	561,611,008	570,242,590	578,996,295	587,389,052	597,843,015
Total Common Utility RWIP	1,795,874	1,700,319	957,158	994,780	1,111,474	1,240,229	1,371,329	1,501,855	1,484,763	1,556,912	1,222,138	1,320,222
Total Common Utility including RWIP	497,346,217	506,498,776	515,572,786	524,632,078	533,590,260	542,451,347	551,323,297	560,109,153	568,757,827	577,439,383	586,166,914	596,522,793

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Nuclear Fuel												
Accumulated Depreciation Beginning Balance	2,772,531,416	2,782,927,679	2,792,343,358	2,802,739,621	2,812,809,022	2,823,205,285	2,833,274,686	2,843,670,949	2,854,067,212	2,864,127,184	2,872,547,032	2,881,685,670
Book Depreciation	10,396,263	9,415,679	10,396,263	10,069,401	10,396,263	10,069,401	10,396,263	10,396,263	10,059,972	8,419,848	9,138,638	10,345,605
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	2,782,927,679	2,792,343,358	2,802,739,621	2,812,809,022	2,823,205,285	2,833,274,686	2,843,670,949	2,854,067,212	2,864,127,184	2,872,547,032	2,881,685,670	2,892,031,275
Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	2,782,927,679	2,792,343,358	2,802,739,621	2,812,809,022	2,823,205,285	2,833,274,686	2,843,670,949	2,854,067,212	2,864,127,184	2,872,547,032	2,881,685,670	2,892,031,275
Total Nuclear Fuel	2,782,927,679	2,792,343,358	2,802,739,621	2,812,809,022	2,823,205,285	2,833,274,686	2,843,670,949	2,854,067,212	2,864,127,184	2,872,547,032	2,881,685,670	2,892,031,275
Total Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	2,782,927,679	2,792,343,358	2,802,739,621	2,812,809,022	2,823,205,285	2,833,274,686	2,843,670,949	2,854,067,212	2,864,127,184	2,872,547,032	2,881,685,670	2,892,031,275
Decommissioning												
Accumulated Depreciation Beginning Balance	1,835,556,871	1,838,370,149	1,841,183,427	1,843,996,705	1,846,809,983	1,849,623,261	1,852,436,539	1,855,249,817	1,858,063,095	1,860,876,373	1,863,689,651	1,866,502,929
Book Depreciation	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Decommissioning	1,838,370,149	1,841,183,427	1,843,996,705	1,846,809,983	1,849,623,261	1,852,436,539	1,855,249,817	1,858,063,095	1,860,876,373	1,863,689,651	1,866,502,929	1,869,316,207
Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,838,370,149	1,841,183,427	1,843,996,705	1,846,809,983	1,849,623,261	1,852,436,539	1,855,249,817	1,858,063,095	1,860,876,373	1,863,689,651	1,866,502,929	1,869,316,207
Total Decommissioning	1,838,370,149	1,841,183,427	1,843,996,705	1,846,809,983	1,849,623,261	1,852,436,539	1,855,249,817	1,858,063,095	1,860,876,373	1,863,689,651	1,866,502,929	1,869,316,207
Total Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,838,370,149	1,841,183,427	1,843,996,705	1,846,809,983	1,849,623,261	1,852,436,539	1,855,249,817	1,858,063,095	1,860,876,373	1,863,689,651	1,866,502,929	1,869,316,207
NSPM Theoretical Reserve - Distribution												
Accumulated Depreciation Beginning Balance	(81,287,811)	(80,892,432)	(80,497,054)	(80,101,675)	(79,706,296)	(79,310,918)	(78,915,539)	(78,520,161)	(78,124,782)	(77,729,404)	(77,334,025)	(76,938,647)
Book Depreciation	395,379	395,379	395,379	395,379	395,379	395,379	395,379	395,379	395,379	395,379	395,379	395,379
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(80,892,432)	(80,497,054)	(80,101,675)	(79,706,296)	(79,310,918)	(78,915,539)	(78,520,161)	(78,124,782)	(77,729,404)	(77,334,025)	(76,938,647)	(76,543,268)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(80,892,432)	(80,497,054)	(80,101,675)	(79,706,296)	(79,310,918)	(78,915,539)	(78,520,161)	(78,124,782)	(77,729,404)	(77,334,025)	(76,938,647)	(76,543,268)
NSPM Theoretical Reserve - Transmission												
Accumulated Depreciation Beginning Balance	(131,894,499)	(131,599,450)	(131,304,402)	(131,009,354)	(130,714,305)	(130,419,257)	(130,124,209)	(129,829,160)	(129,534,112)	(129,239,064)	(128,944,015)	(128,648,967)
Book Depreciation	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(131,599,450)	(131,304,402)	(131,009,354)	(130,714,305)	(130,419,257)	(130,124,209)	(129,829,160)	(129,534,112)	(129,239,064)	(128,944,015)	(128,648,967)	(128,353,919)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(131,599,450)	(131,304,402)	(131,009,354)	(130,714,305)	(130,419,257)	(130,124,209)	(129,829,160)	(129,534,112)	(129,239,064)	(128,944,015)	(128,648,967)	(128,353,919)

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
NSPM Theoretical Reserve - General and Intangible												
Accumulated Depreciation Beginning Balance	(1,024,369)	(1,009,966)	(995,562)	(981,159)	(966,756)	(952,353)	(937,950)	(923,546)	(909,143)	(894,740)	(880,337)	(865,934)
Book Depreciation	14,403	14,403	14,403	14,403	14,403	14,403	14,403	14,403	14,403	14,403	14,403	14,403
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(1,009,966)	(995,562)	(981,159)	(966,756)	(952,353)	(937,950)	(923,546)	(909,143)	(894,740)	(880,337)	(865,934)	(851,530)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(1,009,966)	(995,562)	(981,159)	(966,756)	(952,353)	(937,950)	(923,546)	(909,143)	(894,740)	(880,337)	(865,934)	(851,530)
Total NSPM Theoretical Reserve	(213,501,848)	(212,797,018)	(212,092,188)	(211,387,358)	(210,682,528)	(209,977,698)	(209,272,868)	(208,568,037)	(207,863,207)	(207,158,377)	(206,453,547)	(205,748,717)
Total NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(213,501,848)	(212,797,018)	(212,092,188)	(211,387,358)	(210,682,528)	(209,977,698)	(209,272,868)	(208,568,037)	(207,863,207)	(207,158,377)	(206,453,547)	(205,748,717)
Sherco Reg Asset												
Accumulated Depreciation Beginning Balance	(6,540,686)	(6,498,759)	(6,456,831)	(6,414,904)	(6,372,976)	(6,331,049)	(6,289,121)	(6,247,194)	(6,205,266)	(6,163,339)	(6,121,411)	(6,079,484)
Book Depreciation	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Sherco Reg Asset	(6,498,759)	(6,456,831)	(6,414,904)	(6,372,976)	(6,331,049)	(6,289,121)	(6,247,194)	(6,205,266)	(6,163,339)	(6,121,411)	(6,079,484)	(6,037,556)
Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(6,498,759)	(6,456,831)	(6,414,904)	(6,372,976)	(6,331,049)	(6,289,121)	(6,247,194)	(6,205,266)	(6,163,339)	(6,121,411)	(6,079,484)	(6,037,556)
Total Sherco Reg Asset Reserve	(6,498,759)	(6,456,831)	(6,414,904)	(6,372,976)	(6,331,049)	(6,289,121)	(6,247,194)	(6,205,266)	(6,163,339)	(6,121,411)	(6,079,484)	(6,037,556)
Total Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(6,498,759)	(6,456,831)	(6,414,904)	(6,372,976)	(6,331,049)	(6,289,121)	(6,247,194)	(6,205,266)	(6,163,339)	(6,121,411)	(6,079,484)	(6,037,556)
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets	13,822,999,837	13,904,194,403	13,977,969,457	14,062,204,951	14,144,390,112	14,228,261,082	14,313,171,836	14,398,568,931	14,482,751,652	14,567,186,907	14,652,265,862	14,046,953,624
Removal Work in Process (RWIP)	40,763,896	40,288,890	31,174,578	34,405,443	38,491,603	44,157,926	50,197,624	52,325,267	56,833,208	58,610,457	59,004,935	56,221,583
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets including RWIP	13,782,235,941	13,863,905,513	13,946,794,879	14,027,799,508	14,105,898,509	14,184,103,157	14,262,974,212	14,346,243,664	14,425,918,445	14,508,576,451	14,593,260,928	13,990,732,041

Footnotes:

(1) Electric Distribution Plant in the schedule above contains NSPM total company a

	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
Accumulated Depreciation Beginning Balance	1,528,458,262	1,534,274,661	1,540,473,063	1,545,727,737	1,552,165,783	1,558,691,082	1,565,378,589	1,572,132,164	1,578,987,662	1,585,869,818	1,593,026,732	1,600,351,492
Book Depreciation	10,370,018	10,477,609	10,580,718	10,692,129	10,808,971	10,935,281	11,066,917	11,197,932	11,332,212	11,483,398	11,661,119	11,816,505
Retirements	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)	(2,907,668)
Book Removals	(1,662,754)	(1,380,275)	(2,833,931)	(1,348,890)	(1,377,360)	(1,340,850)	(1,406,084)	(1,434,992)	(1,542,512)	(1,418,886)	(1,428,729)	(1,466,432)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	16,803	8,736	415,556	2,475	1,356	745	410	226	125	69	38	21
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant - MN	1,534,274,661	1,540,473,063	1,545,727,737	1,552,165,783	1,558,691,082	1,565,378,589	1,572,132,164	1,578,987,662	1,585,869,818	1,593,026,732	1,600,351,492	1,607,793,918
Electric Distribution Plant - MN RWIP	4,233,932	4,391,635	3,509,923	3,750,563	3,985,802	4,309,060	4,629,246	4,907,944	5,015,220	5,073,284	5,077,508	5,177,642
Total Electric Distribution - MN including RWIP	1,530,040,728	1,536,081,428	1,542,217,814	1,548,415,220	1,554,705,280	1,561,069,529	1,567,502,918	1,574,079,718	1,580,854,598	1,587,953,448	1,595,273,984	1,602,616,276

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Accumulated Depreciation Beginning Balance	282,342,574	285,242,148	288,190,783	291,249,952	294,013,520	296,780,288	299,564,576	302,351,888	305,123,326	307,848,131	310,521,298	313,205,760
Book Depreciation	2,910,872	2,959,932	2,865,151	2,737,172	2,816,706	2,830,142	2,827,552	2,795,134	2,698,673	2,701,081	2,703,969	2,955,333
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	(15,100)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(11,299)	(11,297)	194,018	26,396	(49,937)	(45,854)	(40,240)	(23,696)	26,132	(27,914)	(19,507)	(17,530)
Electric Intangible Plant	285,242,148	288,190,783	291,249,952	294,013,520	296,780,288	299,564,576	302,351,888	305,123,326	307,848,131	310,521,298	313,205,760	316,128,463
Electric Intangible Plant RWIP	15,000	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	-
Total Electric Intangible including RWIP	285,227,148	288,175,683	291,234,852	293,998,420	296,765,188	299,549,476	302,336,788	305,108,226	307,833,031	310,506,198	313,190,660	316,128,463
Electric Steam Production Plant												
Accumulated Depreciation Beginning Balance	1,634,026,814	1,641,694,354	1,640,540,087	1,648,473,918	1,656,363,703	1,664,162,543	1,671,892,834	1,679,869,930	1,687,812,528	1,695,865,306	1,703,976,008	1,712,000,710
Book Depreciation	7,876,213	7,894,791	7,935,514	7,968,311	7,996,247	8,026,008	8,036,333	8,043,402	8,067,570	8,140,611	8,211,772	8,244,972
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(209,456)	(9,044,727)	(2,817)	(79,555)	(198,308)	(296,462)	(59,865)	(101,445)	(15,523)	(31,084)	(188,051)	(548,126)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	35	34	50	81	307	61	58	111	100	359	215	797,654
Transfers & Adjustments	748	(4,365)	1,085	948	594	683	570	531	633	816	766	609
Electric Steam Production Plant	1,641,694,354	1,640,540,087	1,648,473,918	1,656,363,703	1,664,162,543	1,671,892,834	1,679,869,930	1,687,812,528	1,695,865,306	1,703,976,008	1,712,000,710	1,720,495,820
Electric Steam Production Plant RWIP	9,811,772	1,126,975	1,420,101	1,426,824	1,356,335	1,139,388	1,152,077	1,254,746	1,387,476	1,455,903	1,574,721	1,896,494
Total Electric Steam Production including RWIP	1,631,882,582	1,639,413,112	1,647,053,817	1,654,936,879	1,662,806,208	1,670,753,446	1,678,717,852	1,686,557,781	1,694,477,830	1,702,520,105	1,710,425,989	1,718,599,326
Electric Nuclear Production Plant												
Accumulated Depreciation Beginning Balance	2,400,072,531	2,414,940,478	2,429,471,355	2,444,417,101	2,459,463,992	2,474,753,304	2,490,264,142	2,505,199,393	2,519,653,865	2,534,430,478	2,550,127,242	2,565,957,753
Book Depreciation	14,867,945	14,869,956	14,945,744	15,056,889	15,289,311	15,510,836	15,602,367	15,690,180	15,723,691	15,769,138	15,830,509	16,044,231
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	(339,080)	-	(10,000)	-	-	(667,117)	(1,235,709)	(947,080)	(72,375)	-	(915,000)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	2	2	2	2	2	2	2	2	2	2	2	2
Electric Nuclear Production Plant	2,414,940,478	2,429,471,355	2,444,417,101	2,459,463,992	2,474,753,304	2,490,264,142	2,505,199,393	2,519,653,865	2,534,430,478	2,550,127,242	2,565,957,753	2,581,086,985
Electric Nuclear Production Plant RWIP	1,990,583	1,771,503	1,821,503	2,758,850	2,937,750	2,962,814	2,295,696	1,114,987	530,283	1,124,643	1,124,643	209,643
Total Electric Nuclear Production including RWIP	2,412,949,895	2,427,699,853	2,442,595,598	2,456,705,142	2,471,815,555	2,487,301,328	2,502,903,696	2,518,538,878	2,533,900,195	2,549,002,599	2,564,833,110	2,580,877,342
Electric Hydro Production Plant												
Accumulated Depreciation Beginning Balance	19,083,032	19,205,904	19,328,777	19,451,650	19,574,522	19,697,394	19,820,267	19,943,140	20,066,012	20,188,885	20,311,757	20,434,630
Book Depreciation	122,873	122,873	122,873	122,873	122,873	122,873	122,873	122,873	122,873	122,873	122,874	122,874
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Electric Hydro Production Plant	19,205,904	19,328,777	19,451,650	19,574,522	19,697,394	19,820,267	19,943,140	20,066,012	20,188,885	20,311,757	20,434,630	20,557,503
Electric Hydro Production Plant RWIP	1,318	1,318	1,318	1,317	1,316	1,316	1,316	1,316	1,315	1,314	1,313	1,313
Total Electric Hydro Production including RWIP	19,204,586	19,327,459	19,450,332	19,573,205	19,696,078	19,818,951	19,941,824	20,064,697	20,187,570	20,310,443	20,433,317	20,556,190
Electric Other Production Plant												
Accumulated Depreciation Beginning Balance	1,119,741,685	1,138,807,618	1,158,070,079	1,177,361,127	1,196,705,484	1,216,089,056	1,210,018,925	1,228,929,213	1,248,332,411	1,267,798,757	1,287,521,395	1,117,910,786
Book Depreciation	19,272,874	19,277,484	19,298,978	19,357,161	19,441,323	19,491,255	19,480,695	19,486,668	19,492,467	19,836,029	20,001,207	20,280,545
Retirements	-	-	-	-	-	(24,658,386)	-	-	-	-	(189,493,688)	-
Book Removals	(206,947)	(15,023)	(7,929)	(13,726)	(57,794)	(903,311)	(570,429)	(83,482)	(26,113)	(113,398)	(118,170)	(528,087)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	6	(1)	(1)	923	43	311	22	11	(8)	7	42	5
Electric Other Production Plant	1,138,807,618	1,158,070,079	1,177,361,127	1,196,705,484	1,216,089,056	1,210,018,925	1,228,929,213	1,248,332,411	1,267,798,757	1,287,521,395	1,117,910,786	1,137,663,249
Electric Other Production Plant RWIP	33,688,528	34,029,812	34,789,469	35,388,594	38,318,547	40,395,984	42,823,301	43,329,092	44,278,951	44,775,525	45,314,024	45,529,572
Total Electric Other Production including RWIP	1,105,119,090	1,124,040,267	1,142,571,658	1,161,316,890	1,177,770,509	1,169,622,942	1,186,105,912	1,205,003,319	1,223,519,806	1,242,745,871	1,072,596,763	1,092,133,677
Electric Transmission Plant												
Accumulated Depreciation Beginning Balance	1,143,636,209	1,149,814,000	1,155,976,365	1,160,127,630	1,166,423,366	1,172,662,731	1,178,490,932	1,184,943,738	1,191,369,669	1,197,012,362	1,203,435,315	1,209,958,237
Book Depreciation	7,420,657	7,433,488	7,476,157	7,512,341	7,518,725	7,569,549	7,620,364	7,625,914	7,656,465	7,687,831	7,690,481	7,774,516
Retirements	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)	(1,167,539)
Book Removals	(75,312)	(103,567)	(2,157,336)	(49,050)	(111,804)	(573,792)	(4)	(32,428)	(846,217)	(97,324)	(4)	(715,705)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(16)	(16)	(18)	(16)	(16)	(16)	(15)	(15)	(16)	(15)	(15)	(15)
Electric Transmission Plant	1,149,814,000	1,155,976,365	1,160,127,630	1,166,423,366	1,172,662,731	1,178,490,932	1,184,943,738	1,191,369,669	1,197,012,362	1,203,435,315	1,209,958,237	1,215,849,493
Electric Transmission Plant RWIP	3,398,601	3,441,899	1,755,149	1,878,510	1,969,428	1,904,526	2,130,404	2,290,213	1,985,819	2,178,360	2,457,983	2,189,806
Total Electric Transmission including RWIP	1,146,415,399	1,152,534,466	1,158,372,481	1,164,544,856	1,170,693,303	1,176,586,406	1,182,813,334	1,189,079,456	1,195,026,542	1,201,256,954	1,207,500,254	1,213,659,687

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant (1)												
Accumulated Depreciation Beginning Balance	1,889,479,003	1,896,724,289	1,904,971,419	1,912,471,573	1,920,994,120	1,929,683,938	1,938,536,053	1,947,401,930	1,956,474,293	1,964,561,487	1,973,840,327	1,983,122,283
Book Depreciation	13,115,744	13,265,792	13,410,539	13,560,660	13,708,681	13,871,660	14,036,639	14,188,580	14,341,330	14,511,564	14,672,143	14,811,183
Retirements	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)	(3,344,770)
Book Removals	(2,528,460)	(1,673,893)	(2,565,613)	(1,693,343)	(1,674,092)	(1,674,774)	(1,825,991)	(1,771,446)	(2,909,366)	(1,887,954)	(2,045,417)	(1,637,664)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	2,772	0	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant	1,896,724,289	1,904,971,419	1,912,471,573	1,920,994,120	1,929,683,938	1,938,536,053	1,947,401,930	1,956,474,293	1,964,561,487	1,973,840,327	1,983,122,283	1,992,951,032
Electric Distribution Plant RWIP	5,451,858	5,696,626	5,070,007	5,371,385	5,729,916	6,129,266	6,427,857	6,761,249	5,908,320	5,912,270	5,463,153	5,561,574
Total Electric Distribution including RWIP	1,891,272,431	1,899,274,793	1,907,401,566	1,915,622,735	1,923,954,021	1,932,406,787	1,940,974,073	1,949,713,045	1,958,653,167	1,967,928,056	1,977,659,129	1,987,389,458
Electric General Plant												
Accumulated Depreciation Beginning Balance	411,167,553	416,099,849	420,907,294	425,593,201	430,738,595	436,005,568	441,213,607	446,579,873	451,925,106	457,181,682	462,610,017	468,053,216
Book Depreciation	4,987,029	4,976,887	4,994,978	5,160,610	5,293,955	5,339,693	5,398,960	5,394,339	5,403,798	5,437,141	5,442,736	5,592,848
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(35,734)	(152,423)	(304,775)	(13,770)	(15,494)	(120,636)	(17,482)	(16,429)	(142,868)	(15,340)	(15,122)	(196,094)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(18,998)	(17,020)	(4,296)	(1,446)	(11,487)	(11,018)	(15,212)	(32,677)	(4,354)	6,534	15,585	16,679
Electric General Plant	416,099,849	420,907,294	425,593,201	430,738,595	436,005,568	441,213,607	446,579,873	451,925,106	457,181,682	462,610,017	468,053,216	473,466,649
Electric General Plant RWIP	912,916	868,695	681,478	777,152	942,276	1,069,701	1,323,040	1,664,864	1,694,559	1,855,331	2,011,983	1,955,539
Total Electric General including RWIP	415,186,933	420,038,599	424,911,723	429,961,443	435,063,292	440,143,906	445,256,833	450,260,242	455,487,123	460,754,686	466,041,233	471,511,110
Total Electric Utility	8,962,528,640	9,017,456,158	9,079,146,152	9,144,277,301	9,209,834,822	9,249,801,336	9,315,219,104	9,380,757,210	9,444,887,088	9,512,343,359	9,390,643,376	9,458,199,193
Total Electric Utility RWIP	55,270,576	46,951,927	45,554,124	47,617,732	51,270,668	53,618,094	56,168,792	56,431,568	55,801,823	57,318,446	57,962,921	57,343,940
Total Electric Utility including RWIP	8,907,258,065	8,970,504,231	9,033,592,027	9,096,659,570	9,158,564,154	9,196,183,241	9,259,050,311	9,324,325,642	9,389,085,264	9,455,024,912	9,332,680,455	9,400,855,253
Common Intangible Plant												
Accumulated Depreciation Beginning Balance	399,016,210	405,600,977	412,296,676	419,018,764	425,614,918	431,990,761	438,373,914	444,737,102	451,036,313	457,223,204	463,312,987	469,382,482
Book Depreciation	6,591,907	6,696,552	6,717,802	6,591,073	6,379,638	6,378,853	6,367,130	6,260,867	6,200,446	6,106,951	6,083,251	6,861,174
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(7,140)	(852)	4,286	5,081	(3,794)	4,300	(3,942)	38,344	(13,555)	(17,169)	(13,755)	903
Common Intangible Plant	405,600,977	412,296,676	419,018,764	425,614,918	431,990,761	438,373,914	444,737,102	451,036,313	457,223,204	463,312,987	469,382,482	476,244,560
Common Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Common Intangible including RWIP	405,600,977	412,296,676	419,018,764	425,614,918	431,990,761	438,373,914	444,737,102	451,036,313	457,223,204	463,312,987	469,382,482	476,244,560
Common General Plant												
Accumulated Depreciation Beginning Balance	198,826,805	202,671,511	206,490,857	209,265,530	213,233,837	217,214,906	221,256,886	225,353,396	229,415,367	233,728,853	238,294,625	242,918,308
Book Depreciation	3,998,848	3,999,319	3,939,809	3,943,354	3,949,025	4,007,658	4,068,132	4,077,440	4,326,426	4,553,879	4,551,975	4,693,573
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(105,805)	(72,683)	(1,145,215)	(589)	(525)	(475)	(446)	(423)	(404)	(377)	(357)	(353)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	58	44	33	25	18	14	10	8	6	4	3	2
Transfers & Adjustments	(48,394)	(107,334)	(19,955)	25,517	32,550	34,782	28,813	(15,054)	(12,542)	12,266	72,062	51,363
Common General Plant	202,671,511	206,490,857	209,265,530	213,233,837	217,214,906	221,256,886	225,353,396	229,415,367	233,728,853	238,294,625	242,918,308	247,662,893
Common General Plant RWIP	1,215,063	1,143,261	6,368	21,359	73,790	139,614	237,670	344,447	451,021	554,487	646,325	733,270
Total Common General including RWIP	201,456,449	205,347,595	209,259,162	213,212,478	217,141,115	221,117,271	225,115,726	229,070,920	233,277,832	237,740,138	242,271,983	246,929,623
Total Common Utility	608,272,488	618,787,533	628,284,293	638,848,755	649,205,667	659,630,799	670,090,498	680,451,680	690,952,057	701,607,612	712,300,790	723,907,453
Total Common Utility RWIP	1,215,063	1,143,261	6,368	21,359	73,790	139,614	237,670	344,447	451,021	554,487	646,325	733,270
Total Common Utility including RWIP	607,057,425	617,644,272	628,277,926	638,827,396	649,131,877	659,491,185	669,852,828	680,107,233	690,501,036	701,053,125	711,654,466	723,174,183

Functional Class	2023 January	February	March	April	May	June	July	August	September	October	November	December
Nuclear Fuel												
Accumulated Depreciation Beginning Balance	2,892,031,275	2,902,393,690	2,911,780,423	2,922,011,006	2,930,186,213	2,939,600,516	2,949,708,153	2,960,143,367	2,970,578,581	2,980,533,380	2,987,845,078	2,997,889,682
Book Depreciation	10,362,415	9,386,733	10,230,583	8,175,207	9,414,303	10,107,637	10,435,214	10,435,214	9,954,799	7,311,698	10,044,604	10,370,079
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	2,902,393,690	2,911,780,423	2,922,011,006	2,930,186,213	2,939,600,516	2,949,708,153	2,960,143,367	2,970,578,581	2,980,533,380	2,987,845,078	2,997,889,682	3,008,259,761
Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	2,902,393,690	2,911,780,423	2,922,011,006	2,930,186,213	2,939,600,516	2,949,708,153	2,960,143,367	2,970,578,581	2,980,533,380	2,987,845,078	2,997,889,682	3,008,259,761
Total Nuclear Fuel	2,902,393,690	2,911,780,423	2,922,011,006	2,930,186,213	2,939,600,516	2,949,708,153	2,960,143,367	2,970,578,581	2,980,533,380	2,987,845,078	2,997,889,682	3,008,259,761
Total Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	2,902,393,690	2,911,780,423	2,922,011,006	2,930,186,213	2,939,600,516	2,949,708,153	2,960,143,367	2,970,578,581	2,980,533,380	2,987,845,078	2,997,889,682	3,008,259,761
Decommissioning												
Accumulated Depreciation Beginning Balance	1,869,316,207	1,872,129,485	1,874,942,763	1,877,756,041	1,880,569,319	1,883,382,597	1,886,195,875	1,889,009,153	1,891,822,431	1,894,635,709	1,897,448,987	1,900,262,265
Book Depreciation	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Decommissioning	1,872,129,485	1,874,942,763	1,877,756,041	1,880,569,319	1,883,382,597	1,886,195,875	1,889,009,153	1,891,822,431	1,894,635,709	1,897,448,987	1,900,262,265	1,903,075,543
Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,872,129,485	1,874,942,763	1,877,756,041	1,880,569,319	1,883,382,597	1,886,195,875	1,889,009,153	1,891,822,431	1,894,635,709	1,897,448,987	1,900,262,265	1,903,075,543
Total Decommissioning	1,872,129,485	1,874,942,763	1,877,756,041	1,880,569,319	1,883,382,597	1,886,195,875	1,889,009,153	1,891,822,431	1,894,635,709	1,897,448,987	1,900,262,265	1,903,075,543
Total Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,872,129,485	1,874,942,763	1,877,756,041	1,880,569,319	1,883,382,597	1,886,195,875	1,889,009,153	1,891,822,431	1,894,635,709	1,897,448,987	1,900,262,265	1,903,075,543
NSPM Theoretical Reserve - Distribution												
Accumulated Depreciation Beginning Balance	(76,543,268)	(76,157,204)	(75,771,139)	(75,385,075)	(74,999,010)	(74,612,946)	(74,226,882)	(73,840,817)	(73,454,753)	(73,068,688)	(72,682,624)	(72,296,560)
Book Depreciation	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(76,157,204)	(75,771,139)	(75,385,075)	(74,999,010)	(74,612,946)	(74,226,882)	(73,840,817)	(73,454,753)	(73,068,688)	(72,682,624)	(72,296,560)	(71,910,495)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(76,157,204)	(75,771,139)	(75,385,075)	(74,999,010)	(74,612,946)	(74,226,882)	(73,840,817)	(73,454,753)	(73,068,688)	(72,682,624)	(72,296,560)	(71,910,495)
NSPM Theoretical Reserve - Transmission												
Accumulated Depreciation Beginning Balance	(128,353,919)	(128,058,870)	(127,763,822)	(127,468,774)	(127,173,725)	(126,878,677)	(126,583,629)	(126,288,581)	(125,993,532)	(125,698,484)	(125,403,436)	(125,108,387)
Book Depreciation	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(128,058,870)	(127,763,822)	(127,468,774)	(127,173,725)	(126,878,677)	(126,583,629)	(126,288,581)	(125,993,532)	(125,698,484)	(125,403,436)	(125,108,387)	(124,813,339)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(128,058,870)	(127,763,822)	(127,468,774)	(127,173,725)	(126,878,677)	(126,583,629)	(126,288,581)	(125,993,532)	(125,698,484)	(125,403,436)	(125,108,387)	(124,813,339)

Northern States Power Company
Roll Forward by Functional Class
Depreciation Reserve

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 28 of 36

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
NSPM Theoretical Reserve - General and Intangible												
Accumulated Depreciation Beginning Balance	(851,530)	(842,856)	(834,182)	(825,508)	(816,834)	(808,160)	(799,486)	(790,812)	(782,137)	(773,463)	(764,789)	(756,115)
Book Depreciation	8,674	8,674	8,674	8,674	8,674	8,674	8,674	8,674	8,674	8,674	8,674	8,674
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(842,856)	(834,182)	(825,508)	(816,834)	(808,160)	(799,486)	(790,812)	(782,137)	(773,463)	(764,789)	(756,115)	(747,441)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(842,856)	(834,182)	(825,508)	(816,834)	(808,160)	(799,486)	(790,812)	(782,137)	(773,463)	(764,789)	(756,115)	(747,441)
Total NSPM Theoretical Reserve	(205,058,930)	(204,369,143)	(203,679,357)	(202,989,570)	(202,299,783)	(201,609,996)	(200,920,209)	(200,230,422)	(199,540,636)	(198,850,849)	(198,161,062)	(197,471,275)
Total NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(205,058,930)	(204,369,143)	(203,679,357)	(202,989,570)	(202,299,783)	(201,609,996)	(200,920,209)	(200,230,422)	(199,540,636)	(198,850,849)	(198,161,062)	(197,471,275)
Sherco Reg Asset												
Accumulated Depreciation Beginning Balance	(6,037,556)	(5,995,629)	(5,953,701)	(5,911,774)	(5,869,847)	(5,827,919)	(5,785,992)	(5,744,064)	(5,702,137)	(5,660,209)	(5,618,282)	(5,576,354)
Book Depreciation	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Sherco Reg Asset	(5,995,629)	(5,953,701)	(5,911,774)	(5,869,847)	(5,827,919)	(5,785,992)	(5,744,064)	(5,702,137)	(5,660,209)	(5,618,282)	(5,576,354)	(5,534,427)
Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(5,995,629)	(5,953,701)	(5,911,774)	(5,869,847)	(5,827,919)	(5,785,992)	(5,744,064)	(5,702,137)	(5,660,209)	(5,618,282)	(5,576,354)	(5,534,427)
Total Sherco Reg Asset Reserve	(5,995,629)	(5,953,701)	(5,911,774)	(5,869,847)	(5,827,919)	(5,785,992)	(5,744,064)	(5,702,137)	(5,660,209)	(5,618,282)	(5,576,354)	(5,534,427)
Total Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(5,995,629)	(5,953,701)	(5,911,774)	(5,869,847)	(5,827,919)	(5,785,992)	(5,744,064)	(5,702,137)	(5,660,209)	(5,618,282)	(5,576,354)	(5,534,427)
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets	14,134,269,744	14,212,644,032	14,297,606,361	14,385,022,171	14,473,895,900	14,537,940,175	14,627,797,848	14,717,677,342	14,805,807,388	14,894,775,904	14,797,358,696	14,890,436,248
Removal Work in Process (RWIP)	56,485,638	48,095,188	45,560,492	47,639,090	51,344,459	53,757,709	56,406,462	56,776,014	56,252,844	57,872,933	58,609,245	58,077,210
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets including RWIP	14,077,784,105	14,164,548,844	14,252,045,869	14,337,383,081	14,422,551,441	14,484,182,466	14,571,391,386	14,660,901,328	14,749,554,544	14,836,902,971	14,738,749,451	14,832,359,037

Footnotes:
(1) Electric Distribution Plant in the schedule above contains NSPM total company a

Electric Distribution Plant - MN												
Accumulated Depreciation Beginning Balance	1,607,793,918	1,614,478,596	1,622,146,178	1,629,216,651	1,637,145,216	1,645,223,165	1,653,439,197	1,661,656,760	1,670,065,964	1,677,656,638	1,686,235,595	1,694,751,094
Book Depreciation	11,967,742	12,107,373	12,242,077	12,381,851	12,519,522	12,658,221	12,798,429	12,939,611	13,081,824	13,228,186	13,366,988	13,493,599
Retirements	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)	(2,950,127)
Book Removals	(2,335,719)	(1,489,671)	(2,221,480)	(1,503,161)	(1,491,448)	(1,492,062)	(1,630,740)	(1,580,281)	(2,541,023)	(1,699,102)	(1,901,362)	(1,508,573)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	2,781	7	4	2	1	1	0	0	0	0	0	0
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant - MN	1,614,478,596	1,622,146,178	1,629,216,651	1,637,145,216	1,645,223,165	1,653,439,197	1,661,656,760	1,670,065,964	1,677,656,638	1,686,235,595	1,694,751,094	1,703,785,993
Electric Distribution Plant - MN RWIP	4,566,343	4,785,920	4,293,515	4,563,405	4,881,980	5,235,095	5,479,728	5,762,421	5,041,763	5,026,470	4,581,842	4,673,991
Total Electric Distribution - MN including RWIP	1,609,912,253	1,617,360,258	1,624,923,136	1,632,581,811	1,640,341,185	1,648,204,102	1,656,177,033	1,664,303,542	1,672,614,874	1,681,209,125	1,690,169,252	1,699,112,002

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
Accumulated Depreciation Beginning Balance	316,128,463	319,105,885	322,162,376	325,254,450	328,349,251	331,444,053	334,547,067	337,649,201	340,737,247	343,806,297	346,849,129	349,862,640
Book Depreciation	2,994,973	3,072,912	3,095,734	3,095,734	3,095,734	3,102,749	3,102,269	3,074,256	3,064,173	3,041,596	3,002,629	3,024,122
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(17,550)	(16,421)	(3,661)	(933)	(933)	265	(134)	13,789	4,878	1,236	10,882	(9,235)
Electric Intangible Plant	319,105,885	322,162,376	325,254,450	328,349,251	331,444,053	334,547,067	337,649,201	340,737,247	343,806,297	346,849,129	349,862,640	352,877,527
Electric Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Electric Intangible including RWIP	319,105,885	322,162,376	325,254,450	328,349,251	331,444,053	334,547,067	337,649,201	340,737,247	343,806,297	346,849,129	349,862,640	352,877,527
Electric Steam Production Plant												
Accumulated Depreciation Beginning Balance	1,720,495,820	1,728,735,923	1,737,036,139	1,745,386,826	1,753,699,598	1,761,655,477	1,770,049,525	1,778,534,637	1,786,952,176	1,795,430,965	1,803,976,105	1,812,522,106
Book Depreciation	8,264,614	8,301,342	8,352,632	8,376,747	8,412,089	8,459,235	8,487,866	8,507,091	8,523,959	8,580,807	8,661,138	8,745,441
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(25,127)	(1,984)	(2,917)	(64,716)	(456,920)	(65,837)	(3,405)	(90,222)	(45,822)	(36,396)	(115,876)	(228,457)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	4	3	5	8	31	6	6	11	10	37	22	15
Transfers & Adjustments	613	855	967	733	679	644	645	658	643	692	716	706
Electric Steam Production Plant	1,728,735,923	1,737,036,139	1,745,386,826	1,753,699,598	1,761,655,477	1,770,049,525	1,778,534,637	1,786,952,176	1,795,430,965	1,803,976,105	1,812,522,106	1,821,039,810
Electric Steam Production Plant RWIP	2,621,884	3,074,402	3,479,519	3,765,176	3,752,034	4,209,673	4,735,297	5,179,743	5,604,701	5,955,701	6,545,598	6,764,758
Total Electric Steam Production including RWIP	1,726,114,039	1,733,961,737	1,741,907,307	1,749,934,422	1,757,903,443	1,765,839,852	1,773,799,341	1,781,772,432	1,789,826,264	1,798,020,404	1,805,976,508	1,814,275,052
Electric Nuclear Production Plant												
Accumulated Depreciation Beginning Balance	2,581,086,985	2,597,317,112	2,613,513,240	2,629,749,903	2,645,992,911	2,662,236,190	2,678,481,061	2,694,718,720	2,710,969,646	2,727,239,167	2,743,569,703	2,759,970,047
Book Depreciation	16,230,125	16,230,361	16,236,662	16,243,006	16,243,277	16,244,870	16,247,657	16,250,924	16,274,520	16,330,534	16,400,343	16,606,482
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	(34,235)	-	-	-	-	(10,000)	-	(5,000)	-	-	(702,804)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	2	2	2	2	2	2	2	1	1	1	1	1
Electric Nuclear Production Plant	2,597,317,112	2,613,513,240	2,629,749,903	2,645,992,911	2,662,236,190	2,678,481,061	2,694,718,720	2,710,969,646	2,727,239,167	2,743,569,703	2,759,970,047	2,775,873,726
Electric Nuclear Production Plant RWIP	209,643	180,408	185,408	185,408	190,408	190,408	180,408	185,408	255,408	882,908	932,908	230,104
Total Electric Nuclear Production including RWIP	2,597,107,469	2,613,332,832	2,629,564,495	2,645,807,503	2,662,045,782	2,678,290,654	2,694,538,312	2,710,784,238	2,726,983,759	2,742,686,795	2,759,037,139	2,775,643,622
Electric Hydro Production Plant												
Accumulated Depreciation Beginning Balance	20,557,503	20,680,376	20,803,250	20,926,123	21,048,997	21,171,870	21,294,744	21,417,618	21,540,491	21,663,365	21,786,238	21,909,112
Book Depreciation	122,874	122,874	122,874	122,874	122,874	122,874	122,874	122,874	122,874	122,874	122,874	122,874
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Electric Hydro Production Plant	20,680,376	20,803,250	20,926,123	21,048,997	21,171,870	21,294,744	21,417,618	21,540,491	21,663,365	21,786,238	21,909,112	22,031,985
Electric Hydro Production Plant RWIP	1,313	1,313	1,313	1,313	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Total Electric Hydro Production including RWIP	20,679,064	20,801,937	20,924,811	21,047,684	21,170,558	21,293,432	21,416,305	21,539,179	21,662,052	21,784,926	21,907,800	22,030,673
Electric Other Production Plant												
Accumulated Depreciation Beginning Balance	1,137,663,249	1,157,897,601	1,172,573,845	1,175,416,260	1,195,905,000	1,216,372,741	1,236,540,907	1,257,042,309	1,277,599,709	1,283,376,182	1,303,982,075	1,325,417,306
Book Depreciation	20,289,253	20,292,847	20,394,611	20,497,489	20,504,476	20,511,798	20,542,050	20,575,654	20,632,332	21,053,291	21,485,686	21,570,862
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(54,893)	(5,616,594)	(17,552,892)	(8,745)	(36,731)	(343,624)	(40,640)	(18,252)	(14,855,859)	(447,435)	(50,461)	(708,936)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	647	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(9)	(9)	49	(5)	(4)	(8)	(8)	(2)	(0)	36	7	6
Electric Other Production Plant	1,157,897,601	1,172,573,845	1,175,416,260	1,195,905,000	1,216,372,741	1,236,540,907	1,257,042,309	1,277,599,709	1,283,376,182	1,303,982,075	1,325,417,306	1,346,279,238
Electric Other Production Plant RWIP	46,111,986	41,497,506	24,187,692	24,406,658	24,551,295	24,388,968	24,530,032	24,689,548	10,311,957	10,055,051	10,122,673	9,531,820
Total Electric Other Production including RWIP	1,111,785,615	1,131,076,339	1,151,228,568	1,171,498,342	1,191,821,446	1,212,151,939	1,232,512,277	1,252,910,162	1,273,064,226	1,293,927,024	1,315,294,633	1,336,747,417
Electric Transmission Plant												
Accumulated Depreciation Beginning Balance	1,215,849,493	1,222,442,653	1,229,052,777	1,234,610,305	1,241,183,890	1,247,857,266	1,254,112,258	1,260,862,745	1,267,613,961	1,273,870,772	1,280,688,292	1,287,504,618
Book Depreciation	7,861,880	7,866,683	7,889,353	7,911,804	7,911,496	7,949,771	7,988,607	7,989,335	8,022,652	8,055,639	8,055,743	8,129,924
Retirements	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)	(1,238,105)
Book Removals	(30,600)	(18,440)	(1,093,703)	(100,100)	-	(456,659)	-	-	(527,721)	-	(1,298)	(809,470)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(15)	(14)	(16)	(14)	(14)	(15)	(14)	(14)	(14)	(14)	(13)	(14)
Electric Transmission Plant	1,222,442,653	1,229,052,777	1,234,610,305	1,241,183,890	1,247,857,266	1,254,112,258	1,260,862,745	1,267,613,961	1,273,870,772	1,280,688,292	1,287,504,618	1,293,586,953
Electric Transmission Plant RWIP	2,558,875	2,703,128	2,041,527	2,228,068	2,452,109	2,390,608	2,776,412	2,967,116	2,871,101	3,194,868	3,454,499	3,165,621
Total Electric Transmission including RWIP	1,219,883,778	1,226,349,649	1,232,568,778	1,238,955,822	1,245,405,158	1,251,721,650	1,258,086,333	1,264,646,845	1,270,999,671	1,277,493,423	1,284,050,119	1,290,421,332

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant (1)												
Accumulated Depreciation Beginning Balance	1,992,951,032	2,001,816,769	2,011,861,853	2,022,007,577	2,032,284,156	2,042,696,061	2,053,239,818	2,063,843,253	2,074,550,457	2,085,316,767	2,096,546,688	2,108,000,750
Book Depreciation	14,953,827	15,084,930	15,214,502	15,344,036	15,473,224	15,612,583	15,754,555	15,889,058	16,015,719	16,179,066	16,338,280	16,469,094
Retirements	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)	(3,420,719)
Book Removals	(2,667,371)	(1,619,127)	(1,648,060)	(1,646,738)	(1,640,600)	(1,648,107)	(1,730,402)	(1,761,135)	(1,828,691)	(1,528,427)	(1,463,500)	(1,496,419)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	(0)
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant	2,001,816,769	2,011,861,853	2,022,007,577	2,032,284,156	2,042,696,061	2,053,239,818	2,063,843,253	2,074,550,457	2,085,316,767	2,096,546,688	2,108,000,750	2,119,552,706
Electric Distribution Plant RWIP	4,705,066	4,885,441	5,044,936	5,250,578	5,481,518	5,758,551	6,099,539	6,397,327	6,380,853	6,476,868	6,468,571	6,581,714
Total Electric Distribution including RWIP	1,997,111,702	2,006,976,412	2,016,962,641	2,027,033,578	2,037,214,542	2,047,481,267	2,057,743,714	2,068,153,130	2,078,935,913	2,090,069,820	2,101,532,178	2,112,970,992
Electric General Plant												
Accumulated Depreciation Beginning Balance	473,466,649	479,218,437	484,977,311	490,646,634	496,481,888	502,325,218	508,094,465	514,013,777	519,972,035	525,833,188	531,909,650	538,107,247
Book Depreciation	5,748,527	5,746,095	5,778,999	5,829,603	5,864,623	5,888,851	5,923,461	5,958,435	6,023,904	6,070,133	6,187,658	6,394,107
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(14,908)	(14,294)	(142,368)	(13,641)	(14,150)	(118,097)	(18,081)	(19,727)	(183,729)	(20,561)	(20,484)	(200,564)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	18,169	27,072	32,692	19,293	(7,143)	(1,506)	13,932	19,550	20,978	26,890	30,423	30,458
Electric General Plant	479,218,437	484,977,311	490,646,634	496,481,888	502,325,218	508,094,465	514,013,777	519,972,035	525,833,188	531,909,650	538,107,247	544,331,248
Electric General Plant RWIP	2,383,822	2,816,969	2,772,042	2,867,825	3,027,958	3,085,765	3,231,329	3,385,247	3,337,580	3,428,764	3,500,306	3,394,578
Total Electric General including RWIP	476,834,615	482,160,342	487,874,592	493,614,063	499,297,259	505,008,700	510,782,448	516,586,788	522,495,608	528,480,886	534,606,941	540,936,670
Total Electric Utility	9,527,214,757	9,591,980,792	9,643,998,080	9,714,945,691	9,785,758,876	9,856,359,846	9,928,082,260	9,999,935,721	10,056,536,704	10,129,307,879	10,203,293,826	10,275,573,194
Total Electric Utility RWIP	58,592,589	55,159,167	37,712,437	38,705,024	39,456,635	40,025,286	41,554,329	42,805,702	28,762,913	29,995,472	31,025,868	29,669,907
Total Electric Utility including RWIP	9,468,622,167	9,536,821,624	9,606,285,643	9,676,240,666	9,746,302,241	9,816,334,560	9,886,527,931	9,957,130,019	10,027,773,791	10,099,312,407	10,172,267,958	10,245,903,287
Common Intangible Plant												
Accumulated Depreciation Beginning Balance	476,244,560	483,092,429	489,946,265	496,798,948	503,648,815	510,488,927	517,313,520	524,107,757	530,858,977	537,625,557	544,349,299	550,719,397
Book Depreciation	6,848,313	6,853,033	6,837,515	6,849,642	6,832,441	6,805,862	6,795,548	6,779,122	6,769,070	6,702,695	6,396,980	6,704,314
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	(443)	803	15,169	225	7,672	18,731	(1,312)	(27,902)	(2,490)	21,048	(26,882)	(1,228)
Common Intangible Plant	483,092,429	489,946,265	496,798,948	503,648,815	510,488,927	517,313,520	524,107,757	530,858,977	537,625,557	544,349,299	550,719,397	557,422,484
Common Intangible Plant RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Common Intangible including RWIP	483,092,429	489,946,265	496,798,948	503,648,815	510,488,927	517,313,520	524,107,757	530,858,977	537,625,557	544,349,299	550,719,397	557,422,484
Common General Plant												
Accumulated Depreciation Beginning Balance	247,662,893	252,535,463	257,344,883	261,544,203	266,495,819	271,446,493	276,417,618	281,046,366	285,393,737	289,775,325	294,199,211	298,630,347
Book Depreciation	4,827,390	4,768,551	4,819,147	4,872,104	4,863,089	4,883,828	4,937,887	4,723,301	4,437,567	4,395,260	4,406,673	4,530,279
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	(341)	(58,883)	(718,445)	(319)	(314)	(311)	(319)	(325)	(329)	(5,451)	(314)	(321)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	2	1	1	1	1	0	0	0	0	0	0	0
Transfers & Adjustments	45,518	99,752	98,617	79,829	87,899	87,608	(308,820)	(375,605)	(55,650)	34,077	24,776	39,845
Common General Plant	252,535,463	257,344,883	261,544,203	266,495,819	271,446,493	276,417,618	281,046,366	285,393,737	289,775,325	294,199,211	298,630,347	303,200,150
Common General Plant RWIP	733,229	674,645	(43,501)	(41,021)	(22,237)	(4,208)	13,828	31,858	49,884	62,586	78,870	95,174
Total Common General including RWIP	251,802,234	256,670,238	261,587,704	266,536,840	271,468,729	276,421,826	281,032,538	285,361,879	289,725,441	294,136,625	298,551,477	303,104,976
Total Common Utility	735,627,892	747,291,148	758,343,152	770,144,633	781,935,420	793,731,138	805,154,123	816,252,714	827,400,882	838,548,510	849,349,744	860,622,634
Total Common Utility RWIP	733,229	674,645	(43,501)	(41,021)	(22,237)	(4,208)	13,828	31,858	49,884	62,586	78,870	95,174
Total Common Utility including RWIP	734,894,663	746,616,503	758,386,653	770,185,654	781,957,656	793,735,346	805,140,295	816,220,856	827,350,997	838,485,925	849,270,874	860,527,460

Functional Class	2024 January	February	March	April	May	June	July	August	September	October	November	December
Nuclear Fuel												
Accumulated Depreciation Beginning Balance	3,008,259,761	3,018,647,719	3,028,384,730	3,038,772,688	3,048,835,171	3,059,223,129	3,069,285,612	3,079,673,570	3,090,061,528	3,100,071,368	3,108,176,335	3,117,826,008
Book Depreciation	10,387,958	9,737,011	10,387,958	10,062,483	10,387,958	10,062,483	10,387,958	10,387,958	10,009,840	8,104,967	9,649,673	10,311,196
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear Fuel	3,018,647,719	3,028,384,730	3,038,772,688	3,048,835,171	3,059,223,129	3,069,285,612	3,079,673,570	3,090,061,528	3,100,071,368	3,108,176,335	3,117,826,008	3,128,137,204
Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	3,018,647,719	3,028,384,730	3,038,772,688	3,048,835,171	3,059,223,129	3,069,285,612	3,079,673,570	3,090,061,528	3,100,071,368	3,108,176,335	3,117,826,008	3,128,137,204
Total Nuclear Fuel	3,018,647,719	3,028,384,730	3,038,772,688	3,048,835,171	3,059,223,129	3,069,285,612	3,079,673,570	3,090,061,528	3,100,071,368	3,108,176,335	3,117,826,008	3,128,137,204
Total Nuclear Fuel RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Nuclear Fuel including RWIP	3,018,647,719	3,028,384,730	3,038,772,688	3,048,835,171	3,059,223,129	3,069,285,612	3,079,673,570	3,090,061,528	3,100,071,368	3,108,176,335	3,117,826,008	3,128,137,204
Decommissioning												
Accumulated Depreciation Beginning Balance	1,903,075,543	1,905,888,821	1,908,702,099	1,911,515,377	1,914,328,655	1,917,141,933	1,919,955,211	1,922,768,489	1,925,581,767	1,928,395,045	1,931,208,323	1,934,021,601
Book Depreciation	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278	2,813,278
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Decommissioning	1,905,888,821	1,908,702,099	1,911,515,377	1,914,328,655	1,917,141,933	1,919,955,211	1,922,768,489	1,925,581,767	1,928,395,045	1,931,208,323	1,934,021,601	1,936,834,879
Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,905,888,821	1,908,702,099	1,911,515,377	1,914,328,655	1,917,141,933	1,919,955,211	1,922,768,489	1,925,581,767	1,928,395,045	1,931,208,323	1,934,021,601	1,936,834,879
Total Decommissioning	1,905,888,821	1,908,702,099	1,911,515,377	1,914,328,655	1,917,141,933	1,919,955,211	1,922,768,489	1,925,581,767	1,928,395,045	1,931,208,323	1,934,021,601	1,936,834,879
Total Decommissioning RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Decommissioning including RWIP	1,905,888,821	1,908,702,099	1,911,515,377	1,914,328,655	1,917,141,933	1,919,955,211	1,922,768,489	1,925,581,767	1,928,395,045	1,931,208,323	1,934,021,601	1,936,834,879
NSPM Theoretical Reserve - Distribution												
Accumulated Depreciation Beginning Balance	(71,910,495)	(71,524,431)	(71,138,366)	(70,752,302)	(70,366,238)	(69,980,173)	(69,594,109)	(69,208,044)	(68,821,980)	(68,435,916)	(68,049,851)	(67,663,787)
Book Depreciation	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064	386,064
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(71,524,431)	(71,138,366)	(70,752,302)	(70,366,238)	(69,980,173)	(69,594,109)	(69,208,044)	(68,821,980)	(68,435,916)	(68,049,851)	(67,663,787)	(67,277,722)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(71,524,431)	(71,138,366)	(70,752,302)	(70,366,238)	(69,980,173)	(69,594,109)	(69,208,044)	(68,821,980)	(68,435,916)	(68,049,851)	(67,663,787)	(67,277,722)
NSPM Theoretical Reserve - Transmission												
Accumulated Depreciation Beginning Balance	(124,813,339)	(124,518,291)	(124,223,242)	(123,928,194)	(123,633,146)	(123,338,097)	(123,043,049)	(122,748,001)	(122,452,952)	(122,157,904)	(121,862,856)	(121,567,807)
Book Depreciation	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048	295,048
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(124,518,291)	(124,223,242)	(123,928,194)	(123,633,146)	(123,338,097)	(123,043,049)	(122,748,001)	(122,452,952)	(122,157,904)	(121,862,856)	(121,567,807)	(121,272,759)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(124,518,291)	(124,223,242)	(123,928,194)	(123,633,146)	(123,338,097)	(123,043,049)	(122,748,001)	(122,452,952)	(122,157,904)	(121,862,856)	(121,567,807)	(121,272,759)

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
NSPM Theoretical Reserve - General and Intangible												
Accumulated Depreciation Beginning Balance	(747,441)	(740,095)	(732,750)	(725,404)	(718,058)	(710,712)	(703,367)	(696,021)	(688,675)	(681,330)	(673,984)	(666,638)
Book Depreciation	7,346	7,346	7,346	7,346	7,346	7,346	7,346	7,346	7,346	7,346	7,346	7,346
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
NSPM Theoretical Reserve	(740,095)	(732,750)	(725,404)	(718,058)	(710,712)	(703,367)	(696,021)	(688,675)	(681,330)	(673,984)	(666,638)	(659,293)
NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(740,095)	(732,750)	(725,404)	(718,058)	(710,712)	(703,367)	(696,021)	(688,675)	(681,330)	(673,984)	(666,638)	(659,293)
Total NSPM Theoretical Reserve	(196,782,817)	(196,094,358)	(195,405,900)	(194,717,441)	(194,028,983)	(193,340,525)	(192,652,066)	(191,963,608)	(191,275,149)	(190,586,691)	(189,898,232)	(189,209,774)
Total NSPM Theoretical Reserve RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total NSPM Theoretical Reserve including RWIP	(196,782,817)	(196,094,358)	(195,405,900)	(194,717,441)	(194,028,983)	(193,340,525)	(192,652,066)	(191,963,608)	(191,275,149)	(190,586,691)	(189,898,232)	(189,209,774)
Sherco Reg Asset												
Accumulated Depreciation Beginning Balance	(5,534,427)	(5,492,499)	(5,450,572)	(5,408,644)	(5,366,717)	(5,324,789)	(5,282,862)	(5,240,934)	(5,199,007)	(5,157,079)	(5,115,152)	(5,073,224)
Book Depreciation	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927	41,927
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Book Removals	-	-	-	-	-	-	-	-	-	-	-	-
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	-	-	-	-	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Sherco Reg Asset	(5,492,499)	(5,450,572)	(5,408,644)	(5,366,717)	(5,324,789)	(5,282,862)	(5,240,934)	(5,199,007)	(5,157,079)	(5,115,152)	(5,073,224)	(5,031,297)
Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(5,492,499)	(5,450,572)	(5,408,644)	(5,366,717)	(5,324,789)	(5,282,862)	(5,240,934)	(5,199,007)	(5,157,079)	(5,115,152)	(5,073,224)	(5,031,297)
Total Sherco Reg Asset Reserve	(5,492,499)	(5,450,572)	(5,408,644)	(5,366,717)	(5,324,789)	(5,282,862)	(5,240,934)	(5,199,007)	(5,157,079)	(5,115,152)	(5,073,224)	(5,031,297)
Total Sherco Reg Asset RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Total Sherco Reg Asset including RWIP	(5,492,499)	(5,450,572)	(5,408,644)	(5,366,717)	(5,324,789)	(5,282,862)	(5,240,934)	(5,199,007)	(5,157,079)	(5,115,152)	(5,073,224)	(5,031,297)
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets	14,985,103,872	15,074,813,839	15,151,814,752	15,248,169,991	15,344,705,585	15,440,708,420	15,537,785,441	15,634,669,115	15,715,971,769	15,811,539,205	15,909,519,722	16,006,926,839
Removal Work in Process (RWIP)	59,325,819	55,833,813	37,668,936	38,664,004	39,434,398	40,021,078	41,568,157	42,837,560	28,812,797	30,058,058	31,104,738	29,765,081
Total Electric, Common, Nuclear Fuel, Decommissioning, and Regulatory Assets including RWIP	14,925,778,054	15,018,980,026	15,114,145,816	15,209,505,988	15,305,271,187	15,400,687,343	15,496,217,285	15,591,831,555	15,687,158,972	15,781,481,147	15,878,414,984	15,977,161,758

Footnotes:
(1) Electric Distribution Plant in the schedule above contains NSPM total company a

Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
Accumulated Depreciation Beginning Balance	1,703,785,993	1,712,516,617	1,721,760,947	1,731,101,939	1,740,567,147	1,750,163,295	1,759,883,851	1,769,661,525	1,779,541,759	1,789,544,432	1,799,936,148	1,810,545,160
Book Depreciation	13,624,954	13,752,009	13,877,608	14,003,214	14,128,485	14,260,491	14,394,953	14,525,138	14,647,372	14,806,242	14,961,167	15,087,823
Retirements	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)	(3,004,680)
Book Removals	(1,889,649)	(1,502,999)	(1,531,936)	(1,533,326)	(1,527,657)	(1,535,255)	(1,612,599)	(1,640,225)	(1,640,018)	(1,409,846)	(1,347,475)	(1,376,996)
Gain/Loss	-	-	-	-	-	-	-	-	-	-	-	-
Salvage	(0)	0	0	0	0	(0)	(0)	(0)	0	0	0	(0)
Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant - MN	1,712,516,617	1,721,760,947	1,731,101,939	1,740,567,147	1,750,163,295	1,759,883,851	1,769,661,525	1,779,541,759	1,789,544,432	1,799,936,148	1,810,545,160	1,821,251,307
Electric Distribution Plant - MN RWIP	4,472,565	4,646,112	4,798,652	4,990,589	5,206,759	5,468,332	5,798,163	6,087,971	6,131,144	6,231,481	6,226,143	6,331,713
Total Electric Distribution - MN including RWIP	1,708,044,053	1,717,114,836	1,726,303,287	1,735,576,558	1,744,956,536	1,754,415,520	1,763,863,362	1,773,453,787	1,783,413,288	1,793,704,667	1,804,319,017	1,814,919,593

Functional Class	2021											
	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
RWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Closings	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant												
RWIP Beginning Balance	7,502,110	8,501,758	7,531,608	8,125,772	8,106,919	7,939,278	8,147,649	6,146,330	6,143,419	6,064,581	6,051,672	2,196,758
RWIP Expenditures	999,648	691,920	594,106	(18,852)	(343,535)	744,654	604,146	317,052	(15,972)	296,393	111,983	127,149
RWIP Closings	-	(1,662,070)	58	(2)	175,895	(536,283)	(2,605,466)	(319,963)	(62,866)	(309,302)	(3,966,896)	(430,572)
Electric Steam Production RWIP	8,501,758	7,531,608	8,125,772	8,106,919	7,939,278	8,147,649	6,146,330	6,143,419	6,064,581	6,051,672	2,196,758	1,893,334
Electric Nuclear Production Plant												
RWIP Beginning Balance	4,266,934	4,130,899	4,579,837	5,238,480	5,943,897	3,910,480	4,167,203	4,004,541	2,375,780	2,116,794	2,251,933	2,119,490
RWIP Expenditures	(136,044)	638,605	658,661	774,545	(2,033,436)	256,723	211,087	46,830	534,022	393,334	107,205	445,882
RWIP Closings	9	(189,666)	(18)	(69,127)	18	-	(373,748)	(1,675,592)	(793,007)	(258,195)	(239,648)	(903,765)
Electric Nuclear Production RWIP	4,130,899	4,579,837	5,238,480	5,943,897	3,910,480	4,167,203	4,004,541	2,375,780	2,116,794	2,251,933	2,119,490	1,661,606
Electric Hydro Production Plant												
RWIP Beginning Balance	23,856	25,056	23,935	24,628	25,127	26,560	27,650	1,685	1,648	1,614	9,493	10,921
RWIP Expenditures	1,200	(1,121)	694	499	1,433	1,090	-	-	-	8,000	1,500	500
RWIP Closings	-	-	-	-	-	-	(25,965)	(37)	(34)	(121)	(73)	(10,049)
Electric Hydro Production RWIP	25,056	23,935	24,628	25,127	26,560	27,650	1,685	1,648	1,614	9,493	10,921	1,372
Electric Other Production Plant												
RWIP Beginning Balance	22,996,743	23,148,651	22,471,670	33,046,491	23,442,782	24,022,281	22,257,835	21,198,057	21,391,995	22,214,241	21,532,986	21,258,870
RWIP Expenditures	151,908	1,032,593	10,826,795	(9,584,572)	588,990	(1,690,373)	133,628	266,542	931,092	809,385	54,529	232,745
RWIP Closings	-	(1,709,574)	(251,973)	(19,137)	(9,491)	(74,074)	(1,193,406)	(72,603)	(108,847)	(1,490,640)	(328,644)	(928,279)
Electric Other Production RWIP	23,148,651	22,471,670	33,046,491	23,442,782	24,022,281	22,257,835	21,198,057	21,391,995	22,214,241	21,532,986	21,258,870	20,563,337
Electric Transmission Plant												
RWIP Beginning Balance	26,723,202	29,038,955	28,648,036	30,316,731	30,317,775	31,506,725	24,768,976	16,217,937	15,414,286	12,559,698	11,430,833	11,583,484
RWIP Expenditures	2,317,215	1,127,191	1,776,291	1,634,448	1,198,093	(3,303,829)	131,309	278,740	197,506	225,363	177,681	189,990
RWIP Closings	(1,462)	(1,518,110)	(107,596)	(1,633,403)	(9,144)	(3,433,920)	(8,682,349)	(1,082,391)	(3,052,094)	(1,354,228)	(25,030)	(2,897,772)
Electric Transmission RWIP	29,038,955	28,648,036	30,316,731	30,317,775	31,506,725	24,768,976	16,217,937	15,414,286	12,559,698	11,430,833	11,583,484	8,875,702
Electric Distribution Plant (1)												
RWIP Beginning Balance	9,407,834	8,009,459	6,662,179	6,830,865	6,945,442	7,440,282	6,888,897	7,230,574	7,435,825	7,196,455	6,955,270	5,455,347
RWIP Expenditures	281,744	906,716	1,677,992	2,354,040	1,640,905	934,751	1,580,020	1,614,595	1,527,936	1,447,017	1,325,046	1,296,175
RWIP Closings	(1,680,119)	(2,253,996)	(1,509,306)	(2,239,463)	(1,146,066)	(1,486,136)	(1,238,343)	(1,409,344)	(1,767,306)	(1,688,202)	(2,824,968)	(1,593,367)
Electric Distribution RWIP	8,009,459	6,662,179	6,830,865	6,945,442	7,440,282	6,888,897	7,230,574	7,435,825	7,196,455	6,955,270	5,455,347	5,158,155
Electric General Plant												
RWIP Beginning Balance	(519,211)	(496,663)	(622,623)	(643,237)	(762,368)	(765,915)	(473,723)	760,184	787,075	821,277	855,383	731,854
RWIP Expenditures	27,383	(109,176)	(20,614)	(83,728)	(3,548)	42,843	54,991	55,706	55,164	49,691	29,562	43,036
RWIP Closings	(4,835)	(16,784)	-	(35,403)	-	249,350	1,178,916	(28,815)	(20,962)	(15,585)	(153,091)	(17,974)
Electric General RWIP	(496,663)	(622,623)	(643,237)	(762,368)	(765,915)	(473,723)	760,184	787,075	821,277	855,383	731,854	756,916
Total Electric Utility	72,358,114	69,294,642	82,939,730	74,019,575	74,079,691	65,784,488	55,559,309	53,550,027	50,974,659	49,087,569	43,356,724	38,910,422
Common General Plant												
RWIP Beginning Balance	(893,939)	(854,639)	(794,143)	(783,454)	(709,957)	(576,118)	1,729,431	1,128,982	1,156,235	1,062,582	1,325,256	1,583,930
RWIP Expenditures	39,299	59,784	10,691	73,497	133,839	234,743	37,650	49,263	102,121	278,714	272,933	265,802
RWIP Closings	0	712	(2)	-	-	2,070,805	(638,099)	(22,010)	(195,775)	(16,039)	(14,259)	(43,559)
Common General RWIP	(854,639)	(794,143)	(783,454)	(709,957)	(576,118)	1,729,431	1,128,982	1,156,235	1,062,582	1,325,256	1,583,930	1,806,172
Total Common Utility	(854,639)	(794,143)	(783,454)	(709,957)	(576,118)	1,729,431	1,128,982	1,156,235	1,062,582	1,325,256	1,583,930	1,806,172
Total Electric and Common Utility	71,503,475	68,500,498	82,156,276	73,309,619	73,503,573	67,513,919	56,688,291	54,706,263	52,037,240	50,412,825	44,940,654	40,716,594

Footnotes:
(1) Electric Distribution Plant in the schedule above contains NSPM total company all jurisdictions. Below is the Electric Distribution State of MN only

Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
RWIP Beginning Balance	8,218,113	6,924,912	5,702,440	5,769,570	5,798,014	6,210,401	5,638,526	6,678,686	6,855,249	6,578,151	6,290,579	4,717,080
RWIP Expenditures	238,981	848,688	1,471,991	2,167,385	1,467,907	729,260	1,399,628	1,350,727	1,248,984	1,137,705	1,006,095	981,967
RWIP Closings	(1,532,182)	(2,071,160)	(1,404,861)	(2,138,941)	(1,055,519)	(1,301,135)	(359,468)	(1,174,163)	(1,526,082)	(1,425,276)	(2,579,594)	(1,339,055)
Electric Distribution RWIP - MN	6,924,912	5,702,440	5,769,570	5,798,014	6,210,401	5,638,526	6,678,686	6,855,249	6,578,151	6,290,579	4,717,080	4,359,992

Northern States Power Company
Roll Forward by Functional Class
RWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 34 of 36

	2022											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
RWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	14,900	14,900
RWIP Expenditures	-	-	-	-	-	-	-	-	-	14,900	-	-
RWIP Closings	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible RWIP	-	-	-	-	-	-	-	-	-	14,900	14,900	14,900
Electric Steam Production Plant												
RWIP Beginning Balance	1,893,334	1,835,467	2,125,864	2,822,759	3,603,382	4,800,639	5,353,216	5,854,165	7,138,482	11,032,420	11,460,105	11,544,629
RWIP Expenditures	215,331	856,587	715,177	790,846	1,257,104	1,173,839	1,148,475	1,625,925	3,905,386	474,702	325,566	52,286
RWIP Closings	(273,198)	(566,190)	(18,282)	(10,223)	(59,847)	(621,262)	(647,526)	(341,608)	(11,448)	(47,017)	(241,042)	(1,840,567)
Electric Steam Production RWIP	1,835,467	2,125,864	2,822,759	3,603,382	4,800,639	5,353,216	5,854,165	7,138,482	11,032,420	11,460,105	11,544,629	9,756,349
Electric Nuclear Production Plant												
RWIP Beginning Balance	1,661,606	1,925,160	1,930,801	1,670,342	3,339,641	872,099	872,099	874,099	919,099	1,076,769	1,331,669	1,489,669
RWIP Expenditures	263,554	259,128	78,030	1,986,905	98,753	-	27,000	50,000	599,680	254,900	160,000	100,000
RWIP Closings	-	(253,486)	(338,489)	(317,606)	(2,566,295)	-	(25,000)	(5,000)	(442,010)	-	(2,000)	(449,087)
Electric Nuclear Production RWIP	1,925,160	1,930,801	1,670,342	3,339,641	872,099	872,099	874,099	919,099	1,076,769	1,331,669	1,489,669	1,140,583
Electric Hydro Production Plant												
RWIP Beginning Balance	1,372	1,371	1,369	1,368	1,365	1,354	1,352	1,350	1,346	1,343	1,331	1,323
RWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Closings	(1)	(1)	(2)	(3)	(11)	(2)	(2)	(4)	(3)	(12)	(7)	(5)
Electric Hydro Production RWIP	1,371	1,369	1,368	1,365	1,354	1,352	1,350	1,346	1,343	1,331	1,323	1,318
Electric Other Production Plant												
RWIP Beginning Balance	20,563,337	20,279,424	20,411,340	19,225,987	19,360,117	24,197,943	28,870,766	33,572,714	33,812,798	34,221,898	34,601,286	34,646,236
RWIP Expenditures	41,143	137,083	283,782	146,187	4,950,455	4,895,421	4,887,598	275,426	567,650	447,326	162,822	480,459
RWIP Closings	(325,057)	(5,167)	(1,469,135)	(12,057)	(112,629)	(222,599)	(185,649)	(35,342)	(158,551)	(67,938)	(117,872)	(1,295,995)
Electric Other Production RWIP	20,279,424	20,411,340	19,225,987	19,360,117	24,197,943	28,870,766	33,572,714	33,812,798	34,221,898	34,601,286	34,646,236	33,830,701
Electric Transmission Plant												
RWIP Beginning Balance	8,875,702	9,086,132	8,260,234	1,837,589	2,125,870	2,177,310	2,065,352	2,373,992	2,446,109	2,504,124	2,866,944	3,231,161
RWIP Expenditures	310,694	277,955	385,747	288,480	294,144	348,308	311,306	233,810	469,218	362,870	400,188	492,295
RWIP Closings	(100,264)	(1,103,852)	(6,808,392)	(200)	(242,704)	(460,266)	(2,666)	(161,693)	(411,203)	(50)	(35,971)	(469,518)
Electric Transmission RWIP	9,086,132	8,260,234	1,837,589	2,125,870	2,177,310	2,065,352	2,373,992	2,446,109	2,504,124	2,866,944	3,231,161	3,253,938
Electric Distribution Plant (1)												
RWIP Beginning Balance	5,158,155	5,058,491	5,050,571	4,044,742	4,309,463	4,587,545	4,966,748	5,347,863	5,685,773	5,842,170	5,923,039	5,928,230
RWIP Expenditures	1,736,072	1,743,470	1,751,943	1,817,070	1,845,422	1,906,064	1,982,852	1,962,554	1,889,166	1,692,546	1,617,546	1,764,017
RWIP Closings	(1,835,736)	(1,751,389)	(2,757,772)	(1,552,349)	(1,567,340)	(1,526,861)	(1,601,738)	(1,624,644)	(1,732,769)	(1,611,677)	(1,612,355)	(1,653,090)
Electric Distribution RWIP	5,058,491	5,050,571	4,044,742	4,309,463	4,587,545	4,966,748	5,347,863	5,685,773	5,842,170	5,923,039	5,928,230	6,039,157
Electric General Plant												
RWIP Beginning Balance	756,916	781,978	808,390	614,633	670,826	743,239	788,164	802,113	819,804	669,721	854,272	926,648
RWIP Expenditures	41,833	41,833	46,416	68,297	84,555	83,161	94,999	94,965	93,393	197,603	109,800	105,250
RWIP Closings	(16,771)	(15,420)	(240,173)	(12,104)	(12,142)	(38,236)	(81,050)	(77,274)	(243,476)	(13,052)	(37,424)	(167,482)
Electric General RWIP	781,978	808,390	614,633	670,826	743,239	788,164	802,113	819,804	669,721	854,272	926,648	864,416
Total Electric Utility	38,968,021	38,588,571	30,217,420	33,410,664	37,380,129	42,917,697	48,826,295	50,823,411	55,348,445	57,053,545	57,782,797	54,901,361
Common General Plant												
RWIP Beginning Balance	1,806,172	1,795,874	1,700,319	957,158	994,780	1,111,474	1,240,229	1,371,329	1,501,855	1,484,763	1,556,912	1,222,138
RWIP Expenditures	281	731	32,769	42,837	120,842	132,068	133,769	132,692	120,877	102,097	102,058	99,095
RWIP Closings	(10,579)	(96,287)	(775,930)	(5,216)	(4,148)	(3,313)	(2,670)	(2,165)	(137,969)	(29,948)	(436,832)	(1,011)
Common General RWIP	1,795,874	1,700,319	957,158	994,780	1,111,474	1,240,229	1,371,329	1,501,855	1,484,763	1,556,912	1,222,138	1,320,222
Total Common Utility	1,795,874	1,700,319	957,158	994,780	1,111,474	1,240,229	1,371,329	1,501,855	1,484,763	1,556,912	1,222,138	1,320,222
Total Electric and Common Utility	40,763,896	40,288,890	31,174,578	34,405,443	38,491,603	44,157,926	50,197,624	52,325,267	56,833,208	58,610,457	59,004,935	56,221,583

Footnotes:
(1) Electric Distribution Plant in the schedule ab

Electric Distribution Plant - MN												
RWIP Beginning Balance	4,359,992	4,233,932	4,391,635	3,509,923	3,750,563	3,985,802	4,309,060	4,629,246	4,907,944	5,015,220	5,073,284	5,077,508
RWIP Expenditures	1,519,892	1,529,242	1,536,663	1,587,055	1,611,243	1,663,363	1,725,860	1,713,463	1,649,663	1,476,881	1,432,915	1,566,545
RWIP Closings	(1,645,951)	(1,371,539)	(2,418,375)	(1,346,415)	(1,376,005)	(1,340,105)	(1,405,674)	(1,434,766)	(1,542,388)	(1,418,817)	(1,428,691)	(1,466,411)
Electric Distribution RWIP - MN	4,233,932	4,391,635	3,509,923	3,750,563	3,985,802	4,309,060	4,629,246	4,907,944	5,015,220	5,073,284	5,077,508	5,177,642

Northern States Power Company
Roll Forward by Functional Class
RWIP

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 2
Page 35 of 36

	2023											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
RWIP Beginning Balance	14,900	15,000	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100
RWIP Expenditures	100	100	-	-	-	-	-	-	-	-	-	-
RWIP Closings	-	-	-	-	-	-	-	-	-	-	-	(15,100)
Electric Intangible RWIP	15,000	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	15,100	-
Electric Steam Production Plant												
RWIP Beginning Balance	9,756,349	9,811,772	1,126,975	1,420,101	1,426,824	1,356,335	1,139,388	1,152,077	1,254,746	1,387,476	1,455,903	1,574,721
RWIP Expenditures	264,845	359,895	295,894	86,197	127,513	79,453	72,497	204,003	148,153	99,153	306,653	72,244
RWIP Closings	(209,421)	(9,044,693)	(2,767)	(79,474)	(198,002)	(296,400)	(59,807)	(101,334)	(15,424)	(30,726)	(187,835)	249,529
Electric Steam Production RWIP	9,811,772	1,126,975	1,420,101	1,426,824	1,356,335	1,139,388	1,152,077	1,254,746	1,387,476	1,455,903	1,574,721	1,896,494
Electric Nuclear Production Plant												
RWIP Beginning Balance	1,140,583	1,990,583	1,771,503	1,821,503	2,758,850	2,937,750	2,962,814	2,295,696	1,114,987	530,283	1,124,643	1,124,643
RWIP Expenditures	850,000	120,000	50,000	947,347	178,900	25,064	-	55,000	362,375	666,735	-	-
RWIP Closings	-	(339,080)	-	(10,000)	-	-	(667,117)	(1,235,709)	(947,080)	(72,375)	-	(915,000)
Electric Nuclear Production RWIP	1,990,583	1,771,503	1,821,503	2,758,850	2,937,750	2,962,814	2,295,696	1,114,987	530,283	1,124,643	1,124,643	209,643
Electric Hydro Production Plant												
RWIP Beginning Balance	1,318	1,318	1,318	1,318	1,317	1,316	1,316	1,316	1,316	1,315	1,314	1,313
RWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Closings	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)
Electric Hydro Production RWIP	1,318	1,318	1,318	1,317	1,316	1,316	1,316	1,316	1,315	1,314	1,313	1,313
Electric Other Production Plant												
RWIP Beginning Balance	33,830,701	33,688,528	34,029,812	34,789,469	35,388,594	38,318,547	40,395,984	42,823,301	43,329,092	44,278,951	44,775,525	45,314,024
RWIP Expenditures	64,774	356,307	767,586	612,852	2,987,747	2,980,747	2,997,747	589,272	975,972	609,972	656,669	743,636
RWIP Closings	(206,947)	(15,023)	(7,929)	(13,726)	(57,794)	(903,311)	(570,429)	(83,482)	(26,113)	(113,398)	(118,170)	(528,087)
Electric Other Production RWIP	33,688,528	34,029,812	34,789,469	35,388,594	38,318,547	40,395,984	42,823,301	43,329,092	44,278,951	44,775,525	45,314,024	45,529,572
Electric Transmission Plant												
RWIP Beginning Balance	3,253,938	3,398,601	3,441,899	1,755,149	1,878,510	1,969,428	1,904,526	2,130,404	2,290,213	1,985,819	2,178,360	2,457,983
RWIP Expenditures	219,975	146,865	470,585	172,411	202,722	508,891	225,882	192,237	541,823	289,865	279,627	447,528
RWIP Closings	(75,312)	(103,567)	(2,157,336)	(49,050)	(111,804)	(573,792)	(4)	(32,428)	(846,217)	(97,324)	(4)	(715,705)
Electric Transmission RWIP	3,398,601	3,441,899	1,755,149	1,878,510	1,969,428	1,904,526	2,130,404	2,290,213	1,985,819	2,178,360	2,457,983	2,189,806
Electric Distribution Plant (1)												
RWIP Beginning Balance	6,039,157	5,451,858	5,696,626	5,070,007	5,371,385	5,729,916	6,129,266	6,427,857	6,761,249	5,908,320	5,912,270	5,463,153
RWIP Expenditures	1,938,389	1,918,661	1,938,996	1,994,721	2,032,625	2,074,125	2,124,583	2,104,838	2,056,438	1,891,905	1,596,300	1,736,085
RWIP Closings	(2,525,688)	(1,673,893)	(2,565,614)	(1,693,344)	(1,674,094)	(1,674,775)	(1,825,992)	(1,771,446)	(2,909,367)	(1,887,955)	(2,045,417)	(1,637,664)
Electric Distribution RWIP	5,451,858	5,696,626	5,070,007	5,371,385	5,729,916	6,129,266	6,427,857	6,761,249	5,908,320	5,912,270	5,463,153	5,561,574
Electric General Plant												
RWIP Beginning Balance	864,416	912,916	868,695	681,478	777,152	942,276	1,069,701	1,323,040	1,664,864	1,694,559	1,855,331	2,011,983
RWIP Expenditures	84,234	108,202	117,558	109,444	180,618	248,061	270,821	358,253	172,562	176,112	171,774	139,650
RWIP Closings	(35,734)	(152,423)	(304,775)	(13,770)	(15,494)	(120,636)	(17,482)	(16,429)	(142,868)	(15,340)	(15,122)	(196,094)
Electric General RWIP	912,916	868,695	681,478	777,152	942,276	1,069,701	1,323,040	1,664,864	1,694,559	1,855,331	2,011,983	1,955,539
Total Electric Utility	55,270,576	46,951,927	45,554,124	47,617,732	51,270,668	53,618,094	56,168,792	56,431,568	55,801,823	57,318,446	57,962,921	57,343,940
Common General Plant												
RWIP Beginning Balance	1,320,222	1,215,063	1,143,261	6,368	21,359	73,790	139,614	237,670	344,447	451,021	554,487	646,325
RWIP Expenditures	588	838	8,288	15,555	52,938	66,285	98,491	107,192	106,972	103,839	92,192	87,296
RWIP Closings	(105,747)	(72,639)	(1,145,182)	(564)	(506)	(461)	(436)	(415)	(398)	(373)	(354)	(350)
Common General RWIP	1,215,063	1,143,261	6,368	21,359	73,790	139,614	237,670	344,447	451,021	554,487	646,325	733,270
Total Common Utility	1,215,063	1,143,261	6,368	21,359	73,790	139,614	237,670	344,447	451,021	554,487	646,325	733,270
Total Electric and Common Utility	56,485,638	48,095,188	45,560,492	47,639,090	51,344,459	53,757,709	56,406,462	56,776,014	56,252,844	57,872,933	58,609,245	58,077,210

Footnotes:
(1) Electric Distribution Plant in the schedule ab

	January	February	March	April	May	June	July	August	September	October	November	December
Electric Distribution Plant - MN												
RWIP Beginning Balance	5,177,642	4,566,343	4,785,920	4,293,515	4,563,405	4,881,980	5,235,095	5,479,728	5,762,421	5,041,763	5,026,470	4,581,842
RWIP Expenditures	1,721,639	1,709,242	1,729,072	1,773,049	1,810,022	1,845,177	1,875,372	1,862,975	1,820,365	1,683,809	1,456,734	1,600,722
RWIP Closings	(2,332,938)	(1,489,664)	(2,221,477)	(1,503,159)	(1,491,447)	(1,492,062)	(1,630,739)	(1,580,281)	(2,541,023)	(1,699,101)	(1,901,362)	(1,508,573)
Electric Distribution RWIP - MN	4,566,343	4,785,920	4,293,515	4,563,405	4,881,980	5,235,095	5,479,728	5,762,421	5,041,763	5,026,470	4,581,842	4,673,991

	2024											
Functional Class	January	February	March	April	May	June	July	August	September	October	November	December
Electric Intangible Plant												
RWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Closings	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible RWIP	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant												
RWIP Beginning Balance	1,896,494	2,621,884	3,074,402	3,479,519	3,765,176	3,752,034	4,209,673	4,735,297	5,179,743	5,604,701	5,955,701	6,545,598
RWIP Expenditures	750,514	454,499	408,029	350,364	443,747	523,470	529,022	534,658	470,770	387,359	705,751	447,602
RWIP Closings	(25,123)	(1,981)	(2,912)	(64,708)	(456,889)	(65,831)	(3,399)	(90,211)	(45,812)	(36,359)	(115,854)	(228,442)
Electric Steam Production RWIP	2,621,884	3,074,402	3,479,519	3,765,176	3,752,034	4,209,673	4,735,297	5,179,743	5,604,701	5,955,701	6,545,598	6,764,758
Electric Nuclear Production Plant												
RWIP Beginning Balance	209,643	209,643	180,408	185,408	185,408	190,408	190,408	180,408	185,408	255,408	882,908	932,908
RWIP Expenditures	-	5,000	5,000	-	5,000	-	-	5,000	75,000	627,500	50,000	-
RWIP Closings	-	(34,235)	-	-	-	-	(10,000)	-	(5,000)	-	-	(702,804)
Electric Nuclear Production RWIP	209,643	180,408	185,408	185,408	190,408	190,408	180,408	185,408	255,408	882,908	932,908	230,104
Electric Hydro Production Plant												
RWIP Beginning Balance	1,313	1,313	1,313	1,313	1,313	1,312	1,312	1,312	1,312	1,312	1,312	1,312
RWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-
RWIP Closings	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Electric Hydro Production RWIP	1,313	1,313	1,313	1,313	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Electric Other Production Plant												
RWIP Beginning Balance	45,529,572	46,111,986	41,497,506	24,187,692	24,406,658	24,551,295	24,388,968	24,530,032	24,689,548	10,311,957	10,055,051	10,122,673
RWIP Expenditures	637,307	1,002,114	242,432	227,710	181,368	181,297	181,704	177,768	478,268	190,530	118,083	118,083
RWIP Closings	(54,893)	(5,616,594)	(17,552,245)	(8,745)	(36,731)	(343,624)	(40,640)	(18,252)	(14,855,859)	(447,435)	(50,461)	(708,936)
Electric Other Production RWIP	46,111,986	41,497,506	24,187,692	24,406,658	24,551,295	24,388,968	24,530,032	24,689,548	10,311,957	10,055,051	10,122,673	9,531,820
Electric Transmission Plant												
RWIP Beginning Balance	2,189,806	2,558,875	2,703,128	2,041,527	2,228,068	2,452,109	2,390,608	2,776,412	2,967,116	2,871,101	3,194,868	3,454,499
RWIP Expenditures	399,669	162,693	432,102	286,641	224,041	395,159	385,804	190,704	431,706	323,767	260,929	520,591
RWIP Closings	(30,600)	(18,440)	(1,093,703)	(100,100)	-	(456,659)	-	-	(527,721)	-	(1,298)	(809,470)
Electric Transmission RWIP	2,558,875	2,703,128	2,041,527	2,228,068	2,452,109	2,390,608	2,776,412	2,967,116	2,871,101	3,194,868	3,454,499	3,165,621
Electric Distribution Plant (1)												
RWIP Beginning Balance	5,561,574	4,705,066	4,885,441	5,044,936	5,250,578	5,481,518	5,758,551	6,099,539	6,397,327	6,380,853	6,476,868	6,468,571
RWIP Expenditures	1,810,864	1,799,502	1,807,554	1,852,381	1,871,541	1,925,140	2,071,390	2,058,923	1,812,217	1,624,441	1,455,204	1,609,561
RWIP Closings	(2,667,371)	(1,619,127)	(1,648,060)	(1,646,739)	(1,640,600)	(1,648,107)	(1,730,402)	(1,761,135)	(1,828,691)	(1,528,427)	(1,463,500)	(1,496,419)
Electric Distribution RWIP	4,705,066	4,885,441	5,044,936	5,250,578	5,481,518	5,758,551	6,099,539	6,397,327	6,380,853	6,476,868	6,468,571	6,581,714
Electric General Plant												
RWIP Beginning Balance	1,955,539	2,383,822	2,816,969	2,772,042	2,867,825	3,027,958	3,085,765	3,231,329	3,385,247	3,337,580	3,428,764	3,500,306
RWIP Expenditures	443,191	447,441	97,441	109,424	174,284	175,904	163,645	173,645	136,062	111,745	92,026	94,836
RWIP Closings	(14,908)	(14,294)	(142,368)	(13,641)	(14,150)	(118,097)	(18,081)	(19,727)	(183,729)	(20,562)	(20,484)	(200,564)
Electric General RWIP	2,383,822	2,816,969	2,772,042	2,867,825	3,027,958	3,085,765	3,231,329	3,385,247	3,337,580	3,428,764	3,500,306	3,394,578
Total Electric Utility	58,592,589	55,159,167	37,712,437	38,705,024	39,456,635	40,025,286	41,554,329	42,805,702	28,762,913	29,995,472	31,025,868	29,669,907
Common General Plant												
RWIP Beginning Balance	733,270	733,229	674,645	(43,501)	(41,021)	(22,237)	(4,208)	13,828	31,858	49,884	62,586	78,870
RWIP Expenditures	298	298	298	2,798	19,098	18,339	18,355	18,355	18,355	18,152	16,598	16,625
RWIP Closings	(339)	(58,882)	(718,444)	(318)	(314)	(310)	(319)	(325)	(329)	(5,451)	(314)	(321)
Common General RWIP	733,229	674,645	(43,501)	(41,021)	(22,237)	(4,208)	13,828	31,858	49,884	62,586	78,870	95,174
Total Common Utility	733,229	674,645	(43,501)	(41,021)	(22,237)	(4,208)	13,828	31,858	49,884	62,586	78,870	95,174
Total Electric and Common Utility	59,325,819	55,833,813	37,668,936	38,664,004	39,434,398	40,021,078	41,568,157	42,837,560	28,812,797	30,058,058	31,104,738	29,765,081

Footnotes:
(1) Electric Distribution Plant in the schedule ab

Electric Distribution Plant - MN												
RWIP Beginning Balance	4,673,991	4,472,565	4,646,112	4,798,652	4,990,589	5,206,759	5,468,332	5,798,163	6,087,971	6,131,144	6,231,481	6,226,143
RWIP Expenditures	1,688,223	1,676,547	1,684,477	1,725,263	1,743,827	1,796,828	1,942,430	1,930,034	1,683,191	1,510,184	1,342,136	1,482,567
RWIP Closings	(1,889,649)	(1,502,999)	(1,531,936)	(1,533,326)	(1,527,657)	(1,535,255)	(1,612,599)	(1,640,225)	(1,640,018)	(1,409,846)	(1,347,475)	(1,376,996)
Electric Distribution RWIP - MN	4,472,565	4,646,112	4,798,652	4,990,589	5,206,759	5,468,332	5,798,163	6,087,971	6,131,144	6,231,481	6,226,143	6,331,713

Northern States Power Company
CWIP by Year

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 1 of 49

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
2021													
CWIP Beginning Balance	1,282,671,284	989,336,602	1,065,893,693	1,102,409,155	1,090,682,633	816,079,133	907,750,926	995,587,800	1,081,985,468	1,092,859,885	1,132,424,314	1,198,636,465	1,282,671,284
CWIP Expenditures	75,712,392	102,644,424	371,105,601	82,145,126	128,998,307	144,725,860	152,912,464	132,169,458	185,259,146	105,181,815	126,445,189	135,904,249	1,743,204,031
AFUDC Debt	1,523,102	1,815,257	1,711,350	1,681,908	1,465,018	1,310,127	1,460,885	1,595,015	1,685,537	1,687,171	1,770,586	1,303,883	19,009,839
AFUDC Equity	3,556,113	4,401,102	4,083,088	4,022,915	3,493,463	3,124,341	3,483,854	3,803,721	4,019,595	4,023,491	4,222,415	3,109,443	45,343,541
Closings to Plant	(374,126,288)	(32,303,692)	(340,384,577)	(99,576,472)	(408,560,289)	(57,488,535)	(70,020,330)	(51,170,526)	(180,089,861)	(71,328,049)	(66,226,038)	(820,063,445)	(2,571,338,100)
CWIP Ending Balance	989,336,602	1,065,893,693	1,102,409,155	1,090,682,633	816,079,133	907,750,926	995,587,800	1,081,985,468	1,092,859,885	1,132,424,314	1,198,636,465	518,890,594	518,890,594
2022													
CWIP Beginning Balance	518,890,594	647,768,759	705,114,720	745,560,011	842,955,341	939,389,158	1,023,874,581	1,151,549,200	1,233,621,955	1,258,514,807	1,322,636,602	1,404,091,821	518,890,594
CWIP Expenditures	171,357,640	99,461,442	110,916,888	148,990,825	164,893,029	177,531,513	194,927,577	171,045,198	175,939,673	160,544,474	149,595,394	240,641,388	1,965,845,041
AFUDC Debt	810,269	948,004	1,016,322	1,115,003	1,256,190	1,387,955	1,539,101	1,694,377	1,773,071	1,831,891	1,930,614	1,594,672	16,897,469
AFUDC Equity	1,961,177	2,294,552	2,459,909	2,698,756	3,040,487	3,359,410	3,725,244	4,101,075	4,291,546	4,433,914	4,672,863	3,859,748	40,898,684
Closings to Plant	(45,250,922)	(45,358,038)	(73,947,829)	(55,409,254)	(72,755,889)	(97,793,456)	(72,517,303)	(94,767,895)	(157,111,439)	(102,688,484)	(74,743,652)	(835,194,094)	(1,727,538,254)
CWIP Ending Balance	647,768,759	705,114,720	745,560,011	842,955,341	939,389,158	1,023,874,581	1,151,549,200	1,233,621,955	1,258,514,807	1,322,636,602	1,404,091,821	814,993,534	814,993,534
2023													
CWIP Beginning Balance	814,993,534	868,327,292	963,732,186	906,165,895	931,412,855	999,718,856	1,049,877,631	1,135,987,605	1,151,960,125	1,199,075,596	981,057,514	925,240,008	814,993,534
CWIP Expenditures	109,552,914	161,232,037	162,661,776	132,258,844	168,860,438	171,028,613	153,117,819	141,801,066	162,800,539	140,560,345	125,801,212	168,171,288	1,797,846,892
AFUDC Debt	1,112,892	1,215,032	1,273,890	1,219,034	1,281,024	1,367,527	1,455,501	1,542,871	1,574,318	1,455,256	1,243,507	1,097,703	15,838,555
AFUDC Equity	2,640,735	2,883,098	3,022,761	2,892,596	3,039,689	3,244,947	3,453,697	3,661,014	3,735,633	3,453,116	2,950,665	2,604,694	37,582,644
Closings to Plant	(59,972,784)	(69,925,273)	(224,524,718)	(111,123,513)	(104,875,150)	(125,482,312)	(71,917,044)	(131,032,431)	(120,995,020)	(363,486,798)	(185,812,890)	(354,626,722)	(1,923,774,655)
CWIP Ending Balance	868,327,292	963,732,186	906,165,895	931,412,855	999,718,856	1,049,877,631	1,135,987,605	1,151,960,125	1,199,075,596	981,057,514	925,240,008	742,486,971	742,486,971
2024													
CWIP Beginning Balance	742,486,971	811,879,012	880,037,713	950,719,195	1,038,997,570	1,130,321,045	1,176,481,669	1,269,129,239	1,362,044,040	1,355,331,039	1,137,430,599	1,149,659,342	742,486,971
CWIP Expenditures	122,130,923	111,814,165	156,216,020	133,178,642	138,614,009	154,593,137	146,786,175	142,978,091	162,625,520	170,827,029	106,924,033	200,941,711	1,747,629,456
AFUDC Debt	1,043,734	1,136,984	1,242,726	1,355,109	1,482,889	1,587,700	1,683,414	1,815,196	1,907,534	1,717,912	1,572,702	1,577,297	18,123,195
AFUDC Equity	2,433,056	2,650,432	2,896,929	3,158,905	3,456,775	3,701,101	3,924,220	4,231,417	4,446,667	4,004,638	3,666,138	3,676,850	42,247,129
Closings to Plant	(56,215,671)	(47,442,881)	(89,674,194)	(49,414,280)	(52,230,198)	(113,721,314)	(59,746,238)	(56,109,903)	(175,692,722)	(394,450,019)	(99,934,130)	(267,067,973)	(1,461,699,524)
CWIP Ending Balance	811,879,012	880,037,713	950,719,195	1,038,997,570	1,130,321,045	1,176,481,669	1,269,129,239	1,362,044,040	1,355,331,039	1,137,430,599	1,149,659,342	1,088,787,227	1,088,787,227

Northern States Power Company
CWIP by Witness

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 2 of 49

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Benson													
CWIP Beginning Balance	71,930,294	85,494,816	96,348,650	108,898,603	119,485,871	114,141,140	124,807,209	131,521,439	150,846,574	161,073,800	168,355,605	179,250,427	71,930,294
CWIP Expenditures	14,070,351	12,227,556	22,733,562	14,223,688	14,142,263	21,070,661	20,191,624	23,643,420	29,779,458	18,976,866	17,531,721	18,192,722	226,783,893
AFUDC Debt	110,772	163,325	167,099	160,540	189,392	194,171	207,474	229,422	254,402	267,938	283,703	176,117	2,404,354
AFUDC Equity	258,649	394,618	398,648	393,548	451,679	463,051	494,775	547,115	606,686	638,966	676,563	419,997	5,744,294
Closings to Plant	(875,250)	(1,931,666)	(10,749,355)	(4,190,508)	(20,128,065)	(11,061,814)	(14,179,643)	(5,094,822)	(20,413,319)	(12,601,965)	(7,597,165)	(164,094,450)	(272,918,021)
CWIP Ending Balance	85,494,816	96,348,650	108,898,603	119,485,871	114,141,140	124,807,209	131,521,439	150,846,574	161,073,800	168,355,605	179,250,427	33,944,813	33,944,813
Bloch													
CWIP Beginning Balance	57,808,470	63,163,088	67,550,851	72,035,868	65,436,105	69,039,284	77,117,129	86,849,446	94,878,371	98,807,169	103,433,379	109,669,389	57,808,470
CWIP Expenditures	19,093,827	17,629,776	16,403,366	19,090,773	23,180,376	24,457,895	28,019,099	28,855,359	26,552,648	26,545,260	26,573,729	36,029,538	292,431,646
AFUDC Debt	86,579	113,867	102,840	104,929	101,013	97,836	112,863	116,631	119,502	123,302	129,563	87,314	1,296,239
AFUDC Equity	201,780	276,486	245,953	250,344	240,936	233,321	269,152	278,135	284,983	294,045	308,977	208,224	3,092,336
Closings to Plant	(14,027,568)	(13,632,366)	(12,267,143)	(26,045,810)	(19,919,145)	(16,711,207)	(18,668,798)	(21,221,199)	(23,028,335)	(22,336,397)	(20,776,259)	(80,706,388)	(289,340,614)
CWIP Ending Balance	63,163,088	67,550,851	72,035,868	65,436,105	69,039,284	77,117,129	86,849,446	94,878,371	98,807,169	103,433,379	109,669,389	65,288,076	65,288,076
Capra													
CWIP Beginning Balance	809,330,477	479,770,951	523,847,806	528,946,029	540,767,699	270,267,240	324,382,442	383,889,264	416,777,999	480,045,925	484,310,283	531,517,876	809,330,477
CWIP Expenditures	20,095,674	49,281,519	239,275,388	17,595,076	66,475,621	71,007,528	65,634,795	43,324,187	79,964,732	19,451,168	53,223,076	21,944,069	747,272,833
AFUDC Debt	874,879	926,252	840,283	841,140	646,416	481,708	575,666	654,611	733,522	788,663	829,607	551,459	8,744,205
AFUDC Equity	2,042,906	2,250,080	2,004,529	2,006,615	1,541,361	1,148,755	1,372,822	1,561,088	1,749,272	1,880,768	1,978,410	1,315,095	20,851,701
Closings to Plant	(352,572,986)	(8,380,996)	(237,021,977)	(8,621,161)	(339,163,858)	(18,522,789)	(8,076,461)	(12,651,150)	(19,179,600)	(17,856,241)	(8,823,499)	(413,279,179)	(1,444,149,897)
CWIP Ending Balance	479,770,951	523,847,806	528,946,029	540,767,699	270,267,240	324,382,442	383,889,264	416,777,999	480,045,925	484,310,283	531,517,876	142,049,319	142,049,319
Gardner													
CWIP Beginning Balance	195,719,404	200,882,157	209,273,936	215,976,108	225,193,711	210,734,367	220,283,555	231,681,497	239,748,846	158,447,576	162,496,323	158,731,986	195,719,404
CWIP Expenditures	6,766,397	7,431,526	79,943,964	18,292,153	10,264,475	14,019,617	16,308,628	11,898,299	13,892,417	13,626,484	7,695,221	23,396,662	223,535,843
AFUDC Debt	273,069	365,616	370,380	349,935	348,782	341,296	364,298	379,437	344,962	254,200	255,289	265,628	3,912,891
AFUDC Equity	637,609	884,598	883,509	834,818	831,679	813,911	868,762	904,864	822,651	606,204	608,801	633,457	9,330,863
Closings to Plant	(2,514,322)	(289,961)	(74,495,681)	(10,259,304)	(25,904,280)	(5,625,636)	(6,143,747)	(5,115,250)	(96,361,300)	(10,438,141)	(12,323,647)	(13,101,379)	(262,572,647)
CWIP Ending Balance	200,882,157	209,273,936	215,976,108	225,193,711	210,734,367	220,283,555	231,681,497	239,748,846	158,447,576	162,496,323	158,731,986	169,926,354	169,926,354
Husen													
CWIP Beginning Balance	2,616,189	2,840,433	3,759,774	5,141,804	6,772,860	7,448,436	6,856,959	903,626	931,907	1,103,184	924,324	897,504	2,616,189
CWIP Expenditures	769,283	1,564,260	1,699,343	1,657,309	1,470,357	1,141,955	1,133,079	1,898,245	2,828,719	3,051,587	1,719,262	4,149,047	23,082,446
Closings to Plant	(545,038)	(644,919)	(317,313)	(26,253)	(794,782)	(1,733,431)	(7,086,412)	(1,869,964)	(2,657,443)	(3,230,447)	(1,746,081)	(3,746,863)	(24,398,946)
CWIP Ending Balance	2,840,433	3,759,774	5,141,804	6,772,860	7,448,436	6,856,959	903,626	931,907	1,103,184	924,324	897,504	1,299,689	1,299,689
Moeller													
CWIP Beginning Balance	9,520,891	11,250,263	12,011,826	10,765,820	12,523,088	14,253,821	14,873,317	17,214,898	22,866,475	32,248,110	41,404,666	49,695,388	9,520,891
CWIP Expenditures	1,974,151	751,443	(380,973)	1,732,360	1,706,806	1,781,532	5,113,948	5,980,074	9,809,344	9,797,882	10,436,960	17,774,594	66,478,124
AFUDC Debt	8,096	10,978	10,119	10,597	12,577	15,765	21,682	28,284	36,897	48,632	62,654	73,121	339,402
AFUDC Equity	18,905	26,557	24,139	25,280	29,991	37,597	51,707	67,450	87,989	115,975	149,413	174,375	809,379
Closings to Plant	(271,781)	(27,415)	(899,290)	(10,970)	(18,643)	(1,215,398)	(2,845,756)	(424,231)	(552,595)	(805,934)	(2,358,305)	(20,167,875)	(29,598,193)
CWIP Ending Balance	11,250,263	12,011,826	10,765,820	12,523,088	14,253,821	14,873,317	17,214,898	22,866,475	32,248,110	41,404,666	49,695,388	47,549,603	47,549,603
Remington													
CWIP Beginning Balance	135,745,560	145,934,894	153,100,850	160,644,922	120,503,299	130,194,845	139,430,315	143,527,629	155,935,295	161,134,121	171,499,734	168,873,895	135,745,560
CWIP Expenditures	12,942,708	13,758,344	11,430,951	9,553,766	11,758,408	11,246,673	16,511,291	16,569,874	22,431,828	13,732,568	9,265,221	14,417,617	163,619,247
AFUDC Debt	169,708	235,218	220,629	214,768	166,837	179,350	178,901	186,631	196,253	204,437	209,770	150,244	2,312,747
AFUDC Equity	396,263	568,763	526,310	512,310	397,817	427,706	426,635	445,070	468,015	487,532	500,251	358,296	5,514,968
Closings to Plant	(3,319,344)	(7,396,369)	(4,633,818)	(50,422,466)	(2,631,516)	(2,618,260)	(13,019,513)	(4,793,909)	(17,897,269)	(4,058,925)	(12,601,081)	(124,967,311)	(248,359,781)
CWIP Ending Balance	145,934,894	153,100,850	160,644,922	120,503,299	130,194,845	139,430,315	143,527,629	155,935,295	161,134,121	171,499,734	168,873,895	58,832,740	58,832,740

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Benson													
CWIP Beginning Balance	33,944,813	52,492,101	63,438,895	72,315,195	90,323,423	92,679,316	88,685,508	110,214,993	125,202,599	140,881,698	165,549,787	188,714,276	33,944,813
CWIP Expenditures	21,034,218	20,156,959	27,407,775	20,392,855	18,639,644	25,363,173	22,800,086	20,051,624	32,354,422	29,274,630	25,897,600	36,989,187	300,362,173
AFUDC Debt	62,747	85,468	101,501	119,018	135,337	135,055	145,396	176,071	201,511	228,446	264,795	215,891	1,871,236
AFUDC Equity	151,874	206,867	245,674	288,073	327,569	326,887	351,917	426,164	487,738	552,931	640,911	522,542	4,529,146
Closings to Plant	(2,701,552)	(9,502,500)	(18,878,650)	(2,791,718)	(16,746,656)	(29,818,923)	(1,767,913)	(5,666,253)	(17,364,573)	(5,387,917)	(3,638,816)	(136,083,255)	(250,348,728)
CWIP Ending Balance	52,492,101	63,438,895	72,315,195	90,323,423	92,679,316	88,685,508	110,214,993	125,202,599	140,881,698	165,549,787	188,714,276	90,358,641	90,358,641
Bloch													
CWIP Beginning Balance	65,288,076	69,818,557	79,732,387	88,813,630	97,891,678	106,379,694	109,188,777	118,784,556	127,577,226	134,442,154	122,898,718	124,900,443	65,288,076
CWIP Expenditures	40,867,455	40,973,113	41,291,571	42,466,930	42,408,286	43,501,697	45,734,533	45,670,276	44,406,383	39,720,564	39,265,874	42,738,660	509,045,343
AFUDC Debt	49,068	65,031	78,363	91,201	103,321	111,021	118,120	129,391	138,859	134,324	126,347	112,050	1,257,095
AFUDC Equity	118,764	157,402	189,669	220,743	250,077	268,715	285,898	313,179	336,095	325,118	305,809	271,207	3,042,675
Closings to Plant	(36,504,807)	(31,281,715)	(32,478,359)	(33,700,825)	(34,273,667)	(41,072,350)	(36,542,771)	(37,320,177)	(38,016,409)	(51,723,442)	(37,696,305)	(62,218,098)	(472,828,926)
CWIP Ending Balance	69,818,557	79,732,387	88,813,630	97,891,678	106,379,694	109,188,777	118,784,556	127,577,226	134,442,154	122,898,718	124,900,443	105,804,263	105,804,263
Capra													
CWIP Beginning Balance	142,049,319	214,739,263	221,846,882	228,125,513	280,006,290	338,411,594	401,761,285	490,433,945	554,203,971	610,504,176	630,326,304	667,907,185	142,049,319
CWIP Expenditures	75,200,124	7,048,298	7,801,716	56,668,930	61,397,316	65,485,807	88,550,579	63,011,742	61,742,025	45,963,248	47,517,239	63,151,380	643,538,403
AFUDC Debt	271,951	333,175	344,363	388,204	472,644	565,942	682,524	799,444	892,054	951,224	994,229	740,797	7,436,552
AFUDC Equity	658,230	806,418	833,497	939,611	1,143,989	1,369,808	1,651,983	1,934,977	2,159,130	2,302,345	2,406,436	1,793,028	17,999,452
Closings to Plant	(3,440,362)	(1,080,271)	(2,700,946)	(6,115,968)	(4,608,646)	(4,071,866)	(2,212,427)	(1,976,138)	(8,493,003)	(29,394,688)	(13,337,024)	(460,450,301)	(537,881,638)
CWIP Ending Balance	214,739,263	221,846,882	228,125,513	280,006,290	338,411,594	401,761,285	490,433,945	554,203,971	610,504,176	630,326,304	667,907,185	273,142,088	273,142,088
Gardner													
CWIP Beginning Balance	169,926,354	186,008,707	193,665,491	199,645,715	205,708,891	210,602,764	225,609,237	213,857,227	225,095,600	155,997,581	170,521,670	175,544,386	169,926,354
CWIP Expenditures	15,234,096	8,576,160	6,348,508	6,119,536	14,982,228	15,045,154	12,963,729	15,660,561	11,293,833	22,306,594	15,239,208	76,174,982	219,944,591
AFUDC Debt	270,353	288,194	298,491	307,921	316,341	330,233	331,755	332,339	288,919	246,532	258,738	306,066	3,575,881
AFUDC Equity	654,362	697,545	722,467	745,293	765,673	799,296	802,980	804,393	699,300	596,707	626,251	740,802	8,655,072
Closings to Plant	(76,459)	(1,905,115)	(1,389,242)	(1,109,575)	(11,170,369)	(1,168,211)	(25,850,473)	(5,558,920)	(81,380,070)	(8,625,745)	(11,101,482)	(25,001,483)	(174,337,144)
CWIP Ending Balance	186,008,707	193,665,491	199,645,715	205,708,891	210,602,764	225,609,237	213,857,227	225,095,600	155,997,581	170,521,670	175,544,386	227,764,753	227,764,753
Husen													
CWIP Beginning Balance	1,299,689	947,689	737,677	783,279	771,823	821,897	933,960	889,147	1,120,759	999,389	824,804	695,743	1,299,689
CWIP Expenditures	527,644	866,707	3,951,360	4,358,539	4,414,201	4,134,379	3,053,663	4,137,463	2,070,640	2,012,941	1,624,147	434,887	31,586,571
Closings to Plant	(879,644)	(1,076,719)	(3,905,757)	(4,369,995)	(4,364,127)	(4,022,315)	(3,098,477)	(3,905,851)	(2,192,010)	(2,187,526)	(1,753,208)	(588,520)	(32,344,149)
CWIP Ending Balance	947,689	737,677	783,279	771,823	821,897	933,960	889,147	1,120,759	999,389	824,804	695,743	542,110	542,110
Moeller													
CWIP Beginning Balance	47,549,603	53,673,027	59,983,006	65,356,788	71,504,733	80,599,666	81,410,097	90,522,794	64,981,460	74,471,060	79,977,783	84,229,408	47,549,603
CWIP Expenditures	6,469,737	6,478,287	5,657,907	6,321,451	9,199,483	8,770,272	9,854,745	10,371,046	10,130,591	9,079,241	8,390,897	7,190,035	97,913,688
AFUDC Debt	74,162	83,861	92,770	101,472	113,182	120,863	127,889	114,716	100,810	111,519	118,703	72,082	1,232,030
AFUDC Equity	179,502	202,977	224,540	245,604	273,946	292,536	309,543	277,659	244,002	269,921	287,310	174,467	2,982,008
Closings to Plant	(599,976)	(455,145)	(601,435)	(520,582)	(491,677)	(8,373,240)	(1,179,480)	(36,304,755)	(985,804)	(3,953,958)	(4,545,285)	(75,695,289)	(133,706,624)
CWIP Ending Balance	53,673,027	59,983,006	65,356,788	71,504,733	80,599,666	81,410,097	90,522,794	64,981,460	74,471,060	79,977,783	84,229,408	15,970,704	15,970,704
Remington													
CWIP Beginning Balance	58,832,740	70,089,417	85,710,384	90,519,891	96,748,503	109,894,227	116,285,716	126,846,538	135,440,341	141,218,750	152,537,536	162,100,380	58,832,740
CWIP Expenditures	12,024,366	15,361,919	18,458,051	12,662,584	13,851,872	15,231,031	11,970,242	12,142,485	13,941,779	12,187,256	11,660,430	13,962,257	163,454,273
AFUDC Debt	81,988	92,276	100,835	107,186	115,366	124,842	133,418	142,416	150,918	159,846	167,801	147,786	1,524,676
AFUDC Equity	198,445	223,344	244,061	259,433	279,232	302,167	322,924	344,703	365,281	386,892	406,146	357,701	3,690,331
Closings to Plant	(1,048,122)	(56,572)	(13,993,441)	(6,800,591)	(1,100,746)	(9,266,551)	(1,865,762)	(4,035,801)	(8,679,569)	(1,415,208)	(2,671,533)	(75,157,149)	(126,091,045)
CWIP Ending Balance	70,089,417	85,710,384	90,519,891	96,748,503	109,894,227	116,285,716	126,846,538	135,440,341	141,218,750	152,537,536	162,100,380	101,410,975	101,410,975

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

Northern States Power Company
CWIP by Witness

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 4 of 49

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Benson													
CWIP Beginning Balance	90,358,641	105,043,853	107,997,515	103,293,737	115,737,232	130,339,712	112,890,399	127,005,807	143,551,151	146,695,684	167,605,598	188,165,673	90,358,641
CWIP Expenditures	20,944,726	12,046,033	39,955,704	14,535,772	21,165,033	40,231,813	20,097,076	17,484,319	43,707,488	22,738,693	22,431,008	42,684,930	318,022,595
AFUDC Debt	136,590	149,544	152,294	152,965	172,417	176,004	166,930	188,603	208,587	219,080	249,317	221,447	2,193,779
AFUDC Equity	324,109	354,847	361,371	362,963	409,120	417,633	396,102	447,529	494,947	519,845	591,594	525,463	5,205,524
Closings to Plant	(6,720,213)	(9,596,763)	(45,173,147)	(2,608,205)	(7,144,090)	(58,274,764)	(6,544,701)	(1,575,106)	(41,266,489)	(2,567,704)	(2,711,843)	(117,031,241)	(301,214,267)
CWIP Ending Balance	105,043,853	107,997,515	103,293,737	115,737,232	130,339,712	112,890,399	127,005,807	143,551,151	146,695,684	167,605,598	188,165,673	114,566,272	114,566,272
Bloch													
CWIP Beginning Balance	105,804,263	109,530,162	113,661,839	118,862,841	117,601,150	124,557,193	123,427,303	131,846,793	132,209,088	138,801,954	129,828,605	131,362,180	105,804,263
CWIP Expenditures	44,255,077	43,459,149	44,095,600	45,076,722	45,398,425	46,607,081	48,207,826	48,128,480	47,282,307	44,410,907	38,303,004	45,362,695	540,587,271
AFUDC Debt	92,621	96,454	101,469	102,567	104,540	107,113	109,121	111,928	113,818	110,993	104,295	105,426	1,260,344
AFUDC Equity	219,777	228,872	240,770	243,376	248,059	254,163	258,929	265,589	270,075	263,370	247,476	250,161	2,990,619
Closings to Plant	(40,841,575)	(39,652,799)	(39,236,837)	(46,684,355)	(38,794,982)	(48,098,247)	(40,156,385)	(48,143,702)	(41,073,333)	(53,758,618)	(37,121,200)	(44,070,014)	(517,632,048)
CWIP Ending Balance	109,530,162	113,661,839	118,862,841	117,601,150	124,557,193	123,427,303	131,846,793	132,209,088	138,801,954	129,828,605	131,362,180	133,010,448	133,010,448
Capra													
CWIP Beginning Balance	273,142,088	295,726,829	314,037,032	332,339,092	354,105,094	404,703,256	449,406,529	500,075,117	541,051,069	579,168,977	334,979,343	240,398,428	273,142,088
CWIP Expenditures	22,419,814	19,422,624	30,087,202	38,549,969	57,769,593	44,691,353	49,130,549	39,600,275	37,674,027	37,960,854	35,956,516	37,715,024	450,977,801
AFUDC Debt	413,868	443,635	470,974	500,119	552,343	621,380	690,746	757,387	815,110	671,266	419,440	361,321	6,717,589
AFUDC Equity	982,051	1,052,683	1,117,553	1,186,710	1,310,631	1,474,447	1,639,041	1,797,172	1,934,140	1,592,819	995,272	857,364	15,939,884
Closings to Plant	(1,230,993)	(2,608,738)	(13,373,669)	(18,470,797)	(9,034,404)	(2,083,909)	(791,748)	(1,178,882)	(2,305,370)	(284,414,573)	(131,952,142)	(23,077,798)	(490,523,022)
CWIP Ending Balance	295,726,829	314,037,032	332,339,092	354,105,094	404,703,256	449,406,529	500,075,117	541,051,069	579,168,977	334,979,343	240,398,428	256,254,340	256,254,340
Gardner													
CWIP Beginning Balance	227,764,753	231,988,080	304,401,474	229,117,211	235,387,989	219,056,071	230,264,319	224,652,893	161,967,799	174,130,090	180,925,892	181,906,398	227,764,753
CWIP Expenditures	11,306,370	71,274,222	26,335,261	15,205,553	21,077,218	14,928,518	10,244,717	12,101,826	13,811,432	15,383,797	7,624,548	22,382,050	241,675,513
AFUDC Debt	333,688	389,373	414,402	336,997	331,458	325,830	329,726	302,357	242,566	257,513	262,143	250,895	3,776,947
AFUDC Equity	791,793	923,926	983,317	799,646	786,502	773,148	782,394	717,451	575,574	611,042	622,027	595,338	8,962,158
Closings to Plant	(8,208,524)	(174,128)	(103,017,242)	(10,071,417)	(38,527,096)	(4,819,248)	(16,968,263)	(75,806,728)	(2,467,281)	(9,456,550)	(7,528,213)	(40,444,639)	(317,489,329)
CWIP Ending Balance	231,988,080	304,401,474	229,117,211	235,387,989	219,056,071	230,264,319	224,652,893	161,967,799	174,130,090	180,925,892	181,906,398	164,690,042	164,690,042
Husen													
CWIP Beginning Balance	542,110	435,779	412,897	606,792	824,952	1,073,790	1,222,070	1,324,803	1,065,407	926,136	730,208	780,330	542,110
CWIP Expenditures	632,000	1,084,000	5,747,667	4,286,000	4,483,000	4,242,000	5,008,879	1,780,617	1,954,367	1,886,098	3,117,667	372,667	34,594,960
Closings to Plant	(738,331)	(1,106,882)	(5,553,772)	(4,067,840)	(4,234,162)	(4,093,719)	(4,906,147)	(2,040,012)	(2,093,638)	(2,082,025)	(3,067,544)	(529,677)	(34,513,750)
CWIP Ending Balance	435,779	412,897	606,792	824,952	1,073,790	1,222,070	1,324,803	1,065,407	926,136	730,208	780,330	623,320	623,320
Moeller													
CWIP Beginning Balance	15,970,704	16,129,350	16,927,341	18,248,377	19,532,855	26,637,054	35,595,143	45,067,144	56,613,305	64,428,399	72,218,625	78,646,825	15,970,704
CWIP Expenditures	813,773	1,296,423	1,715,623	1,604,084	7,386,020	9,239,837	9,664,500	11,626,013	7,822,422	7,732,050	7,445,523	6,588,979	72,935,247
AFUDC Debt	18,212	19,702	21,837	24,184	30,680	42,666	56,273	71,732	85,896	97,298	107,745	87,044	663,268
AFUDC Equity	43,214	46,750	51,817	57,385	72,800	101,240	133,528	170,209	203,818	230,875	255,665	206,542	1,573,841
Closings to Plant	(716,552)	(564,883)	(468,241)	(401,174)	(385,301)	(425,655)	(382,299)	(321,793)	(297,041)	(269,997)	(1,380,734)	(44,497,811)	(50,111,482)
CWIP Ending Balance	16,129,350	16,927,341	18,248,377	19,532,855	26,637,054	35,595,143	45,067,144	56,613,305	64,428,399	72,218,625	78,646,825	41,031,578	41,031,578
Remington													
CWIP Beginning Balance	101,410,975	109,473,239	106,294,089	103,697,845	88,223,583	93,351,780	97,071,868	106,015,048	115,502,306	94,924,356	94,769,242	103,980,173	101,410,975
CWIP Expenditures	9,181,154	12,649,585	14,724,719	13,000,744	11,581,149	11,088,010	10,764,273	11,079,537	10,548,497	10,447,947	10,922,947	13,064,944	139,053,506
AFUDC Debt	117,913	116,324	112,915	102,204	89,587	94,534	102,705	110,864	108,342	99,106	100,567	71,570	1,226,629
AFUDC Equity	279,791	276,020	267,932	242,515	212,576	224,315	243,703	263,064	257,079	235,164	238,631	169,825	2,910,617
Closings to Plant	(1,516,595)	(16,221,080)	(17,701,810)	(28,819,725)	(6,755,115)	(7,686,770)	(2,167,501)	(1,966,207)	(31,491,867)	(10,937,330)	(2,051,214)	(84,975,541)	(212,290,757)
CWIP Ending Balance	109,473,239	106,294,089	103,697,845	88,223,583	93,351,780	97,071,868	106,015,048	115,502,306	94,924,356	94,769,242	103,980,173	32,310,971	32,310,971

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Benson													
CWIP Beginning Balance	114,566,272	132,080,407	144,521,012	150,393,614	170,586,173	187,040,198	175,955,495	202,335,914	218,831,568	220,071,242	250,049,533	271,133,691	114,566,272
CWIP Expenditures	23,262,644	13,056,492	36,427,781	20,445,396	16,617,557	37,683,029	27,089,521	17,006,911	46,637,646	30,316,080	21,139,998	46,379,039	336,062,094
AFUDC Debt	178,541	198,515	216,054	230,685	257,494	265,461	272,070	303,394	321,887	339,075	376,595	361,757	3,321,528
AFUDC Equity	416,198	462,760	503,646	537,751	600,246	618,819	634,224	707,245	750,354	790,420	877,883	843,295	7,742,842
Closings to Plant	(6,343,248)	(1,277,162)	(31,274,880)	(1,021,272)	(1,021,272)	(49,652,011)	(1,615,396)	(1,521,896)	(46,470,214)	(1,467,284)	(1,310,318)	(101,045,129)	(244,020,083)
CWIP Ending Balance	132,080,407	144,521,012	150,393,614	170,586,173	187,040,198	175,955,495	202,335,914	218,831,568	220,071,242	250,049,533	271,133,691	217,672,653	217,672,653
Bloch													
CWIP Beginning Balance	133,010,448	137,582,487	142,316,768	147,301,432	152,022,692	157,540,071	156,666,203	164,820,655	171,748,002	177,473,738	135,654,217	110,031,595	133,010,448
CWIP Expenditures	44,327,889	44,142,179	44,343,027	44,381,007	44,863,784	45,761,662	49,154,325	48,526,751	43,289,403	39,166,405	35,450,612	51,698,626	535,105,670
AFUDC Debt	110,044	114,953	120,199	126,234	133,458	136,959	140,316	149,014	156,899	130,829	100,109	101,585	1,520,599
AFUDC Equity	256,526	267,967	280,196	294,266	311,106	319,266	327,091	347,368	365,748	304,975	233,366	236,806	3,544,680
Closings to Plant	(40,122,420)	(39,790,818)	(39,758,758)	(40,080,248)	(39,790,969)	(47,091,755)	(41,467,279)	(42,095,786)	(38,086,314)	(81,421,730)	(61,406,709)	(54,395,834)	(565,508,620)
CWIP Ending Balance	137,582,487	142,316,768	147,301,432	152,022,692	157,540,071	156,666,203	164,820,655	171,748,002	177,473,738	135,654,217	110,031,595	107,672,778	107,672,778
Capra													
CWIP Beginning Balance	256,254,340	287,401,987	316,970,580	365,556,610	415,313,528	462,325,236	504,112,491	537,384,863	590,917,189	631,726,916	411,998,040	421,443,450	256,254,340
CWIP Expenditures	30,869,086	31,195,783	51,810,977	49,394,609	47,963,472	43,521,751	40,467,415	52,664,492	42,671,449	76,401,478	31,292,576	32,906,424	531,159,511
AFUDC Debt	405,783	451,169	509,940	583,004	655,410	721,564	778,025	842,510	913,215	785,102	622,619	645,395	7,913,736
AFUDC Equity	945,925	1,051,725	1,188,726	1,359,044	1,527,832	1,682,044	1,813,660	1,963,982	2,128,802	1,830,157	1,451,393	1,504,486	18,447,775
Closings to Plant	(1,073,147)	(3,130,085)	(4,923,613)	(1,579,738)	(3,135,006)	(4,138,104)	(9,786,728)	(1,938,658)	(4,903,738)	(298,745,612)	(23,921,178)	(14,240,108)	(371,515,716)
CWIP Ending Balance	287,401,987	316,970,580	365,556,610	415,313,528	462,325,236	504,112,491	537,384,863	590,917,189	631,726,916	411,998,040	421,443,450	442,259,647	442,259,647
Gardner													
CWIP Beginning Balance	164,690,042	168,777,240	176,387,098	187,884,568	193,854,576	207,622,049	220,279,649	237,152,932	245,060,781	188,798,008	195,583,500	196,200,156	164,690,042
CWIP Expenditures	3,286,542	6,776,609	11,592,031	5,136,369	12,942,056	11,981,413	16,135,909	10,577,845	18,371,862	13,747,756	8,468,331	60,486,358	179,503,082
AFUDC Debt	246,758	255,396	269,514	282,057	296,185	315,122	336,377	356,372	344,752	285,931	290,835	312,825	3,592,125
AFUDC Equity	575,218	595,357	628,267	657,506	690,438	734,584	784,130	830,742	803,655	666,536	677,969	729,229	8,373,632
Closings to Plant	(21,320)	(17,504)	(992,343)	(105,924)	(161,206)	(373,520)	(383,133)	(3,857,110)	(75,783,043)	(7,914,731)	(8,820,479)	(33,580,504)	(132,010,816)
CWIP Ending Balance	168,777,240	176,387,098	187,884,568	193,854,576	207,622,049	220,279,649	237,152,932	245,060,781	188,798,008	195,583,500	196,200,156	224,148,065	224,148,065
Husen													
CWIP Beginning Balance	623,320	572,365	506,887	519,369	739,494	1,049,323	1,226,909	1,332,424	1,280,807	1,183,655	1,020,303	865,412	623,320
CWIP Expenditures	677,846	962,769	2,818,897	4,421,845	5,238,845	4,283,845	3,803,076	3,822,462	1,905,544	1,851,515	1,449,615	399,623	31,635,882
Closings to Plant	(728,801)	(1,028,248)	(2,806,414)	(4,201,719)	(4,929,016)	(4,106,259)	(3,697,562)	(3,874,079)	(2,002,696)	(2,014,867)	(1,604,506)	(584,557)	(31,578,723)
CWIP Ending Balance	572,365	506,887	519,369	739,494	1,049,323	1,226,909	1,332,424	1,280,807	1,183,655	1,020,303	865,412	680,479	680,479
Moeller													
CWIP Beginning Balance	41,031,578	48,816,952	56,681,559	58,031,453	59,812,090	63,167,272	66,623,144	69,104,088	71,545,772	73,538,060	75,033,447	76,104,488	41,031,578
CWIP Expenditures	7,750,773	7,752,773	1,208,773	1,673,616	3,307,869	3,494,287	2,582,273	2,534,975	2,089,961	1,554,140	1,099,246	945,994	35,994,680
AFUDC Debt	65,151	76,930	83,857	86,247	90,151	95,268	99,719	103,397	106,656	109,197	111,110	100,685	1,128,368
AFUDC Equity	151,875	179,332	195,479	201,050	210,152	222,080	232,457	241,031	248,626	254,549	259,009	234,708	2,630,348
Closings to Plant	(182,425)	(144,428)	(138,214)	(180,275)	(252,990)	(355,763)	(433,506)	(437,719)	(452,955)	(422,498)	(398,324)	(16,607,183)	(20,006,282)
CWIP Ending Balance	48,816,952	56,681,559	58,031,453	59,812,090	63,167,272	66,623,144	69,104,088	71,545,772	73,538,060	75,033,447	76,104,488	60,778,693	60,778,693
Remington													
CWIP Beginning Balance	32,310,971	36,647,573	42,653,810	41,032,149	46,669,016	51,576,896	51,617,778	56,998,364	62,659,921	62,539,421	68,091,558	73,880,549	32,310,971
CWIP Expenditures	11,956,143	7,927,560	8,014,535	7,725,800	7,680,425	7,867,150	7,553,655	7,844,655	7,659,655	7,789,655	8,023,655	8,125,647	98,168,537
AFUDC Debt	37,456	40,021	43,162	46,882	50,191	53,326	56,908	60,507	64,125	67,779	71,433	55,049	646,839
AFUDC Equity	87,313	93,292	100,615	109,287	117,001	124,309	132,658	141,049	149,482	158,001	166,518	128,326	1,507,851
Closings to Plant	(7,744,309)	(2,054,637)	(9,779,972)	(2,245,103)	(2,939,738)	(8,003,902)	(2,362,634)	(2,384,655)	(7,993,762)	(2,463,298)	(2,472,616)	(46,614,658)	(97,059,284)
CWIP Ending Balance	36,647,573	42,653,810	41,032,149	46,669,016	51,576,896	51,617,778	56,998,364	62,659,921	62,539,421	68,091,558	73,880,549	35,574,913	35,574,913

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

Northern States Power Company
CWIP by Witness, Functional Class, and Category

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 6 of 49

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Benson													
Asset Renewal													
Electric General Plant													
CWIP Beginning Balance	401,961	701,197	1,008,785	1,417,411	1,726,648	1,394,185	948,307	1,441,299	1,875,823	1,893,655	2,448,922	3,041,705	401,961
CWIP Expenditures	298,027	324,944	5,595,538	306,086	250,659	320,309	497,636	434,440	541,430	557,840	687,040	719,750	10,533,699
AFUDC Debt	471	918	1,082	1,303	1,140	833	908	1,502	2,180	2,879	3,725	3,168	20,108
AFUDC Equity	1,101	2,211	2,580	3,108	2,718	1,986	2,166	3,582	5,198	6,867	8,882	7,554	47,953
Closings to Plant	(363)	(20,484)	(5,190,574)	(1,259)	(586,979)	(769,006)	(7,719)	(5,000)	(530,976)	(12,319)	(106,864)	(2,583,972)	(9,815,515)
CWIP Ending Balance	701,197	1,008,785	1,417,411	1,726,648	1,394,185	948,307	1,441,299	1,875,823	1,893,655	2,448,922	3,041,705	1,188,205	1,188,205
Electric Transmission Plant													
CWIP Beginning Balance	19,961,062	24,350,317	27,689,894	28,905,719	29,789,691	26,281,400	27,171,336	29,358,938	35,137,370	39,034,391	40,878,181	47,454,706	19,961,062
CWIP Expenditures	4,715,411	4,776,311	4,725,010	4,137,207	4,786,288	6,213,628	6,261,838	6,282,212	10,362,332	6,787,950	9,247,841	8,041,851	76,337,880
AFUDC Debt	31,662	47,343	47,154	48,133	46,458	44,177	45,333	52,569	61,947	68,183	76,396	58,397	627,751
AFUDC Equity	73,930	114,366	112,482	114,918	110,779	105,351	108,109	125,364	147,729	162,599	182,187	139,262	1,497,074
Closings to Plant	(431,748)	(1,598,443)	(3,668,821)	(3,416,285)	(8,451,817)	(5,473,220)	(4,227,678)	(681,712)	(6,674,987)	(5,174,941)	(2,929,898)	(35,253,103)	(77,982,655)
CWIP Ending Balance	24,350,317	27,689,894	28,905,719	29,789,691	26,281,400	27,171,336	29,358,938	35,137,370	39,034,391	40,878,181	47,454,706	20,441,113	20,441,113
Comm Infrastructure													
Electric General Plant													
CWIP Beginning Balance	228,069	463,615	359,729	439,158	558,634	735,234	849,403	1,165,852	1,715,313	2,441,657	3,002,246	1,811,758	228,069
CWIP Expenditures	234,658	79,424	77,393	116,549	175,714	110,323	314,597	820,155	724,848	550,522	480,503	403,470	4,088,157
AFUDC Debt	478	736	656	815	1,059	1,296	1,648	2,408	3,399	4,452	3,962	2,624	23,532
AFUDC Equity	1,116	1,776	1,564	1,945	2,524	3,090	3,930	5,744	8,106	10,616	9,449	6,257	56,117
Closings to Plant	(707)	(185,822)	(183)	167	(2,697)	(540)	(3,725)	(278,846)	(10,010)	(5,000)	(1,684,402)	(867,103)	(3,038,869)
CWIP Ending Balance	463,615	359,729	439,158	558,634	735,234	849,403	1,165,852	1,715,313	2,441,657	3,002,246	1,811,758	1,357,006	1,357,006
Electric Transmission Plant													
CWIP Beginning Balance	7,897	58,469	78,265	201,183	297,667	388,939	518,082	706,343	1,714,513	2,774,546	3,004,466	3,641,540	7,897
CWIP Expenditures	47,732	19,393	157,519	95,082	88,923	122,233	184,221	1,001,470	1,047,608	1,217,294	618,875	494,944	5,095,294
AFUDC Debt	47	118	229	408	562	742	1,002	1,980	3,671	4,788	5,435	3,570	22,551
AFUDC Equity	110	284	546	972	1,339	1,770	2,389	4,721	8,754	11,418	12,960	8,514	53,778
Closings to Plant	2,684	-	(35,375)	22	448	4,398	649	-	-	(1,003,580)	(196)	(3,643,056)	(4,674,006)
CWIP Ending Balance	58,469	78,265	201,183	297,667	388,939	518,082	706,343	1,714,513	2,774,546	3,004,466	3,641,540	505,513	505,513
Interconnection													
Electric General Plant													
CWIP Beginning Balance	87,779	89,149	91,810	113,221	129,099	157,211	245,992	238,820	395,576	824	829	833	87,779
CWIP Expenditures	3,637	2,552	23,092	16,076	27,465	87,665	87,000	155,000	55,000	40,000	20,000	10,000	527,486
AFUDC Debt	125	166	168	198	234	330	319	519	348	1	1	1	2,410
AFUDC Equity	293	402	401	472	559	786	760	1,237	829	3	3	2	5,747
Closings to Plant	(2,685)	(458)	(2,250)	(868)	(146)	-	(95,250)	-	(450,929)	(40,000)	(20,000)	(10,836)	(623,422)
CWIP Ending Balance	89,149	91,810	113,221	129,099	157,211	245,992	238,820	395,576	824	829	833	-	-
Electric Transmission Plant													
CWIP Beginning Balance	843,926	2,954,076	4,977,512	9,659,977	14,706,829	17,997,129	20,341,452	20,114,092	23,499,036	23,906,464	27,456,494	29,769,977	843,926
CWIP Expenditures	2,118,038	2,095,770	5,084,573	4,947,415	3,276,658	2,262,840	2,545,310	3,348,764	9,047,394	3,412,712	2,150,357	994,920	41,284,752
AFUDC Debt	3,879	8,532	13,385	(2,726)	27,936	32,720	34,820	37,382	42,180	43,465	48,194	26,061	315,827
AFUDC Equity	9,057	20,522	31,974	3,974	66,683	78,029	83,037	89,146	100,590	103,653	114,932	62,149	763,746
Closings to Plant	(20,825)	(101,387)	(447,468)	98,189	(80,976)	(29,267)	(2,890,527)	(90,348)	(8,782,736)	(9,800)	-	(30,878,545)	(43,233,691)
CWIP Ending Balance	2,954,076	4,977,512	9,659,977	14,706,829	17,997,129	20,341,452	20,114,092	23,499,036	23,906,464	27,456,494	29,769,977	(25,439)	(25,439)
Regional Expansion													
Electric General Plant													
CWIP Beginning Balance	-	-	800	57,183	70,848	98,525	99,072	100,625	102,186	103,756	105,335	120,961	-
CWIP Expenditures	-	798	56,222	13,311	27,208	-	1,000	1,000	1,000	1,000	15,000	1,000	117,539
AFUDC Debt	-	1	47	105	139	162	163	166	168	171	185	100	1,406
AFUDC Equity	-	2	113	250	330	385	389	396	402	408	441	238	3,353
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(122,298)	(122,298)
CWIP Ending Balance	-	800	57,183	70,848	98,525	99,072	100,625	102,186	103,756	105,335	120,961	-	-
Electric Transmission Plant													
CWIP Beginning Balance	34,912,372	37,334,066	38,932,409	41,413,807	42,777,350	44,825,243	47,306,110	49,166,842	51,260,645	52,976,713	54,248,141	55,509,620	34,912,372
CWIP Expenditures	2,249,925	1,361,535	2,259,439	1,124,282	1,806,243	2,061,173	1,705,237	1,829,838	1,543,558	1,005,649	967,690	661,504	18,576,073
AFUDC Debt	51,206	69,712	65,916	68,800	71,673	75,334	78,887	82,123	85,238	87,681	89,752	46,056	872,378
AFUDC Equity	119,565	168,625	157,241	164,127	170,907	179,654	188,126	195,842	203,272	209,098	214,037	109,833	2,080,327
Closings to Plant	998	(1,530)	(1,198)	6,336	(930)	164,705	(111,518)	(14,000)	(116,000)	(31,000)	(10,000)	(55,945,313)	(56,059,450)
CWIP Ending Balance	37,334,066	38,932,409	41,413,807	42,777,350	44,825,243	47,306,110	49,166,842	51,260,645	52,976,713	54,248,141	55,509,620	381,700	381,700

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Reliability Requirement													
Electric General Plant													
CWIP Beginning Balance	289,385	293,930	297,014	302,631	309,155	320,435	166,077	4,117	4,631	8,588	12,567	16,567	289,385
CWIP Expenditures	4,905	1,982	4,091	90,560	9,537	136,690	22,490	20,490	3,920	3,920	3,920	3,920	306,425
AFUDC Debt	413	543	492	500	515	445	6	7	11	17	24	30	3,004
AFUDC Equity	965	1,313	1,174	1,193	1,228	1,062	15	17	26	41	57	72	7,164
Closings to Plant	(1,739)	(754)	(140)	(85,729)	-	(292,555)	(184,471)	(20,000)	-	-	-	-	(585,388)
CWIP Ending Balance	293,930	297,014	302,631	309,155	320,435	166,077	4,117	4,631	8,588	12,567	16,567	20,590	20,590
Electric Transmission Plant													
CWIP Beginning Balance	12,494,718	14,959,535	16,957,837	19,568,807	21,743,787	15,990,917	20,632,034	22,775,506	27,139,299	28,029,810	26,143,545	25,983,314	12,494,718
CWIP Expenditures	2,534,500	1,932,654	2,943,126	2,303,547	2,493,729	7,958,179	7,165,143	8,193,243	4,574,379	3,765,711	2,548,555	1,627,106	48,039,871
AFUDC Debt	17,707	26,437	27,713	31,525	28,855	27,870	34,001	38,988	40,656	39,198	37,296	23,170	373,415
AFUDC Equity	41,344	63,865	66,105	75,205	68,806	66,463	81,083	92,976	96,954	93,479	88,943	55,254	890,477
Closings to Plant	(128,733)	(24,654)	(425,973)	(235,297)	(8,344,260)	(3,411,395)	(5,136,754)	(3,961,415)	(3,821,477)	(5,784,653)	(2,835,025)	(19,033,324)	(53,142,961)
CWIP Ending Balance	14,959,535	16,957,837	19,568,807	21,743,787	15,990,917	20,632,034	22,775,506	27,139,299	28,029,810	26,143,545	25,983,314	8,655,520	8,655,520
Security\Resiliency													
Electric General Plant													
CWIP Beginning Balance	936,050	766,602	867,653	1,256,653	1,457,168	1,625,239	1,792,726	1,389,814	1,717,412	1,910,722	2,021,914	2,211,338	936,050
CWIP Expenditures	75,260	97,539	449,941	193,534	158,490	242,538	270,570	338,128	194,898	158,388	178,818	136,928	2,495,033
AFUDC Debt	1,076	1,299	1,550	2,062	2,383	2,696	2,377	2,502	2,928	3,178	3,423	2,191	27,666
AFUDC Equity	2,511	3,149	3,696	4,919	5,683	6,430	5,669	5,967	6,983	7,579	8,163	5,225	65,975
Closings to Plant	(248,296)	(937)	(66,187)	-	1,514	(84,178)	(681,527)	(19,000)	(11,500)	(57,952)	(980)	(1,878,704)	(3,047,746)
CWIP Ending Balance	766,602	867,653	1,256,653	1,457,168	1,625,239	1,792,726	1,389,814	1,717,412	1,910,722	2,021,914	2,211,338	476,979	476,979
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	1,767,074	3,523,860	5,086,943	5,562,854	5,918,994	4,326,684	4,736,619	5,059,191	6,284,770	7,992,676	9,032,967	9,688,107	1,767,074
CWIP Expenditures	1,788,258	1,534,655	1,357,616	880,040	1,041,349	1,555,082	1,136,582	1,218,680	1,683,091	1,475,880	613,122	5,097,329	19,381,685
AFUDC Debt	3,707	7,521	8,708	9,417	8,439	7,566	8,010	9,277	11,676	13,924	15,309	10,750	114,305
AFUDC Equity	8,656	18,103	20,772	22,465	20,123	18,043	19,102	22,123	27,843	33,206	36,509	25,636	272,582
Closings to Plant	(43,836)	2,804	(911,185)	(555,783)	(2,662,221)	(1,170,755)	(841,122)	(24,500)	(14,704)	(482,719)	(9,800)	(13,878,197)	(20,592,020)
CWIP Ending Balance	3,523,860	5,086,943	5,562,854	5,918,994	4,326,684	4,736,619	5,059,191	6,284,770	7,992,676	9,032,967	9,688,107	943,626	943,626
Bloch													
AGIS													
Electric Distribution Plant													
CWIP Beginning Balance	571,238	598,512	570,183	642,572	712,574	806,737	884,724	1,033,932	1,334,657	1,635,381	1,606,545	4,145,053	571,238
CWIP Expenditures	24,538	(31,970)	70,749	66,265	89,968	73,318	147,770	300,725	300,725	722,016	2,693,101	3,761,144	8,218,349
AFUDC Debt	820	1,064	559	1,104	1,239	1,379	1,098	-	-	-	-	-	7,264
AFUDC Equity	1,915	2,576	1,334	2,633	2,955	3,290	2,617	-	-	-	-	-	17,320
Closings to Plant	-	-	(252)	-	-	-	(2,277)	-	-	(750,853)	(154,592)	(154,592)	(1,062,567)
CWIP Ending Balance	598,512	570,183	642,572	712,574	806,737	884,724	1,033,932	1,334,657	1,635,381	1,606,545	4,145,053	7,751,605	7,751,605
Electric General Plant													
CWIP Beginning Balance	1,428,857	1,562,734	1,572,614	1,777,194	2,333,187	3,267,019	443,010	314,407	324,596	331,220	335,525	338,323	1,428,857
CWIP Expenditures	128,597	78,512	196,961	546,309	926,915	1,081,445	614,528	226,144	435,371	447,611	716,506	252,926	5,651,824
AFUDC Debt	1,583	2,233	2,250	2,861	2,043	-	-	-	-	-	-	-	10,971
AFUDC Equity	3,697	5,399	5,368	6,824	4,873	-	-	-	-	-	-	-	26,160
Closings to Plant	-	(76,263)	(0)	(0)	-	(3,905,454)	(743,130)	(215,954)	(428,748)	(443,305)	(713,708)	(204,076)	(6,730,639)
CWIP Ending Balance	1,562,734	1,572,614	1,777,194	2,333,187	3,267,019	443,010	314,407	324,596	331,220	335,525	338,323	387,174	387,174
Electric Intangible Plant													
CWIP Beginning Balance	1,130,874	1,215,404	1,321,171	1,429,263	920,603	1,002,188	1,113,185	1,264,766	1,451,811	1,639,895	1,829,022	2,021,706	1,130,874
CWIP Expenditures	84,641	102,233	100,618	126,001	114,505	124,726	145,000	179,526	179,526	179,526	182,026	111,526	1,629,853
AFUDC Debt	1,663	2,313	2,256	1,945	1,574	1,730	1,945	2,221	2,528	2,837	3,149	3,278	27,439
AFUDC Equity	3,883	5,593	5,382	4,641	3,752	4,125	4,637	5,298	6,029	6,765	7,509	7,818	65,432
Closings to Plant	(5,657)	(4,372)	(165)	(641,247)	(38,245)	(19,584)	-	-	-	-	-	(174,606)	(883,875)
CWIP Ending Balance	1,215,404	1,321,171	1,429,263	920,603	1,002,188	1,113,185	1,264,766	1,451,811	1,639,895	1,829,022	2,021,706	1,969,723	1,969,723
Asset Health & Reliability													
Electric Distribution Plant													
CWIP Beginning Balance	14,940,187	15,581,450	15,374,087	15,459,023	14,758,189	17,749,496	17,458,169	19,765,157	22,176,747	23,412,495	24,185,231	24,997,335	14,940,187
CWIP Expenditures	9,167,060	6,544,936	8,458,550	9,109,680	10,219,191	11,190,871	12,335,486	11,969,938	11,897,633	10,998,361	10,507,749	21,855,503	134,254,957
AFUDC Debt	13,813	15,440	13,280	12,582	13,969	14,719	15,243	15,934	16,464	16,895	18,952	21,731	189,025
AFUDC Equity	31,874	37,262	31,682	30,017	33,311	35,107	36,351	37,999	39,262	40,291	45,197	51,823	450,177
Closings to Plant	(8,571,484)	(6,805,002)	(8,418,575)	(9,853,114)	(7,275,165)	(11,532,025)	(10,080,092)	(9,612,281)	(10,717,611)	(10,282,811)	(9,759,794)	(13,864,850)	(116,772,804)
CWIP Ending Balance	15,581,450	15,374,087	15,459,023	14,758,189	17,749,496	17,458,169	19,765,157	22,176,747	23,412,495	24,185,231	24,997,335	33,061,543	33,061,543

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Electric General Plant													
CWIP Beginning Balance	6,607	1,673	11,890	20,887	12,308	24,818	43,148	42,091	41,348	33,648	28,233	24,424	6,607
CWIP Expenditures	(1,726)	10,217	9,014	(8,578)	12,510	18,141	16,740	16,740	6,510	6,510	6,510	6,510	99,098
AFUDC Debt	-	-	-	-	-	56	72	70	62	51	44	39	394
AFUDC Equity	-	-	-	-	-	133	171	168	148	123	105	92	939
Closings to Plant	(3,208)	-	(17)	-	-	-	(18,039)	(17,721)	(14,421)	(12,100)	(10,467)	(9,319)	(85,292)
CWIP Ending Balance	1,673	11,890	20,887	12,308	24,818	43,148	42,091	41,348	33,648	28,233	24,424	21,745	21,745
Capacity													
Electric Distribution Plant													
CWIP Beginning Balance	29,318,096	31,371,881	33,684,223	37,168,508	32,956,122	28,906,465	27,617,392	27,098,111	27,408,901	30,000,439	33,120,748	34,484,796	29,318,096
CWIP Expenditures	4,108,326	2,484,617	3,585,684	2,135,369	2,049,410	3,003,186	1,758,503	2,054,509	3,034,147	3,525,589	2,308,380	2,209,348	32,257,069
AFUDC Debt	38,880	56,067	55,270	56,121	48,687	44,018	43,514	44,619	46,730	51,200	54,903	31,447	571,455
AFUDC Equity	90,783	136,120	131,843	133,257	116,093	104,972	103,769	106,406	111,441	122,098	130,930	74,994	1,362,706
Closings to Plant	(2,184,204)	(364,462)	(288,512)	(6,537,134)	(6,263,847)	(4,441,249)	(2,425,067)	(1,894,744)	(600,781)	(578,578)	(1,130,166)	(32,997,843)	(59,706,585)
CWIP Ending Balance	31,371,881	33,684,223	37,168,508	32,956,122	28,906,465	27,617,392	27,098,111	27,408,901	30,000,439	33,120,748	34,484,796	3,802,742	3,802,742
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicles													
Electric Distribution Plant													
CWIP Beginning Balance	85,393	87,068	89,090	95,064	188,291	198,799	251,971	1,072,891	1,496,916	1,639,189	2,041,656	2,406,599	85,393
CWIP Expenditures	1,268	1,469	5,469	92,464	9,476	52,107	1,279,708	1,064,764	844,223	1,277,068	1,396,065	1,643,595	7,667,675
AFUDC Debt	122	162	149	225	305	315	302	235	165	116	82	184	2,363
AFUDC Equity	285	391	356	537	728	750	721	561	395	278	195	438	5,635
Closings to Plant	-	-	-	-	-	-	(459,811)	(641,535)	(702,510)	(874,995)	(1,031,399)	(1,215,245)	(4,925,495)
CWIP Ending Balance	87,068	89,090	95,064	188,291	198,799	251,971	1,072,891	1,496,916	1,639,189	2,041,656	2,406,599	2,835,571	2,835,571
Mandates													
Electric Distribution Plant													
CWIP Beginning Balance	18,568,030	19,654,334	20,288,807	21,314,946	19,904,351	21,570,600	22,954,726	26,100,388	27,028,975	26,533,987	27,435,291	28,284,304	18,568,030
CWIP Expenditures	1,054,601	2,142,921	2,239,298	1,573,677	3,132,343	3,040,541	3,315,812	3,109,871	2,518,172	2,116,288	1,985,485	(367,480)	25,861,530
AFUDC Debt	25,122	31,516	27,276	27,881	28,832	30,940	39,288	41,166	41,232	41,375	42,908	22,441	399,978
AFUDC Equity	58,660	76,329	65,070	66,513	68,752	73,784	93,693	98,170	98,328	98,668	102,326	53,517	953,811
Closings to Plant	(52,079)	(1,616,294)	(1,305,505)	(3,078,666)	(1,563,678)	(1,761,139)	(303,132)	(2,320,619)	(3,152,720)	(1,355,027)	(1,281,706)	(25,022,431)	(42,812,996)
CWIP Ending Balance	19,654,334	20,288,807	21,314,946	19,904,351	21,570,600	22,954,726	26,100,388	27,028,975	26,533,987	27,435,291	28,284,304	2,970,352	2,970,352
New Business													
Electric Distribution Plant													
CWIP Beginning Balance	2,417,043	2,037,077	1,743,340	1,690,118	1,575,367	2,157,082	2,630,306	6,464,768	9,709,239	9,731,843	8,810,410	8,875,468	2,417,043
CWIP Expenditures	3,306,916	4,839,339	3,660,547	5,363,991	4,670,679	5,365,745	7,393,291	8,796,891	6,318,057	6,334,810	6,013,261	4,289,782	66,353,308
AFUDC Debt	1,748	2,620	1,763	1,825	2,476	2,531	4,977	5,783	5,796	4,421	3,094	2,034	39,069
AFUDC Equity	4,081	6,330	4,207	4,354	5,903	6,036	11,869	13,792	13,822	10,542	7,379	4,852	93,168
Closings to Plant	(3,692,712)	(5,142,026)	(3,719,740)	(5,484,921)	(4,097,342)	(4,901,089)	(3,575,675)	(5,571,995)	(6,315,072)	(7,271,206)	(5,958,676)	(5,659,631)	(61,390,083)
CWIP Ending Balance	2,037,077	1,743,340	1,690,118	1,575,367	2,157,082	2,630,306	6,464,768	9,709,239	9,731,843	8,810,410	8,875,468	7,512,505	7,512,505
Solar													
Electric Distribution Plant													
CWIP Beginning Balance	(13,238,153)	(12,930,038)	(10,397,986)	(10,142,534)	(10,452,068)	(9,886,315)	(260,516)	(176,046)	(109,334)	(71,583)	(49,206)	(35,236)	(13,238,153)
CWIP Expenditures	(529,584)	1,977,303	(2,511,543)	(186,518)	686,709	(375,581)	-	-	-	-	-	-	(939,214)
AFUDC Debt	148	(642)	(148)	(1,241)	9	-	515	358	259	194	149	116	(284)
AFUDC Equity	345	(1,056)	(206)	(2,308)	92	-	1,229	853	618	462	355	276	660
Closings to Plant	837,206	556,448	2,767,349	(119,467)	(121,058)	10,001,381	82,725	65,502	36,875	21,720	13,467	8,799	14,150,947
CWIP Ending Balance	(12,930,038)	(10,397,986)	(10,142,534)	(10,452,068)	(9,886,315)	(260,516)	(176,046)	(109,334)	(71,583)	(49,206)	(35,236)	(26,044)	(26,044)
Electric General Plant													
CWIP Beginning Balance	(746,120)	(746,120)	(622,486)	(539,203)	(741,477)	(741,477)	(741,477)	(593,174)	(474,538)	(379,631)	(303,705)	(242,965)	(746,120)
CWIP Expenditures	(96,548)	123,633	89,795	(202,274)	-	-	-	-	-	-	-	-	(85,394)
AFUDC Debt	-	(71)	(2,064)	0	-	-	4	2	1	1	0	0	(2,128)
AFUDC Equity	-	(130)	(4,447)	1	-	-	10	5	2	1	1	0	(4,557)
Closings to Plant	96,548	201	1	(1)	-	-	148,288	118,629	94,904	75,924	60,740	48,592	643,825
CWIP Ending Balance	(746,120)	(622,486)	(539,203)	(741,477)	(741,477)	(741,477)	(593,174)	(474,538)	(379,631)	(303,705)	(242,965)	(194,372)	(194,372)

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	144,364	10,116	10,116	22,520	44,098	22,540	22,222	15,556	10,889	7,622	5,336	3,735	144,364
CWIP Expenditures	-	-	12,404	21,578	5,030	-	-	-	-	-	-	382,000	421,013
Closings to Plant	(134,249)	-	-	-	(26,589)	(317)	(6,667)	(4,667)	(3,267)	(2,287)	(1,601)	(115,720)	(295,362)
CWIP Ending Balance	10,116	10,116	22,520	44,098	22,540	22,222	15,556	10,889	7,622	5,336	3,735	270,014	270,014
Common Intangible Plant													
CWIP Beginning Balance	1,069,571	1,074,866	1,081,950	-	-	-	-	-	-	-	-	-	1,069,571
CWIP Expenditures	226	304	75	-	-	-	-	-	-	-	-	-	605
AFUDC Debt	1,520	1,982	894	-	-	-	-	-	-	-	-	-	4,396
AFUDC Equity	3,549	4,798	2,134	1	-	-	-	-	-	-	-	-	10,482
Closings to Plant	-	-	(1,085,053)	(1)	-	-	-	-	-	-	-	-	(1,085,054)
CWIP Ending Balance	1,074,866	1,081,950	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant													
CWIP Beginning Balance	743,413	2,357,882	1,511,580	1,536,879	1,468,160	2,110,075	2,544,468	2,263,855	2,272,738	2,332,778	2,390,769	2,437,875	743,413
CWIP Expenditures	1,616,364	(820,344)	62,807	9,933	714,625	513,981	225,000	225,000	225,000	225,000	225,000	225,000	3,447,366
AFUDC Debt	-	-	-	-	-	-	3,191	3,209	3,227	3,245	3,263	3,281	19,416
AFUDC Equity	-	-	-	-	-	-	7,610	7,653	7,695	7,738	7,781	7,824	46,301
Closings to Plant	(1,896)	(25,958)	(37,507)	(78,653)	(72,710)	(79,589)	(516,415)	(226,979)	(175,882)	(177,992)	(188,938)	(198,967)	(1,781,484)
CWIP Ending Balance	2,357,882	1,511,580	1,536,879	1,468,160	2,110,075	2,544,468	2,263,855	2,272,738	2,332,778	2,390,769	2,437,875	2,475,012	2,475,012
Electric General Plant													
CWIP Beginning Balance	1,369,069	1,286,250	1,312,274	1,560,631	1,756,400	1,851,257	2,155,801	2,182,744	2,205,424	1,959,885	1,997,526	1,927,972	1,369,069
CWIP Expenditures	229,148	176,607	422,938	442,876	549,015	369,415	787,262	911,251	793,284	712,481	539,646	1,659,684	7,593,606
AFUDC Debt	1,159	1,182	1,354	1,625	1,878	2,148	2,715	3,032	3,037	2,969	3,019	2,763	26,881
AFUDC Equity	2,707	2,874	3,230	3,875	4,477	5,124	6,473	7,231	7,242	7,079	7,200	6,588	64,102
Closings to Plant	(315,833)	(154,638)	(179,166)	(252,606)	(460,512)	(72,143)	(769,507)	(898,835)	(1,049,103)	(684,888)	(619,419)	(1,146,499)	(6,603,150)
CWIP Ending Balance	1,286,250	1,312,274	1,560,631	1,756,400	1,851,257	2,155,801	2,182,744	2,205,424	1,959,885	1,997,526	1,927,972	2,450,508	2,450,508
Capra													
Coal													
Electric General Plant													
CWIP Beginning Balance	192,497	13,346	13,346	32,443	48,733	71,759	85,401	-	-	-	-	-	192,497
CWIP Expenditures	5,415	-	19,097	16,290	23,026	13,642	68,064	12,000	12,000	12,000	12,000	3,654	197,189
Closings to Plant	(184,567)	-	-	-	-	-	(153,465)	(12,000)	(12,000)	(12,000)	(12,000)	(3,654)	(389,686)
CWIP Ending Balance	13,346	13,346	32,443	48,733	71,759	85,401	-	-	-	-	-	-	-
Electric Steam Production Plant													
CWIP Beginning Balance	9,027,068	10,558,156	11,591,304	12,944,144	13,425,457	11,029,699	12,404,378	12,944,749	15,468,574	6,453,033	5,722,904	4,017,097	9,027,068
CWIP Expenditures	1,592,327	996,187	1,802,341	1,669,958	1,710,691	1,604,242	1,676,582	2,957,173	3,809,954	2,544,821	1,468,803	783,415	22,616,492
AFUDC Debt	13,542	19,304	19,717	20,454	19,762	18,561	20,635	23,177	18,543	10,286	8,152	6,075	198,207
AFUDC Equity	31,619	46,730	47,033	48,785	47,124	44,263	49,209	55,271	44,220	24,529	19,441	14,487	472,711
Closings to Plant	(106,399)	(29,072)	(516,251)	(1,257,884)	(4,173,335)	(292,387)	(1,206,056)	(511,795)	(12,888,257)	(3,309,765)	(3,202,204)	(1,533,669)	(29,027,074)
CWIP Ending Balance	10,558,156	11,591,304	12,944,144	13,425,457	11,029,699	12,404,378	12,944,749	15,468,574	6,453,033	5,722,904	4,017,097	3,287,404	3,287,404
Hydro													
Electric General Plant													
CWIP Expenditures	-	-	-	-	-	-	1,250	1,250	1,250	1,250	1,250	1,250	7,500
Closings to Plant	-	-	-	-	-	-	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(7,500)
Electric Hydro Production Plant													
CWIP Beginning Balance	210,982	213,305	215,187	221,800	223,569	229,782	231,580	239,317	281,980	294,840	301,697	243,070	210,982
CWIP Expenditures	8,199	8,473	4,965	536	4,958	521	6,667	41,667	11,667	6,667	3,667	1,667	99,654
AFUDC Debt	301	394	359	364	371	377	385	426	472	488	446	400	4,782
AFUDC Equity	702	953	855	868	885	900	918	1,017	1,125	1,163	1,065	953	11,403
Closings to Plant	(6,879)	(7,937)	435	-	-	-	(234)	(447)	(404)	(1,461)	(63,805)	(597)	(81,328)
CWIP Ending Balance	213,305	215,187	221,800	223,569	229,782	231,580	239,317	281,980	294,840	301,697	243,070	245,493	245,493
Intermediate													
Electric General Plant													
CWIP Beginning Balance	130,129	130,129	142,190	201,633	201,633	233,835	248,810	30,731	39,898	49,065	5,000	5,000	130,129
CWIP Expenditures	-	36,707	94,913	13,092	39,386	30,132	158,632	31,932	70,632	46,132	33,332	10,967	565,856
Closings to Plant	-	(24,646)	(35,470)	(13,092)	(7,184)	(15,157)	(376,711)	(22,765)	(61,465)	(90,197)	(33,332)	(10,967)	(690,985)
CWIP Ending Balance	130,129	142,190	201,633	201,633	233,835	248,810	30,731	39,898	49,065	5,000	5,000	5,000	5,000
Electric Intangible Plant													
CWIP Beginning Balance	217,101	217,101	228,622	327,932	159,945	170,129	179,130	200,383	237,061	517,722	839,105	1,085,655	217,101
CWIP Expenditures	-	11,521	99,310	17,943	42,272	9,001	21,253	36,678	280,661	321,383	246,550	104,197	1,190,770
Closings to Plant	-	-	-	(185,931)	(32,087)	-	-	-	-	-	-	-	(218,018)
CWIP Ending Balance	217,101	228,622	327,932	159,945	170,129	179,130	200,383	237,061	517,722	839,105	1,085,655	1,189,852	1,189,852
Electric Other Production Plant													
CWIP Beginning Balance	4,794,320	4,967,854	8,769,702	11,614,724	12,911,097	14,026,128	3,315,044	3,795,808	4,597,574	5,413,905	4,099,788	5,158,876	4,794,320
CWIP Expenditures	276,425	4,030,544	2,799,909	2,159,804	1,111,575	6,394,332	1,185,679	2,455,395	1,066,221	1,727,837	2,588,958	4,567,348	30,364,027
AFUDC Debt	5,585	10,293	15,548	19,055	20,859	15,294	5,854	7,006	8,194	8,131	7,712	10,744	134,275
AFUDC Equity	13,040	24,878	37,083	45,456	49,740	36,472	13,961	16,708	19,540	19,390	18,392	25,621	320,281
Closings to Plant	(121,516)	(263,867)	(7,519)	(927,943)	(67,143)	(17,157,181)	(724,731)	(1,677,343)	(277,623)	(3,069,475)	(1,555,975)	(2,719,160)	(28,569,475)
CWIP Ending Balance	4,967,854	8,769,702	11,614,724	12,911,097	14,026,128	3,315,044	3,795,808	4,597,574	5,413,905	4,099,788	5,158,876	7,043,428	7,043,428

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Solar													
Electric Other Production Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	423,193	848,736	1,279,147	1,709,441	2,595,693	-
CWIP Expenditures	-	-	-	-	-	-	422,022	422,022	424,522	422,022	874,336	9,266,547	11,831,471
AFUDC Debt	-	-	-	-	-	-	346	1,040	1,740	2,444	3,520	11,856	20,946
AFUDC Equity	-	-	-	-	-	-	825	2,480	4,150	5,828	8,395	28,272	49,951
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	423,193	848,736	1,279,147	1,709,441	2,595,693	11,902,368	11,902,368
Electric Transmission Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind													
Electric General Plant													
CWIP Beginning Balance	218,380	245,009	279,227	281,599	1,339,193	1,355,188	2,264,320	2,143,240	2,154,700	2,166,223	78,765	78,765	218,380
CWIP Expenditures	26,630	34,218	2,372	1,054,671	10,116	981,728	24,207	98,385	61,574	26,574	25,908	24,741	2,371,124
AFUDC Debt	-	-	-	863	1,737	2,551	3,367	3,386	3,405	1,712	-	-	17,021
AFUDC Equity	-	-	-	2,059	4,142	6,085	8,030	8,074	8,119	4,082	-	-	40,590
Closings to Plant	-	-	-	-	-	(81,232)	(156,684)	(98,385)	(61,574)	(2,119,826)	(25,908)	(24,741)	(2,568,349)
CWIP Ending Balance	245,009	279,227	281,599	1,339,193	1,355,188	2,264,320	2,143,240	2,154,700	2,166,223	78,765	78,765	78,765	78,765
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	69	913	913	4,612	43,157	81,702	120,247	158,792	197,337	-
CWIP Expenditures	-	-	69	843	-	3,699	38,545	38,545	38,545	38,545	38,545	104,545	301,882
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(51,500)	(51,500)
CWIP Ending Balance	-	-	69	913	913	4,612	43,157	81,702	120,247	158,792	197,337	250,382	250,382
Electric Other Production Plant													
CWIP Beginning Balance	752,070,480	443,490,565	479,783,208	473,908,095	485,667,940	227,168,426	289,338,174	348,808,685	375,802,781	443,059,306	452,520,576	499,943,599	752,070,480
CWIP Expenditures	16,771,628	40,898,225	215,757,765	11,280,459	61,188,930	61,408,951	60,479,721	35,142,208	69,800,864	11,412,108	45,957,189	5,498,292	635,596,342
AFUDC Debt	841,919	892,796	779,290	779,083	583,288	422,540	521,231	592,572	669,659	732,454	778,916	499,832	8,093,580
AFUDC Equity	1,965,946	2,165,668	1,859,062	1,858,578	1,390,818	1,007,654	1,243,009	1,413,139	1,596,974	1,746,725	1,857,524	1,191,976	19,297,073
Closings to Plant	(328,159,408)	(7,664,046)	(224,271,231)	(2,158,276)	(321,662,550)	(669,397)	(2,773,449)	(10,153,823)	(4,810,972)	(4,430,017)	(1,170,606)	(397,862,969)	(1,305,786,744)
CWIP Ending Balance	443,490,565	479,783,208	473,908,095	485,667,940	227,168,426	289,338,174	348,808,685	375,802,781	443,059,306	452,520,576	499,943,599	109,270,731	109,270,731
Electric Transmission Plant													
CWIP Beginning Balance	38,316,047	14,550,451	16,767,559	23,002,110	22,567,315	10,876,752	10,680,249	10,023,466	10,102,976	10,159,058	10,215,451	10,272,157	38,316,047
CWIP Expenditures	150,401	2,236,065	16,439,094	(469,972)	1,364,393	(228,083)	1,701,096	90,049	-	-	-	-	21,283,043
AFUDC Debt	6,913	(6,664)	15,021	12,134	12,919	13,762	14,979	16,458	16,569	16,661	16,753	8,423	143,929
AFUDC Equity	16,142	(12,609)	35,811	28,953	30,818	32,819	35,722	39,248	39,513	39,732	39,953	20,087	346,189
Closings to Plant	(23,939,053)	316	(10,255,375)	(5,911)	(13,098,692)	(15,001)	(2,408,580)	(66,245)	-	-	-	(10,300,667)	(60,089,208)
CWIP Ending Balance	14,550,451	16,767,559	23,002,110	22,567,315	10,876,752	10,680,249	10,023,466	10,102,976	10,159,058	10,215,451	10,272,157	-	-
Dispatchable													
Electric General Plant													
CWIP Beginning Balance	31,550	45,485	60,675	13,239	14,260	23,915	18,663	8,665	8,665	8,665	8,665	8,665	31,550
CWIP Expenditures	13,934	15,190	249,227	1,021	9,655	4,718	15,617	8,977	253,977	32,217	8,977	11,250	624,761
Closings to Plant	-	-	(296,663)	-	-	(9,970)	(25,616)	(8,977)	(253,977)	(32,217)	(8,977)	(11,250)	(647,647)
CWIP Ending Balance	45,485	60,675	13,239	14,260	23,915	18,663	8,665	8,665	8,665	8,665	8,665	8,665	8,665
Electric Other Production Plant													
CWIP Beginning Balance	2,751,267	2,861,893	3,441,507	3,551,999	2,893,612	3,501,641	3,749,487	2,599,006	4,019,570	7,335,231	4,987,473	5,276,100	2,751,267
CWIP Expenditures	116,072	566,133	959,575	567,225	561,602	408,006	(951,665)	1,422,938	3,636,607	1,987,879	1,128,694	1,274,595	11,677,661
AFUDC Debt	3,980	5,727	5,887	5,375	5,225	5,921	5,193	5,830	9,708	10,861	8,877	9,764	82,349
AFUDC Equity	9,294	13,842	14,043	12,823	12,458	14,121	12,383	13,903	23,152	25,902	21,170	23,284	196,376
Closings to Plant	(18,721)	(6,089)	(869,012)	(1,243,810)	28,744	(180,201)	(216,393)	(22,107)	(353,807)	(4,372,400)	(870,114)	(463,979)	(8,587,889)
CWIP Ending Balance	2,861,893	3,441,507	3,551,999	2,893,612	3,501,641	3,749,487	2,599,006	4,019,570	7,335,231	4,987,473	5,276,100	6,119,765	6,119,765
Electric Steam Production Plant													
CWIP Beginning Balance	1,370,656	2,477,658	2,555,280	2,846,239	1,314,034	1,579,073	1,862,592	2,628,865	3,133,783	3,189,483	3,662,626	2,635,862	1,370,656
CWIP Expenditures	1,134,644	448,256	1,046,750	1,283,204	409,018	376,640	787,125	564,967	496,258	871,733	834,867	291,600	8,545,062
AFUDC Debt	2,639	4,402	4,461	3,811	2,255	2,701	3,675	4,717	5,233	5,626	5,229	4,367	49,116
AFUDC Equity	6,162	10,619	10,640	9,093	5,377	6,442	8,765	11,248	12,480	13,417	12,469	10,414	117,125
Closings to Plant	(36,444)	(385,654)	(770,891)	(2,828,314)	(151,610)	(102,263)	(33,292)	(76,013)	(458,272)	(417,634)	(1,879,329)	(294,777)	(7,434,493)
CWIP Ending Balance	2,477,658	2,555,280	2,846,239	1,314,034	1,579,073	1,862,592	2,628,865	3,133,783	3,189,483	3,662,626	2,635,862	2,647,466	2,647,466

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Gardner													
Dry Cask Storage													
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	115,000	3,500	500	500	500	120,000
AFUDC Debt	-	-	-	-	-	-	-	47	-	-	-	-	47
AFUDC Equity	-	-	-	-	-	-	-	112	-	-	-	-	112
Closings to Plant	-	-	-	-	-	-	-	(115,160)	(3,500)	(500)	(500)	(500)	(120,160)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	22,080,581	22,482,713	23,206,437	22,712,278	28,513,932	29,399,295	29,867,892	34,642,331	36,828,618	26,033,339	27,707,414	28,454,698	22,080,581
CWIP Expenditures	296,824	580,432	(621,732)	5,659,923	724,993	304,523	4,595,886	1,988,469	1,837,110	1,560,170	639,994	679,810	18,246,402
AFUDC Debt	31,587	41,901	37,682	41,864	47,383	48,465	52,752	58,444	51,872	43,945	45,925	47,212	549,032
AFUDC Equity	73,756	101,392	89,891	99,868	112,987	115,576	125,801	139,375	123,701	104,799	109,521	112,589	1,309,256
Closings to Plant	(35)	-	-	-	-	33	-	-	(12,807,962)	(34,840)	(48,157)	(13,400)	(12,904,361)
CWIP Ending Balance	22,482,713	23,206,437	22,712,278	28,513,932	29,399,295	29,867,892	34,642,331	36,828,618	26,033,339	27,707,414	28,454,698	29,280,909	29,280,909
Facilities & Other													
Electric General Plant													
CWIP Beginning Balance	266,373	123,854	226,013	281,203	354,916	115,420	158,835	114,765	114,765	114,765	114,765	114,765	266,373
CWIP Expenditures	81,950	102,159	55,190	73,713	8,098	43,415	28,751	7,100	5,000	5,000	5,000	5,934	421,310
Closings to Plant	(224,469)	-	-	-	(247,594)	-	(72,821)	(7,100)	(5,000)	(5,000)	(5,000)	(5,934)	(572,918)
CWIP Ending Balance	123,854	226,013	281,203	354,916	115,420	158,835	114,765	114,765	114,765	114,765	114,765	114,765	114,765
Electric Intangible Plant													
CWIP Beginning Balance	2,426,714	2,508,643	2,636,763	2,773,371	2,917,813	3,016,708	-	-	-	-	-	-	2,426,714
CWIP Expenditures	70,406	112,207	121,749	128,864	82,629	52,132	47,900	36,981	27,000	31,132	-	-	711,000
AFUDC Debt	3,455	4,654	4,389	4,601	4,806	2,470	-	-	-	-	-	-	24,375
AFUDC Equity	8,068	11,259	10,470	10,977	11,460	5,891	-	-	-	-	-	-	58,123
Closings to Plant	-	-	-	-	-	(3,077,200)	(47,900)	(36,981)	(27,000)	(31,132)	-	-	(3,220,213)
CWIP Ending Balance	2,508,643	2,636,763	2,773,371	2,917,813	3,016,708	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	174,214	253,338	401,855	741,142	632,406	731,375	740,763	869,721	191,779	247,174	209,740	251,468	174,214
CWIP Expenditures	108,263	147,464	340,436	227,674	90,915	12,604	433,681	297,702	61,429	106,392	117,638	155,001	2,099,199
AFUDC Debt	293	565	917	1,113	1,089	1,177	1,371	954	359	397	377	463	9,076
AFUDC Equity	684	1,361	2,187	2,654	2,598	2,808	3,269	2,275	856	948	899	1,105	21,643
Closings to Plant	(30,115)	(874)	(4,253)	(340,175)	4,366	(7,201)	(309,363)	(978,873)	(7,249)	(145,171)	(77,186)	(93,183)	(1,989,277)
CWIP Ending Balance	253,338	401,855	741,142	632,406	731,375	740,763	869,721	191,779	247,174	209,740	251,468	314,855	314,855
Improvements													
Electric General Plant													
CWIP Beginning Balance	2,170,004	1,231,827	1,705,399	2,237,811	2,902,982	2,176,478	2,623,009	3,265,355	3,913,120	4,378,757	6,673,125	1,925,930	2,170,004
CWIP Expenditures	458,766	490,148	535,005	676,816	348,211	449,122	645,000	647,765	465,637	2,294,368	352,765	1,071,721	8,435,324
Closings to Plant	(1,396,943)	(16,576)	(2,593)	(11,645)	(1,074,715)	(2,592)	(2,654)	-	-	-	(5,099,960)	(2,034,882)	(9,642,558)
CWIP Ending Balance	1,231,827	1,705,399	2,237,811	2,902,982	2,176,478	2,623,009	3,265,355	3,913,120	4,378,757	6,673,125	1,925,930	962,769	962,769
Electric Intangible Plant													
CWIP Beginning Balance	7,705,719	7,868,499	8,308,332	8,911,332	9,607,346	10,454,274	9,720,835	10,924,436	10,279,516	4,796,770	5,262,560	5,637,859	7,705,719
CWIP Expenditures	127,149	389,179	555,171	644,777	791,374	718,929	1,149,434	737,636	658,042	514,744	448,258	1,556,298	8,290,991
AFUDC Debt	11,039	14,814	14,127	15,134	16,414	16,503	16,882	17,351	12,371	8,226	8,914	10,506	162,281
AFUDC Equity	25,777	35,841	33,700	36,103	39,140	39,357	40,260	41,377	29,501	19,617	21,257	25,054	386,982
Closings to Plant	(1,185)	-	-	-	-	(1,508,228)	(2,975)	(1,441,283)	(6,182,660)	(76,796)	(103,130)	(20,100)	(9,336,357)
CWIP Ending Balance	7,868,499	8,308,332	8,911,332	9,607,346	10,454,274	9,720,835	10,924,436	10,279,516	4,796,770	5,262,560	5,637,859	7,209,616	7,209,616
Electric Nuclear Production Plant													
CWIP Beginning Balance	1,269,238	1,333,626	1,390,524	1,458,342	1,557,515	1,604,180	1,913,082	1,998,153	2,579,437	5,201,878	5,091,935	5,735,070	1,269,238
CWIP Expenditures	57,833	40,185	54,006	174,580	37,034	299,426	142,577	611,838	2,602,510	905,631	902,448	667,303	6,495,370
AFUDC Debt	1,759	2,378	2,235	2,363	2,485	2,774	3,108	3,641	6,261	8,542	8,752	9,643	53,940
AFUDC Equity	4,108	5,753	5,331	5,636	5,925	6,615	7,412	8,683	14,930	20,372	20,872	22,995	128,631
Closings to Plant	689	8,582	6,246	(83,406)	1,222	88	(68,025)	(42,878)	(1,260)	(1,044,488)	(288,937)	(262,471)	(1,774,640)
CWIP Ending Balance	1,333,626	1,390,524	1,458,342	1,557,515	1,604,180	1,913,082	1,998,153	2,579,437	5,201,878	5,091,935	5,735,070	6,172,539	6,172,539
Mandated Compliance													
Electric Intangible Plant													
CWIP Beginning Balance	139,941	147,739	235,721	365,486	372,521	380,900	1,569,359	1,701,939	1,942,125	2,576,549	2,751,209	3,611,199	139,941
CWIP Expenditures	7,118	86,813	128,097	4,993	6,292	1,183,062	123,525	230,100	621,917	159,914	842,380	567,470	3,961,682
AFUDC Debt	204	343	493	603	616	1,595	2,675	2,980	3,695	4,357	5,203	6,388	29,150
AFUDC Equity	476	826	1,175	1,439	1,470	3,803	6,379	7,106	8,812	10,390	12,407	15,233	69,517
CWIP Ending Balance	147,739	235,721	365,486	372,521	380,900	1,569,359	1,701,939	1,942,125	2,576,549	2,751,209	3,611,199	4,200,290	4,200,290

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Electric Nuclear Production Plant													
CWIP Beginning Balance	1,120,842	1,131,775	1,134,465	1,139,012	1,143,642	2,537,779	2,550,189	2,567,707	4,093,757	3,166,676	-	-	1,120,842
CWIP Expenditures	35,058	(15,676)	6,516	38,276	1,389,747	8,752	3,630	1,507,612	4,120	50,665	50,460	643,444	3,722,604
AFUDC Debt	266	357	325	332	1,476	2,626	4,185	5,447	5,939	2,617	-	-	23,571
AFUDC Equity	622	863	775	792	3,521	6,262	9,980	12,990	14,164	6,242	-	-	56,210
Closings to Plant	(25,013)	17,146	(3,069)	(34,769)	(607)	(5,229)	(276)	-	(951,303)	(3,226,201)	(50,460)	(643,444)	(4,923,227)
CWIP Ending Balance	1,131,775	1,134,465	1,139,012	1,143,642	2,537,779	2,550,189	2,567,707	4,093,757	3,166,676	-	-	-	-
Nuclear Fuel													
Nuclear Fuel													
CWIP Beginning Balance	135,797,133	136,805,540	138,122,923	138,946,709	140,566,958	142,300,330	149,289,788	154,797,848	156,514,762	86,105,117	86,617,577	87,132,996	135,797,133
CWIP Expenditures	364,011	453,401	73,889,518	877,263	958,427	6,188,195	4,666,401	855,257	1,637,409	548,398	34,509	14,212,964	104,685,752
AFUDC Debt	193,226	252,601	258,955	228,428	231,443	238,437	248,662	254,570	224,100	141,241	142,081	154,553	2,568,296
AFUDC Equity	451,179	611,381	617,712	544,958	551,881	568,613	592,998	607,087	534,424	336,824	338,829	368,571	6,124,456
Closings to Plant	(10)	-	(73,942,400)	(30,400)	(8,377)	(5,787)	-	-	(72,805,578)	(514,003)	-	-	(147,306,554)
CWIP Ending Balance	136,805,540	138,122,923	138,946,709	140,566,958	142,300,330	149,289,788	154,797,848	156,514,762	86,105,117	86,617,577	87,132,996	101,869,084	101,869,084
Reliability													
Electric General Plant													
CWIP Beginning Balance	162,864	221,753	179,657	217,330	305,098	362,590	288,232	151,180	95,262	131,072	254,006	363,801	162,864
CWIP Expenditures	89,611	14,364	57,995	87,768	57,491	10,410	271,537	325,002	250,238	322,684	304,160	332,414	2,123,674
Closings to Plant	(30,723)	(56,459)	(20,322)	-	-	(84,767)	(408,589)	(380,920)	(214,428)	(199,750)	(194,365)	(87,750)	(1,678,073)
CWIP Ending Balance	221,753	179,657	217,330	305,098	362,590	288,232	151,180	95,262	131,072	254,006	363,801	608,465	608,465
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	1,003	2,011	3,025	4,045	4,869	-
CWIP Expenditures	-	-	-	-	-	-	1,000	1,000	1,000	1,000	800	1,643	6,443
AFUDC Debt	-	-	-	-	-	-	1	2	4	6	7	9	30
AFUDC Equity	-	-	-	-	-	-	2	6	10	14	17	22	71
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	1,003	2,011	3,025	4,045	4,869	6,544	6,544
Electric Nuclear Production Plant													
CWIP Beginning Balance	22,405,781	26,772,851	31,725,846	36,192,093	36,318,580	17,655,039	21,561,570	20,647,059	23,193,693	25,692,452	27,809,946	25,499,332	22,405,781
CWIP Expenditures	5,069,408	5,030,850	4,822,012	9,697,506	5,769,265	4,749,047	4,199,306	4,536,837	5,717,505	7,125,886	3,996,309	3,502,160	64,216,092
AFUDC Debt	31,238	48,004	51,257	55,497	43,070	27,249	34,663	36,001	40,362	44,868	44,029	36,854	493,093
AFUDC Equity	72,941	115,921	122,267	132,392	102,698	64,987	82,663	85,853	96,253	106,999	104,999	87,888	1,175,861
Closings to Plant	(806,517)	(241,780)	(529,290)	(9,758,909)	(24,578,575)	(934,752)	(5,231,143)	(2,112,056)	(3,355,360)	(5,160,259)	(6,455,951)	(9,939,716)	(69,104,308)
CWIP Ending Balance	26,772,851	31,725,846	36,192,093	36,318,580	17,655,039	21,561,570	20,647,059	23,193,693	25,692,452	27,809,946	25,499,332	19,186,518	19,186,518
Husen													
Replacements, Additions, & Repairs													
Electric General Plant													
CWIP Beginning Balance	1,616,127	1,876,866	2,861,058	3,711,083	5,240,644	5,804,915	5,125,270	284,278	404,266	523,086	410,656	494,541	1,616,127
CWIP Expenditures	693,930	1,625,679	1,159,985	1,554,596	1,358,935	1,004,119	995,079	1,435,245	2,399,629	2,651,131	1,514,422	3,042,816	19,435,566
Closings to Plant	(433,191)	(641,486)	(309,961)	(25,035)	(794,665)	(1,683,764)	(5,836,071)	(1,315,257)	(2,280,809)	(2,763,561)	(1,430,536)	(2,843,022)	(20,357,357)
CWIP Ending Balance	1,876,866	2,861,058	3,711,083	5,240,644	5,804,915	5,125,270	284,278	404,266	523,086	410,656	494,541	694,336	694,336
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	1,000,062	963,567	898,715	1,430,721	1,531,688	1,620,353	1,583,715	572,959	495,169	557,367	497,756	391,825	1,000,062
CWIP Expenditures	74,991	(61,419)	539,358	102,185	88,781	13,030	79,000	243,000	339,090	190,456	55,051	417,217	2,080,741
Closings to Plant	(111,486)	(3,433)	(7,352)	(1,218)	(117)	(49,667)	(1,089,756)	(320,790)	(276,892)	(250,066)	(160,983)	(211,486)	(2,483,247)
CWIP Ending Balance	963,567	898,715	1,430,721	1,531,688	1,620,353	1,583,715	572,959	495,169	557,367	497,756	391,825	597,556	597,556
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	22,641	23,157	46,390	32,473	22,731	15,912	11,138	-
CWIP Expenditures	361	-	-	-	22,641	517	-	-	-	-	-	-	23,519
Closings to Plant	(361)	-	-	-	-	-	23,232	(13,917)	(9,742)	(6,819)	(4,774)	(3,341)	(15,722)
CWIP Ending Balance	-	-	-	-	22,641	23,157	46,390	32,473	22,731	15,912	11,138	7,797	7,797
PHEV													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	528	528	124,817	-	-	-	-	-	-
CWIP Expenditures	-	-	-	528	-	124,289	29,500	70,000	-	-	-	545,683	770,000
Closings to Plant	-	-	-	-	-	-	(154,317)	(70,000)	-	-	-	(545,683)	(770,000)
CWIP Ending Balance	-	-	-	528	528	124,817	-	-	-	-	-	-	-
Electric General Plant													
CWIP Expenditures	-	-	-	-	-	-	29,500	-	-	-	-	-	29,500
Closings to Plant	-	-	-	-	-	-	(29,500)	-	-	-	-	-	(29,500)

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Fueling Depots													
Common General Plant													
CWIP Expenditures	-	-	-	-	-	-	-	150,000	90,000	210,000	149,789	143,331	743,120
Closings to Plant	-	-	-	-	-	-	-	(150,000)	(90,000)	(210,000)	(149,789)	(143,331)	(743,120)
Moeller													
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	-	-	-	760	1,664	3,680	15,690	187,936	430,005	615,569	791,146	967,697	-
CWIP Expenditures	-	-	758	900	2,004	11,960	171,687	240,362	182,675	171,687	171,687	171,687	1,125,410
AFUDC Debt	-	-	0	1	3	15	165	504	854	1,149	1,437	1,726	5,855
AFUDC Equity	-	-	1	3	8	35	394	1,202	2,036	2,740	3,427	4,117	13,963
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	760	1,664	3,680	15,690	187,936	430,005	615,569	791,146	967,697	1,145,228	1,145,228
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	150,416	452,084	755,426	1,261,007	1,769,395	-
CWIP Expenditures	-	-	-	-	-	-	150,000	300,000	300,000	500,000	500,000	500,000	2,250,000
AFUDC Debt	-	-	-	-	-	-	123	493	987	1,649	2,478	3,312	9,042
AFUDC Equity	-	-	-	-	-	-	293	1,175	2,355	3,932	5,910	7,898	21,563
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	150,416	452,084	755,426	1,261,007	1,769,395	2,280,604	2,280,604
Enterprise Security Capital													
Common General Plant													
CWIP Beginning Balance	230,034	260,610	281,057	288,961	295,344	289,919	74,324	3,250	1,964	1,187	718	435	230,034
CWIP Expenditures	30,470	20,183	7,576	6,017	3,798	3,671	-	-	-	-	-	-	71,716
AFUDC Debt	32	78	97	108	123	120	7	4	3	2	1	1	574
AFUDC Equity	74	186	230	258	295	286	17	10	6	4	2	1	1,369
Closings to Plant	-	-	-	-	(9,641)	(219,672)	(71,097)	(1,301)	(785)	(474)	(286)	(173)	(303,430)
CWIP Ending Balance	260,610	281,057	288,961	295,344	289,919	74,324	3,250	1,964	1,187	718	435	264	264
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	1,698,754	3,406,937	5,124,603	6,851,804	8,588,592	-
CWIP Expenditures	-	-	-	-	-	-	1,694,052	1,694,052	1,694,052	1,694,052	1,694,052	1,694,052	10,164,312
AFUDC Debt	-	-	-	-	-	-	1,389	4,175	6,977	9,793	12,626	15,474	50,435
AFUDC Equity	-	-	-	-	-	-	3,313	9,957	16,637	23,355	30,110	36,903	120,274
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	1,698,754	3,406,937	5,124,603	6,851,804	8,588,592	10,335,021	10,335,021
Electric General Plant													
CWIP Beginning Balance	898,755	879,230	879,735	892,669	910,078	956,809	207,528	208,680	209,839	211,003	212,175	213,353	898,755
CWIP Expenditures	11,977	829	13,173	17,287	46,436	130,978	-	-	-	-	-	-	220,680
AFUDC Debt	-	0	11	36	87	232	340	342	344	346	348	227	2,314
AFUDC Equity	-	1	27	86	208	552	812	816	821	825	830	541	5,519
Closings to Plant	(31,502)	(325)	(278)	-	-	(881,042)	-	-	-	-	-	(150,656)	(1,063,804)
CWIP Ending Balance	879,230	879,735	892,669	910,078	956,809	207,528	208,680	209,839	211,003	212,175	213,353	63,464	63,464
Electric Hydro Production Plant													
CWIP Beginning Balance	8,966	10,323	13,198	19,313	23,926	34,086	44,115	-	-	-	-	-	8,966
CWIP Expenditures	1,311	2,802	6,025	4,493	9,999	9,813	-	-	-	-	-	-	34,444
AFUDC Debt	14	21	27	35	47	64	-	-	-	-	-	-	208
AFUDC Equity	32	51	64	84	113	153	-	-	-	-	-	-	497
Closings to Plant	-	-	-	-	-	-	(44,115)	-	-	-	-	-	(44,115)
CWIP Ending Balance	10,323	13,198	19,313	23,926	34,086	44,115	-	-	-	-	-	-	-
Other													
Common General Plant													
CWIP Beginning Balance	3,327,707	3,410,880	3,531,784	3,732,731	3,771,461	3,797,625	3,821,606	3,154,732	3,168,239	3,181,821	3,396,033	3,611,434	3,327,707
CWIP Expenditures	73,229	107,087	188,158	25,687	12,946	10,645	-	-	-	200,000	200,000	200,000	1,017,753
AFUDC Debt	2,982	4,041	3,777	3,853	3,905	3,940	3,968	3,990	4,013	4,199	4,550	4,903	48,122
AFUDC Equity	6,963	9,776	9,011	9,191	9,312	9,396	9,464	9,516	9,569	10,013	10,851	11,694	114,755
Closings to Plant	-	-	-	-	-	-	(680,306)	-	-	-	-	-	(680,306)
CWIP Ending Balance	3,410,880	3,531,784	3,732,731	3,771,461	3,797,625	3,821,606	3,154,732	3,168,239	3,181,821	3,396,033	3,611,434	3,828,031	3,828,031
Common Intangible Plant													
CWIP Beginning Balance	750,933	2,261,672	1,563,123	274,196	1,659,219	1,970,086	270,806	270,806	270,806	270,806	270,806	270,806	750,933
CWIP Expenditures	1,510,738	(698,549)	(1,288,927)	1,385,023	310,867	(1,699,280)	-	-	-	-	-	-	(480,128)
CWIP Ending Balance	2,261,672	1,563,123	274,196	1,659,219	1,970,086	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
Electric Distribution Plant													
CWIP Beginning Balance	(300,069)	485,349	1,352,643	1,426,466	871,773	428,306	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(300,069)
CWIP Expenditures	785,418	867,294	73,823	(554,693)	(443,468)	(22,324,974)	-	-	-	-	-	-	(21,596,599)
CWIP Ending Balance	485,349	1,352,643	1,426,466	871,773	428,306	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
Electric General Plant													
CWIP Beginning Balance	213,922	213,922	225,443	324,823	157,678	167,863	180,563	180,563	180,563	180,563	180,563	180,563	213,922
CWIP Expenditures	-	11,521	99,380	(167,145)	10,185	12,700	-	-	-	-	-	-	(33,359)
CWIP Ending Balance	213,922	225,443	324,823	157,678	167,863	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Electric Intangible Plant													
CWIP Beginning Balance	(217,101)	(217,101)	(228,622)	(328,002)	(160,857)	(171,042)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(217,101)
CWIP Expenditures	-	(11,521)	(99,380)	167,145	(10,185)	(12,700)	-	-	-	-	-	-	33,359
CWIP Ending Balance	(217,101)	(228,622)	(328,002)	(160,857)	(171,042)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
Electric Other Production Plant													
CWIP Beginning Balance	-	-	-	-	-	-	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	-
CWIP Expenditures	-	-	-	-	-	22,664,537	-	-	-	-	-	-	22,664,537
CWIP Ending Balance	-	-	-	-	-	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
Electric Steam Production Plant													
CWIP Beginning Balance	30,167	30,167	30,167	26,933	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
CWIP Expenditures	-	-	(3,234)	3,234	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	30,167	30,167	26,933	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
Electric Transmission Plant													
CWIP Beginning Balance	604,314	(24,166)	(9,280)	(6,972)	(6,513)	(2,784)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	604,314
CWIP Expenditures	(628,481)	14,886	2,308	459	3,729	115	-	-	-	-	-	-	(606,983)
CWIP Ending Balance	(24,166)	(9,280)	(6,972)	(6,513)	(2,784)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
Property Services Capital													
Common General Plant													
CWIP Beginning Balance	3,362,940	3,305,014	3,791,925	3,417,139	4,189,461	5,656,348	7,833,630	8,237,058	10,019,227	12,669,783	17,966,560	22,962,259	3,362,940
CWIP Expenditures	151,664	485,959	502,404	762,848	1,448,630	2,146,624	1,865,123	1,850,592	2,790,804	5,542,568	6,958,638	14,605,412	39,111,268
AFUDC Debt	4,698	6,392	5,862	6,215	8,054	11,030	13,170	14,939	18,596	25,081	33,748	39,150	186,935
AFUDC Equity	10,970	15,461	13,985	14,826	19,204	26,303	31,406	35,626	44,346	59,811	80,482	93,364	445,786
Closings to Plant	(225,259)	(20,901)	(897,037)	(11,567)	(9,002)	(6,676)	(1,506,271)	(118,987)	(203,191)	(330,683)	(2,077,169)	(14,817,801)	(20,224,543)
CWIP Ending Balance	3,305,014	3,791,925	3,417,139	4,189,461	5,656,348	7,833,630	8,237,058	10,019,227	12,669,783	17,966,560	22,962,259	22,882,385	22,882,385
Electric General Plant													
CWIP Beginning Balance	536,645	566,818	512,729	604,342	659,003	938,515	1,521,710	2,108,074	3,568,407	7,867,028	9,218,800	9,802,315	536,645
CWIP Expenditures	36,956	(49,428)	92,423	52,883	278,304	581,958	866,288	1,458,250	4,286,750	1,334,302	560,793	555,874	10,055,353
AFUDC Debt	371	446	344	349	357	365	2,520	3,836	5,124	6,414	7,465	8,327	35,917
AFUDC Equity	866	1,081	821	832	851	871	6,009	9,148	12,219	15,295	17,802	19,857	85,653
Closings to Plant	(8,021)	(6,188)	(1,975)	597	-	-	(288,451)	(10,902)	(5,472)	(4,239)	(2,545)	(5,007,771)	(5,334,967)
CWIP Ending Balance	566,818	512,729	604,342	659,003	938,515	1,521,710	2,108,074	3,568,407	7,867,028	9,218,800	9,802,315	5,378,603	5,378,603
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	43,584	37,452	37,831	48,113	67,694	99,130	157,089	291,692	474,079	693,035	594,507	679,578	43,584
CWIP Expenditures	867	380	10,282	19,581	31,436	57,958	283,798	429,818	535,063	355,273	351,789	32,849	2,109,094
Closings to Plant	(6,999)	-	-	-	-	-	(149,195)	(247,431)	(316,107)	(453,800)	(266,718)	(179,489)	(1,619,741)
CWIP Ending Balance	37,452	37,831	48,113	67,694	99,130	157,089	291,692	474,079	693,035	594,507	679,578	532,937	532,937
Electric General Plant													
CWIP Beginning Balance	30,093	30,093	30,093	44,349	52,988	55,114	134,633	111,312	72,701	65,661	48,924	37,336	30,093
CWIP Expenditures	-	-	14,256	8,639	2,125	187,526	83,000	7,000	20,000	-	-	14,720	337,267
Closings to Plant	-	-	-	-	-	(108,007)	(106,321)	(45,611)	(27,040)	(16,738)	(11,587)	(11,985)	(327,289)
CWIP Ending Balance	30,093	30,093	44,349	52,988	55,114	134,633	111,312	72,701	65,661	48,924	37,336	40,071	40,071
Remington													
Aging Technology													
Common General Plant													
CWIP Beginning Balance	8,747,967	9,764,191	11,430,436	10,966,484	11,801,730	12,679,325	13,072,940	14,953,960	17,206,572	13,538,585	15,667,301	15,475,294	8,747,967
CWIP Expenditures	1,830,836	1,945,713	1,704,901	1,031,086	1,074,475	1,450,635	3,755,417	3,365,210	5,046,183	2,675,910	2,514,186	2,116,448	28,511,001
Closings to Plant	(814,613)	(279,468)	(2,168,852)	(195,840)	(196,880)	(1,057,020)	(1,874,397)	(1,112,597)	(8,714,171)	(547,195)	(2,706,193)	(12,997,667)	(32,664,893)
CWIP Ending Balance	9,764,191	11,430,436	10,966,484	11,801,730	12,679,325	13,072,940	14,953,960	17,206,572	13,538,585	15,667,301	15,475,294	4,594,075	4,594,075
Common Intangible Plant													
CWIP Beginning Balance	17,307,149	18,592,889	17,724,326	19,086,897	19,937,502	21,240,621	22,376,972	23,099,873	24,804,995	22,000,568	23,971,013	23,251,996	17,307,149
CWIP Expenditures	2,193,893	3,265,585	1,361,601	1,173,373	1,398,099	1,087,784	1,983,439	1,698,802	3,225,251	3,777,671	1,536,050	2,119,523	24,821,072
AFUDC Debt	25,456	34,199	29,946	31,605	33,676	35,612	29,245	30,949	29,327	26,289	25,715	17,212	349,232
AFUDC Equity	59,438	82,738	71,439	75,397	80,302	84,926	69,743	73,806	69,938	62,693	61,324	41,046	832,791
Closings to Plant	(993,046)	(4,251,086)	(100,415)	(429,770)	(208,958)	(71,972)	(1,359,526)	(98,435)	(6,128,943)	(1,896,208)	(2,342,106)	(20,031,943)	(37,912,408)
CWIP Ending Balance	18,592,889	17,724,326	19,086,897	19,937,502	21,240,621	22,376,972	23,099,873	24,804,995	22,000,568	23,971,013	23,251,996	5,397,835	5,397,835
Electric General Plant													
CWIP Beginning Balance	10,573,458	11,119,332	11,630,340	11,364,753	11,513,445	12,078,037	13,330,794	13,964,112	14,825,259	16,217,315	17,600,508	18,196,545	10,573,458
CWIP Expenditures	507,192	457,407	975,172	463,865	514,845	1,534,073	681,271	801,616	1,397,320	1,317,092	527,153	708,857	9,885,863
AFUDC Debt	11,599	15,677	14,643	15,169	15,777	16,328	16,878	17,588	18,563	19,529	20,351	21,203	203,305
AFUDC Equity	27,083	37,924	34,931	36,186	37,620	38,939	40,250	41,943	44,269	46,572	48,533	50,563	484,813
Closings to Plant	-	1	(1,290,333)	(366,529)	(3,648)	(336,584)	(105,082)	-	(68,097)	-	-	(2,846,655)	(5,016,927)
CWIP Ending Balance	11,119,332	11,630,340	11,364,753	11,513,445	12,078,037	13,330,794	13,964,112	14,825,259	16,217,315	17,600,508	18,196,545	16,130,512	16,130,512
Electric Intangible Plant													
CWIP Beginning Balance	7,628,680	7,969,185	8,407,027	9,024,063	7,455,634	7,795,595	8,179,127	5,875,031	5,610,427	6,352,013	7,073,486	7,721,717	7,628,680
CWIP Expenditures	332,152	449,365	586,454	1,588,091	472,843	381,315	419,180	1,780,812	763,180	699,543	612,747	495,589	8,581,272
AFUDC Debt	7,474	13,013	12,854	12,795	12,479	13,060	11,489	8,585	8,167	9,363	10,483	9,373	129,134
AFUDC Equity	17,451	31,375	30,663	30,523	29,755	31,144	27,399	20,474	19,476	22,329	25,000	22,352	307,942
Closings to Plant	(16,572)	(55,910)	(12,936)	(3,199,837)	(175,117)	(41,986)	(2,762,164)	(2,074,475)	(49,237)	(9,762)	-	(2,550,230)	(10,948,227)
CWIP Ending Balance	7,969,185	8,407,027	9,024,063	7,455,634	7,795,595	8,179,127	5,875,031	5,610,427	6,352,013	7,073,486	7,721,717	5,698,801	5,698,801

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
AGIS													
Common General Plant													
CWIP Beginning Balance	1,322,568	1,516,128	1,557,267	1,590,323	1,633,066	1,633,881	886,431	-	-	-	-	-	1,322,568
CWIP Expenditures	190,467	36,457	29,426	38,141	815	-	-	-	-	-	-	-	295,306
AFUDC Debt	927	1,370	1,303	1,359	-	-	-	-	-	-	-	-	4,960
AFUDC Equity	2,165	3,311	3,107	3,243	-	-	-	-	-	-	-	-	11,826
Closings to Plant	-	-	(779)	-	-	(747,450)	(886,431)	-	-	-	-	-	(1,634,660)
CWIP Ending Balance	1,516,128	1,557,267	1,590,323	1,633,066	1,633,881	886,431	-	-	-	-	-	-	-
Electric General Plant													
CWIP Beginning Balance	45,048,854	45,748,887	46,535,084	47,282,325	2,011,657	2,442,367	3,141,270	3,206,190	3,609,818	4,033,645	4,444,396	4,811,584	45,048,854
CWIP Expenditures	498,612	523,988	503,203	470,017	444,592	715,974	433,252	415,426	423,335	397,948	352,232	255,246	5,433,825
AFUDC Debt	61,402	80,672	73,188	58,245	480	1,092	1,751	2,423	3,100	3,782	4,419	4,941	295,495
AFUDC Equity	143,372	195,239	174,592	138,914	1,132	2,604	4,175	5,779	7,393	9,020	10,537	11,784	704,539
Closings to Plant	(3,353)	(13,702)	(3,741)	(45,937,844)	(15,493)	(20,768)	(374,257)	(20,000)	(10,000)	-	-	(10,318)	(46,409,476)
CWIP Ending Balance	45,748,887	46,535,084	47,282,325	2,011,657	2,442,367	3,141,270	3,206,190	3,609,818	4,033,645	4,444,396	4,811,584	5,073,237	5,073,237
Electric Intangible Plant													
CWIP Beginning Balance	3,408,174	3,721,667	4,038,051	4,548,904	4,744,370	5,358,720	5,703,261	5,853,997	6,002,360	6,149,200	6,289,410	6,430,399	3,408,174
CWIP Expenditures	484,880	293,123	493,982	170,060	586,726	314,226	118,783	115,583	113,242	105,818	105,818	105,818	3,008,058
AFUDC Debt	5,054	7,073	7,033	7,584	8,256	9,035	9,440	9,685	9,926	10,161	10,391	10,622	104,261
AFUDC Equity	11,800	17,052	16,777	18,093	19,686	21,547	22,513	23,096	23,672	24,231	24,780	25,331	248,579
Closings to Plant	(188,241)	(865)	(6,939)	(272)	(318)	(266)	-	-	-	-	-	-	(196,901)
CWIP Ending Balance	3,721,667	4,038,051	4,548,904	4,744,370	5,358,720	5,703,261	5,853,997	6,002,360	6,149,200	6,289,410	6,430,399	6,572,170	6,572,170
Cyber Security													
Common General Plant													
CWIP Beginning Balance	234,378	243,849	42,604	63,568	90,070	176,297	75,673	230,061	368,428	333,798	390,797	469,343	234,378
CWIP Expenditures	11,210	25,556	71,920	26,502	86,458	43,854	172,620	138,367	881,009	56,999	78,546	84,807	1,677,847
Closings to Plant	(1,739)	(226,802)	(50,956)	-	(230)	(144,478)	(18,232)	-	(915,639)	-	-	(168,770)	(1,526,845)
CWIP Ending Balance	243,849	42,604	63,568	90,070	176,297	75,673	230,061	368,428	333,798	390,797	469,343	385,380	385,380
Common Intangible Plant													
CWIP Beginning Balance	3,458,310	3,632,858	2,809,886	2,995,058	2,999,872	2,787,672	3,471,442	3,957,158	5,089,486	6,391,260	8,353,384	9,645,492	3,458,310
CWIP Expenditures	196,396	172,516	213,344	192,683	508,904	669,473	955,194	1,110,187	2,156,914	2,531,865	1,268,198	2,326,568	12,302,242
AFUDC Debt	4,202	4,922	3,777	3,884	4,492	4,852	5,329	6,541	7,335	7,676	8,986	6,166	68,162
AFUDC Equity	9,812	11,934	9,010	9,265	10,712	11,571	12,707	15,600	17,493	18,305	21,428	14,704	162,542
Closings to Plant	(35,861)	(1,012,345)	(40,959)	(201,017)	(736,309)	(2,126)	(487,514)	-	(879,968)	(595,722)	(6,503)	(9,543,372)	(13,541,696)
CWIP Ending Balance	3,632,858	2,809,886	2,995,058	2,999,872	2,787,672	3,471,442	3,957,158	5,089,486	6,391,260	8,353,384	9,645,492	2,449,559	2,449,559
Electric General Plant													
CWIP Beginning Balance	-	-	-	18,708	45,680	50,426	75,886	90,012	170,967	242,967	321,090	410,090	-
CWIP Expenditures	91,485	45,512	18,708	26,972	42,681	33,259	19,000	80,955	72,000	78,123	89,000	59,910	657,606
Closings to Plant	(91,485)	(45,512)	-	-	(37,935)	(7,799)	(4,874)	-	-	-	-	-	(187,606)
CWIP Ending Balance	-	-	18,708	45,680	50,426	75,886	90,012	170,967	242,967	321,090	410,090	470,000	470,000
Electric Intangible Plant													
CWIP Beginning Balance	93,784	-	-	-	159	3,091	3,264	3,282	3,300	39,418	426,287	462,807	93,784
CWIP Expenditures	9,700	7,831	2,569	(440)	2,923	155	-	-	36,000	386,550	36,000	36,000	517,288
AFUDC Debt	69	10	0	0	3	5	5	5	35	94	154	107	488
AFUDC Equity	162	28	0	0	6	12	13	13	83	225	367	255	1,164
Closings to Plant	(103,715)	(7,869)	(2,569)	598	-	-	-	-	-	-	-	(499,169)	(612,723)
CWIP Ending Balance	-	-	-	159	3,091	3,264	3,282	3,300	39,418	426,287	462,807	-	-
Emergent Demand													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	(2,494,971)	(4,740,445)	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	(2,772,190)	(2,772,190)	(2,772,190)	(8,316,570)
Closings to Plant	-	-	-	-	-	-	-	-	-	277,219	526,716	751,263	1,555,199
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	(2,494,971)	(4,740,445)	(6,761,371)	(6,761,371)
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	(1,287,450)	(2,188,665)	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	(1,839,214)	(1,839,214)	(1,839,214)	(5,517,642)
Closings to Plant	-	-	-	-	-	-	-	-	-	551,764	937,999	1,208,364	2,698,127
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	(1,287,450)	(2,188,665)	(2,819,515)	(2,819,515)
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	7,799,248	8,022,665	9,165,823	9,194,023	9,498,028	9,756,172	10,241,963	10,807,624	11,249,864	13,520,123	13,726,765	15,993,643	7,799,248
CWIP Expenditures	189,819	1,094,976	70,610	264,739	114,475	436,602	571,392	1,294,723	2,444,678	153,006	2,212,182	691,206	9,538,407
AFUDC Debt	10,075	14,067	13,569	13,774	14,167	14,536	14,907	15,220	15,535	15,846	16,159	16,485	174,341
AFUDC Equity	23,524	34,013	32,369	32,860	33,783	34,665	35,549	36,296	37,047	37,790	38,536	39,312	415,744
Closings to Plant	-	103	(88,348)	(7,368)	95,719	(12)	(56,187)	(904,000)	(227,000)	-	-	(1,341,915)	(2,529,008)
CWIP Ending Balance	8,022,665	9,165,823	9,194,023	9,498,028	9,756,172	10,241,963	10,807,624	11,249,864	13,520,123	13,726,765	15,993,643	15,398,731	15,398,731
Common Intangible Plant													
CWIP Beginning Balance	12,105,045	14,282,935	16,263,397	15,827,175	17,670,609	19,087,613	20,329,363	18,771,916	20,248,709	21,918,854	22,808,731	22,157,983	12,105,045
CWIP Expenditures	2,244,341	2,541,020	1,218,418	1,798,079	1,406,619	1,232,526	3,162,088	1,958,357	1,656,096	2,608,924	1,860,903	1,781,123	23,468,492
AFUDC Debt	18,633	27,576	26,297	27,357	30,056	32,223	31,186	30,382	32,787	34,765	34,976	18,697	344,936
AFUDC Equity	43,509	66,625	62,730	65,262	71,671	76,844	74,371	72,454	78,188	82,907	83,410	44,587	822,558
Closings to Plant	(128,593)	(654,759)	(1,743,666)	(47,263)	(91,343)	(99,843)	(4,825,092)	(584,402)	(96,926)	(1,836,719)	(2,630,037)	(22,765,475)	(35,504,117)
CWIP Ending Balance	14,282,935	16,263,397	15,827,175	17,670,609	19,087,613	20,329,363	18,771,916	20,248,709	21,918,854	22,808,731	22,157,983	1,236,914	1,236,914

Northern States Power Company
CWIP by Witness, Functional Class, and Category

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 16 of 49

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 Year-to-date
Electric General Plant													
CWIP Beginning Balance	2,210,349	2,095,555	2,146,502	2,204,283	2,254,513	1,627,260	1,656,631	1,683,419	1,715,096	1,726,827	1,763,320	1,796,114	2,210,349
CWIP Expenditures	91,875	88,476	271,124	80,852	20,232	23,682	26,787	31,678	33,594	36,493	32,794	29,547	767,134
Closings to Plant	(206,669)	(37,528)	(213,343)	(30,622)	(647,485)	5,689	-	-	(21,863)	-	-	(1,825,661)	(2,977,483)
CWIP Ending Balance	2,095,555	2,146,502	2,204,283	2,254,513	1,627,260	1,656,631	1,683,419	1,715,096	1,726,827	1,763,320	1,796,114	-	-
Electric Intangible Plant													
CWIP Beginning Balance	1,691,691	2,386,488	3,876,207	5,949,817	6,581,694	7,955,862	9,900,848	11,496,101	13,539,310	14,744,373	15,692,675	16,351,504	1,691,691
CWIP Expenditures	685,167	1,470,885	2,046,369	597,218	1,333,923	1,895,574	1,802,024	1,974,423	1,912,780	867,204	571,199	6,371,176	21,527,943
AFUDC Debt	2,888	5,525	8,047	10,238	11,891	14,598	17,427	20,322	22,958	24,640	25,890	18,645	183,069
AFUDC Equity	6,743	13,309	19,193	24,422	28,354	34,814	41,559	48,464	54,749	58,760	61,741	44,465	436,571
Closings to Plant	-	-	-	-	-	-	(265,757)	-	(785,425)	(2,302)	-	(19,155,747)	(20,209,231)
CWIP Ending Balance	2,386,488	3,876,207	5,949,817	6,581,694	7,955,862	9,900,848	11,496,101	13,539,310	14,744,373	15,692,675	16,351,504	3,630,043	3,630,043
Customer													
Common General Plant													
CWIP Beginning Balance	-	16,217	96,416	1,371,109	1,338,825	2,985,412	3,041,089	3,041,089	3,041,089	3,041,089	3,690,933	2,019,906	-
CWIP Expenditures	16,217	80,199	1,274,693	(32,284)	1,646,587	55,677	-	-	-	649,844	423,600	15,000	4,129,533
Closings to Plant	-	-	-	-	-	-	-	-	-	-	(2,094,627)	(2,034,906)	(4,129,533)
CWIP Ending Balance	16,217	96,416	1,371,109	1,338,825	2,985,412	3,041,089	3,041,089	3,041,089	3,041,089	3,690,933	2,019,906	-	-
Common Intangible Plant													
CWIP Beginning Balance	14,115,906	16,822,049	17,377,485	19,157,430	20,926,444	22,536,494	23,943,361	26,493,805	28,449,615	30,884,087	33,062,059	30,608,587	14,115,906
CWIP Expenditures	3,368,466	1,259,734	588,456	1,664,812	2,103,211	1,371,865	2,410,843	1,803,736	2,270,247	2,000,981	1,656,017	1,832,202	22,330,571
AFUDC Debt	21,929	31,113	29,973	32,758	35,561	38,008	41,244	44,929	48,519	52,291	52,247	26,794	455,365
AFUDC Equity	51,205	75,215	71,499	78,145	84,796	90,640	98,357	107,144	115,706	124,701	124,595	63,897	1,085,900
Closings to Plant	(735,456)	(810,627)	1,090,017	(6,701)	(613,519)	(93,645)	-	-	-	-	(4,286,330)	(31,155,111)	(36,611,373)
CWIP Ending Balance	16,822,049	17,377,485	19,157,430	20,926,444	22,536,494	23,943,361	26,493,805	28,449,615	30,884,087	33,062,059	30,608,587	1,376,369	1,376,369

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

Northern States Power Company
CWIP by Witness, Functional Class, and Category

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 17 of 49

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Benson													
Asset Renewal													
Electric General Plant													
CWIP Beginning Balance	1,188,205	1,315,645	1,481,919	2,610,191	2,330,284	1,771,136	2,853,454	2,979,905	3,295,969	5,376,399	6,173,337	5,564,908	1,188,205
CWIP Expenditures	120,899	159,000	1,627,410	121,300	116,400	1,591,610	124,300	313,300	2,635,610	792,300	98,100	2,522,510	10,222,739
AFUDC Debt	1,912	2,127	2,208	1,868	1,218	701	629	808	934	1,356	1,301	705	15,766
AFUDC Equity	4,629	5,147	5,344	4,522	2,947	1,697	1,522	1,955	2,261	3,282	3,148	1,706	38,161
Closings to Plant	-	-	(506,691)	(407,596)	(679,712)	(511,691)	-	-	(558,375)	-	(710,978)	(3,731,399)	(7,106,441)
CWIP Ending Balance	1,315,645	1,481,919	2,610,191	2,330,284	1,771,136	2,853,454	2,979,905	3,295,969	5,376,399	6,173,337	5,564,908	4,358,430	4,358,430
Electric Transmission Plant													
CWIP Beginning Balance	20,441,113	30,864,154	34,827,484	37,572,471	48,700,590	45,495,956	42,243,375	54,012,924	62,811,326	68,977,223	79,014,478	92,349,973	20,441,113
CWIP Expenditures	11,498,653	11,730,627	15,679,050	12,346,081	12,558,724	14,750,593	13,260,476	14,153,185	19,701,145	14,648,058	15,811,392	19,393,659	175,531,643
AFUDC Debt	39,839	51,042	57,401	66,669	73,337	69,283	74,519	91,063	103,346	114,284	132,131	117,291	990,205
AFUDC Equity	96,427	123,543	138,935	161,365	177,505	167,692	180,367	220,408	250,140	276,614	319,810	283,891	2,396,696
Closings to Plant	(1,211,878)	(7,941,881)	(13,130,399)	(1,445,997)	(16,014,199)	(18,240,148)	(1,745,813)	(5,666,253)	(13,888,734)	(5,001,701)	(2,927,838)	(57,995,274)	(145,210,117)
CWIP Ending Balance	30,864,154	34,827,484	37,572,471	48,700,590	45,495,956	42,243,375	54,012,924	62,811,326	68,977,223	79,014,478	92,349,973	54,149,539	54,149,539
Comm Infrastructure													
Electric General Plant													
CWIP Beginning Balance	1,357,006	1,634,258	1,512,064	1,432,551	1,589,354	1,965,185	1,934,434	2,251,923	2,556,646	2,850,340	6,714,185	7,148,576	1,357,006
CWIP Expenditures	314,400	357,104	330,392	356,772	416,500	387,602	309,000	292,100	364,500	4,141,072	398,000	2,062,904	9,730,346
AFUDC Debt	2,296	2,416	2,268	2,358	2,728	3,032	3,213	3,691	4,179	7,342	10,639	6,337	50,499
AFUDC Equity	5,557	5,847	5,490	5,707	6,603	7,340	7,777	8,932	10,114	17,771	25,752	15,339	122,229
Closings to Plant	(45,000)	(487,561)	(417,664)	(208,033)	(50,000)	(428,726)	(2,500)	-	(85,099)	(302,341)	-	(9,177,034)	(11,203,958)
CWIP Ending Balance	1,634,258	1,512,064	1,432,551	1,589,354	1,965,185	1,934,434	2,251,923	2,556,646	2,850,340	6,714,185	7,148,576	56,122	56,122
Electric Transmission Plant													
CWIP Beginning Balance	505,513	2,039,610	3,581,783	5,132,074	6,690,525	8,257,180	9,832,082	11,415,274	13,006,801	14,606,705	16,313,288	17,920,772	505,513
CWIP Expenditures	1,899,424	1,527,808	1,527,416	1,527,416	1,527,416	1,527,416	1,527,416	1,527,416	1,527,416	1,625,416	1,517,616	1,527,416	18,789,592
AFUDC Debt	1,953	4,314	6,688	9,074	11,472	13,883	16,307	18,743	21,193	23,730	26,274	14,378	168,010
AFUDC Equity	4,728	10,442	16,187	21,962	27,767	33,603	39,469	45,367	51,295	57,437	63,594	34,800	406,651
Closings to Plant	(372,008)	(392)	-	-	-	-	-	-	-	-	-	(19,497,365)	(19,869,765)
CWIP Ending Balance	2,039,610	3,581,783	5,132,074	6,690,525	8,257,180	9,832,082	11,415,274	13,006,801	14,606,705	16,313,288	17,920,772	-	-
Interconnection													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	(25,439)	25,890	150,049	(66,063)	96,880	(186,550)	159,117	412,553	611,319	705,926	709,945	753,730	(25,439)
CWIP Expenditures	47,343	119,943	1,467,943	160,043	(286,557)	1,689,943	249,843	194,943	1,439,943	83,943	39,943	1,500,845	6,708,118
AFUDC Debt	1,165	1,233	1,532	848	914	1,473	1,051	1,118	1,676	1,155	1,123	1,756	15,044
AFUDC Equity	2,820	2,984	3,709	2,053	2,213	3,565	2,543	2,705	4,057	2,795	2,719	4,249	36,412
Closings to Plant	-	-	(1,689,297)	-	-	(1,349,315)	-	-	(1,351,069)	(83,874)	-	(1,380,194)	(5,853,749)
CWIP Ending Balance	25,890	150,049	(66,063)	96,880	(186,550)	159,117	412,553	611,319	705,926	709,945	753,730	880,387	880,387
Regional Expansion													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	381,700	580,225	779,796	1,766,580	1,972,395	2,110,513	992,189	1,598,991	3,111,356	4,621,757	5,648,717	7,082,137	381,700
CWIP Expenditures	1,268,666	1,268,666	2,052,766	196,000	127,400	529,300	619,600	1,500,000	1,490,100	1,000,000	1,400,000	1,890,100	13,342,598
AFUDC Debt	738	1,044	1,954	2,870	3,134	2,400	1,989	3,615	5,935	7,882	9,771	12,354	53,685
AFUDC Equity	1,787	2,526	4,730	6,946	7,584	5,808	4,813	8,750	14,365	19,079	23,649	29,901	129,939
Closings to Plant	(1,072,666)	(1,072,666)	(1,072,666)	-	-	(1,655,831)	(19,600)	-	-	-	-	-	(4,893,429)
CWIP Ending Balance	580,225	779,796	1,766,580	1,972,395	2,110,513	992,189	1,598,991	3,111,356	4,621,757	5,648,717	7,082,137	9,014,492	9,014,492

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Reliability Requirement													
Electric General Plant													
CWIP Beginning Balance	20,590	20,699	119,066	119,693	169,452	364,108	366,025	367,962	369,899	371,836	373,783	375,751	20,590
CWIP Expenditures	1	98,000	-	49,000	196,000	-	10	-	(10)	(10)	-	10	343,001
AFUDC Debt	32	107	183	222	410	560	563	566	569	572	575	289	4,649
AFUDC Equity	77	260	444	537	991	1,356	1,363	1,371	1,378	1,385	1,392	700	11,254
Closings to Plant	-	-	-	-	(2,744)	-	-	-	-	-	-	(376,750)	(379,494)
CWIP Ending Balance	20,699	119,066	119,693	169,452	364,108	366,025	367,962	369,899	371,836	373,783	375,751	-	-
Electric Transmission Plant													
CWIP Beginning Balance	8,655,520	11,353,815	12,735,800	14,249,948	15,043,973	15,881,855	11,900,678	14,071,100	11,984,159	13,922,415	16,200,301	20,105,115	8,655,520
CWIP Expenditures	2,663,590	1,336,570	1,712,129	1,465,002	774,520	1,126,061	2,118,200	(2,147,360)	2,121,248	2,198,811	3,809,509	3,801,691	20,979,971
AFUDC Debt	10,146	13,278	15,597	17,283	18,525	16,506	15,268	17,664	19,979	23,119	27,864	29,533	224,762
AFUDC Equity	24,558	32,138	37,752	41,832	44,837	39,952	36,954	42,755	48,358	55,957	67,442	71,481	544,016
Closings to Plant	-	-	(251,330)	(730,092)	-	(5,163,696)	-	-	(251,330)	-	-	(6,008,730)	(12,405,179)
CWIP Ending Balance	11,353,815	12,735,800	14,249,948	15,043,973	15,881,855	11,900,678	14,071,100	11,984,159	13,922,415	16,200,301	20,105,115	17,999,090	17,999,090
Security\Resiliency													
Electric General Plant													
CWIP Beginning Balance	476,979	1,536,205	2,137,790	2,123,249	3,291,404	4,002,492	4,647,891	6,681,572	8,793,536	8,944,563	10,228,234	10,955,182	476,979
CWIP Expenditures	1,053,941	591,941	591,941	1,153,941	691,941	1,391,940	2,003,941	2,071,340	571,342	1,233,340	671,340	571,341	12,598,289
AFUDC Debt	1,545	2,820	3,291	4,156	5,598	6,641	8,695	11,877	13,615	14,715	16,258	8,850	98,058
AFUDC Equity	3,740	6,825	7,965	10,058	13,549	16,073	21,046	28,747	32,953	35,616	39,351	21,420	237,341
Closings to Plant	-	-	(617,737)	-	-	(769,255)	-	-	(466,882)	-	-	(11,280,847)	(13,134,721)
CWIP Ending Balance	1,536,205	2,137,790	2,123,249	3,291,404	4,002,492	4,647,891	6,681,572	8,793,536	8,944,563	10,228,234	10,955,182	275,946	275,946
Electric Intangible Plant													
CWIP Beginning Balance	-	62,163	124,654	-	62,163	124,654	-	62,163	124,654	-	62,163	124,654	-
CWIP Expenditures	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	62,000	744,000
AFUDC Debt	48	143	120	48	143	120	48	143	120	48	143	120	1,243
AFUDC Equity	115	347	290	115	347	290	115	347	290	115	347	290	3,010
Closings to Plant	-	-	(187,063)	-	-	(187,063)	-	-	(187,063)	-	-	(187,063)	(748,253)
CWIP Ending Balance	62,163	124,654	-	62,163	124,654	-	62,163	124,654	-	62,163	124,654	-	-
Electric Transmission Plant													
CWIP Beginning Balance	943,626	3,059,436	5,988,489	7,374,503	10,376,402	12,892,786	13,756,264	16,360,625	18,536,935	20,504,534	24,111,356	26,333,480	943,626
CWIP Expenditures	2,105,301	2,905,300	2,356,728	2,955,300	2,455,300	2,306,708	2,525,300	2,084,700	2,441,128	3,489,700	2,089,700	3,656,711	31,371,876
AFUDC Debt	3,073	6,944	10,258	13,624	17,859	20,456	23,114	26,784	29,965	34,242	38,716	24,279	249,314
AFUDC Equity	7,437	16,808	24,829	32,975	43,226	49,512	55,946	64,827	72,528	82,880	93,708	58,764	603,440
Closings to Plant	-	-	(1,005,802)	-	-	(1,513,198)	-	-	(576,022)	-	-	(26,448,598)	(29,543,620)
CWIP Ending Balance	3,059,436	5,988,489	7,374,503	10,376,402	12,892,786	13,756,264	16,360,625	18,536,935	20,504,534	24,111,356	26,333,480	3,624,635	3,624,635
Bloch													
AGIS													
Electric Distribution Plant													
CWIP Beginning Balance	7,751,605	41,012	82,239	123,684	165,346	207,229	249,331	291,655	334,202	376,973	419,969	463,191	7,751,605
CWIP Expenditures	5,859,634	6,058,094	6,458,564	6,727,909	6,458,564	6,458,564	6,727,909	6,458,564	6,458,564	6,727,909	7,437,603	7,437,603	79,269,483
AFUDC Debt	31	95	158	222	286	350	415	480	546	612	678	744	4,617
AFUDC Equity	76	229	383	537	692	848	1,005	1,163	1,321	1,480	1,641	1,802	11,176
Closings to Plant	(13,570,335)	(6,017,190)	(6,417,660)	(6,687,005)	(6,417,660)	(6,417,660)	(6,687,005)	(6,417,660)	(6,417,660)	(6,687,005)	(7,396,699)	(7,396,699)	(86,530,240)
CWIP Ending Balance	41,012	82,239	123,684	165,346	207,229	249,331	291,655	334,202	376,973	419,969	463,191	506,641	506,641
Electric General Plant													
CWIP Beginning Balance	387,174	918,528	1,325,245	1,732,208	2,091,131	2,919,186	3,425,714	3,794,848	4,442,518	5,310,739	6,202,307	7,312,603	387,174
CWIP Expenditures	629,294	533,108	551,846	515,828	992,773	701,649	528,180	783,268	995,499	1,013,439	1,225,190	726,822	9,196,896
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(97,939)	(126,391)	(144,884)	(156,904)	(164,718)	(195,121)	(159,046)	(135,598)	(127,278)	(121,871)	(114,895)	(99,978)	(1,644,623)
CWIP Ending Balance	918,528	1,325,245	1,732,208	2,091,131	2,919,186	3,425,714	3,794,848	4,442,518	5,310,739	6,202,307	7,312,603	7,939,447	7,939,447
Electric Intangible Plant													
CWIP Beginning Balance	1,969,723	2,136,320	2,303,795	2,472,151	2,691,525	2,912,054	3,133,744	3,356,601	3,530,499	3,705,313	3,933,183	4,152,227	1,969,723
CWIP Expenditures	155,819	155,819	155,819	205,819	205,819	205,819	205,819	155,819	155,819	207,819	197,819	197,819	2,205,828
AFUDC Debt	3,151	3,408	3,665	3,963	4,301	4,640	4,981	5,286	5,553	5,862	6,205	5,989	57,005
AFUDC Equity	7,627	8,248	8,872	9,592	10,409	11,231	12,057	12,794	13,441	14,189	15,020	14,496	137,976
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(751,418)	(751,418)
CWIP Ending Balance	2,136,320	2,303,795	2,472,151	2,691,525	2,912,054	3,133,744	3,356,601	3,530,499	3,705,313	3,933,183	4,152,227	3,619,114	3,619,114
Asset Health & Reliability													
Electric Distribution Plant													
CWIP Beginning Balance	33,061,543	36,004,992	38,144,314	40,429,806	42,858,008	46,065,913	49,919,699	54,030,522	57,795,458	60,336,934	58,992,268	59,443,541	33,061,543
CWIP Expenditures	14,333,362	14,333,362	14,146,639	14,398,104	15,239,964	15,916,443	16,750,462	16,750,462	15,737,897	13,639,584	12,970,120	14,523,233	178,739,632
AFUDC Debt	23,375	27,043	30,115	33,579	37,803	43,143	48,631	53,638	57,795	59,006	59,061	48,310	521,499
AFUDC Equity	56,577	65,455	72,890	81,274	91,498	104,425	117,706	129,825	139,888	142,819	142,951	116,930	1,262,237
Closings to Plant	(11,469,865)	(12,286,537)	(11,964,151)	(12,084,754)	(12,161,360)	(12,210,226)	(12,805,975)	(13,168,989)	(13,394,103)	(15,186,076)	(12,720,859)	(29,303,791)	(168,756,686)
CWIP Ending Balance	36,004,992	38,144,314	40,429,806	42,858,008	46,065,913	49,919,699	54,030,522	57,795,458	60,336,934	58,992,268	59,443,541	44,828,224	44,828,224

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Electric General Plant													
CWIP Beginning Balance	21,745	24,476	26,396	27,746	28,696	29,363	29,832	31,311	32,350	33,081	32,447	32,001	21,745
CWIP Expenditures	13,094	13,094	13,094	13,094	13,094	13,094	14,731	14,731	14,731	13,094	13,094	14,731	163,676
AFUDC Debt	37	41	43	45	46	47	49	51	52	52	51	52	564
AFUDC Equity	90	98	104	109	112	114	118	122	126	125	123	125	1,365
Closings to Plant	(10,490)	(11,313)	(11,891)	(12,298)	(12,584)	(12,785)	(13,419)	(13,864)	(14,178)	(13,906)	(13,715)	(14,072)	(154,515)
CWIP Ending Balance	24,476	26,396	27,746	28,696	29,363	29,832	31,311	32,350	33,081	32,447	32,001	32,836	32,836
Capacity													
Electric Distribution Plant													
CWIP Beginning Balance	3,802,742	7,158,394	10,358,416	13,530,767	17,173,855	19,319,350	15,593,982	17,550,848	19,456,829	21,106,778	10,771,851	10,897,982	3,802,742
CWIP Expenditures	4,009,078	4,012,462	4,094,185	4,638,065	3,338,795	3,783,871	3,145,396	3,145,396	2,924,086	2,068,359	1,422,447	1,595,854	38,177,994
AFUDC Debt	7,710	12,182	16,636	21,526	25,713	24,759	22,721	25,470	28,032	21,531	13,420	12,519	232,220
AFUDC Equity	18,662	29,485	40,266	52,102	62,237	59,927	54,993	61,649	67,849	52,113	32,482	30,301	562,067
Closings to Plant	(679,799)	(854,106)	(978,737)	(1,068,605)	(1,281,250)	(7,593,926)	(1,266,244)	(1,326,534)	(1,370,018)	(12,476,930)	(1,342,218)	(2,927,557)	(33,165,924)
CWIP Ending Balance	7,158,394	10,358,416	13,530,767	17,173,855	19,319,350	15,593,982	17,550,848	19,456,829	21,106,778	10,771,851	10,897,982	9,609,099	9,609,099
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicles													
Electric Distribution Plant													
CWIP Beginning Balance	2,835,571	7,266,699	10,383,205	12,575,105	14,116,711	15,200,950	15,963,514	17,160,002	18,001,180	18,592,561	18,348,161	18,176,487	2,835,571
CWIP Expenditures	7,529,600	7,529,600	7,529,600	7,529,600	7,529,600	7,529,600	8,470,800	8,470,800	8,470,800	7,529,600	7,529,600	8,470,800	94,120,000
AFUDC Debt	4,628	10,774	15,095	18,134	20,270	21,772	23,382	24,900	25,968	26,166	25,918	26,296	243,303
AFUDC Equity	11,201	26,076	36,536	43,891	49,062	52,698	56,593	60,269	62,853	63,332	62,732	63,648	588,890
Closings to Plant	(3,114,300)	(4,449,945)	(5,389,331)	(6,050,019)	(6,514,693)	(6,841,506)	(7,354,287)	(7,714,791)	(7,968,240)	(7,863,497)	(7,789,923)	(8,021,169)	(79,071,702)
CWIP Ending Balance	7,266,699	10,383,205	12,575,105	14,116,711	15,200,950	15,963,514	17,160,002	18,001,180	18,592,561	18,348,161	18,176,487	18,716,062	18,716,062
Mandates													
Electric Distribution Plant													
CWIP Beginning Balance	2,970,352	3,934,785	4,750,404	5,443,565	6,036,994	6,716,011	7,497,213	8,408,721	9,224,848	9,807,515	9,993,871	10,198,237	2,970,352
CWIP Expenditures	2,324,499	2,324,499	2,324,499	2,324,499	2,490,324	2,656,149	2,925,984	2,925,984	2,760,159	2,324,499	2,324,499	2,594,334	30,299,928
AFUDC Debt	2,869	3,813	4,625	5,332	6,083	7,022	8,089	9,148	10,032	10,569	10,915	7,521	86,017
AFUDC Equity	6,944	9,228	11,194	12,906	14,723	16,996	19,580	22,143	24,281	25,580	26,418	18,204	208,195
Closings to Plant	(1,369,879)	(1,521,921)	(1,647,156)	(1,749,308)	(1,832,112)	(1,898,964)	(2,042,145)	(2,141,148)	(2,211,805)	(2,174,292)	(2,157,465)	(7,252,940)	(27,999,135)
CWIP Ending Balance	3,934,785	4,750,404	5,443,565	6,036,994	6,716,011	7,497,213	8,408,721	9,224,848	9,807,515	9,993,871	10,198,237	5,565,356	5,565,356
New Business													
Electric Distribution Plant													
CWIP Beginning Balance	7,512,505	7,282,641	7,212,111	7,224,254	7,271,820	7,332,461	7,403,521	7,804,337	8,054,703	8,217,636	7,072,082	6,941,797	7,512,505
CWIP Expenditures	4,813,794	4,813,794	4,818,044	4,818,044	4,818,044	4,826,544	5,419,237	5,419,237	5,419,237	4,818,044	4,809,504	5,410,737	60,204,260
AFUDC Debt	1,412	1,366	1,340	1,331	1,330	1,342	1,358	1,371	1,386	706	6	4	12,950
AFUDC Equity	3,417	3,305	3,244	3,221	3,218	3,247	3,287	3,318	3,355	1,708	14	10	31,344
Closings to Plant	(5,048,487)	(4,888,994)	(4,810,486)	(4,775,028)	(4,761,952)	(4,760,073)	(5,023,066)	(5,173,560)	(5,261,044)	(5,966,011)	(4,939,810)	(5,137,728)	(60,546,240)
CWIP Ending Balance	7,282,641	7,212,111	7,224,254	7,271,820	7,332,461	7,403,521	7,804,337	8,054,703	8,217,636	7,072,082	6,941,797	7,214,820	7,214,820
Solar													
Electric Distribution Plant													
CWIP Beginning Balance	(26,044)	(19,712)	(15,161)	(11,790)	(9,235)	(7,269)	(5,742)	(4,546)	(3,606)	(2,864)	(2,278)	(1,815)	(26,044)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	86	68	54	43	35	28	22	18	14	12	9	8	398
AFUDC Equity	208	165	131	105	84	68	54	44	35	28	23	18	962
Closings to Plant	6,039	4,317	3,186	2,406	1,846	1,432	1,119	879	692	546	432	342	23,237
CWIP Ending Balance	(19,712)	(15,161)	(11,790)	(9,235)	(7,269)	(5,742)	(4,546)	(3,606)	(2,864)	(2,278)	(1,815)	(1,447)	(1,447)
Electric General Plant													
CWIP Beginning Balance	(194,372)	(155,498)	(124,399)	(99,519)	(79,615)	(63,692)	(50,954)	(40,763)	(32,611)	(26,088)	(20,871)	(16,697)	(194,372)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	0	0	0	0	-	-	-	-	-	-	-	-	0
AFUDC Equity	0	0	0	0	0	-	-	-	-	-	-	-	0
Closings to Plant	38,874	31,099	24,880	19,904	15,923	12,738	10,191	8,153	6,522	5,218	4,174	3,339	181,015
CWIP Ending Balance	(155,498)	(124,399)	(99,519)	(79,615)	(63,692)	(50,954)	(40,763)	(32,611)	(26,088)	(20,871)	(16,697)	(13,357)	(13,357)

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	270,014	208,245	165,007	134,740	113,553	98,723	88,341	83,479	80,075	77,692	73,620	70,769	270,014
CWIP Expenditures	27,479	27,479	27,479	27,479	27,479	27,479	30,914	30,914	30,914	27,479	27,479	30,914	343,488
Closings to Plant	(89,248)	(70,717)	(57,746)	(48,666)	(42,310)	(37,861)	(35,777)	(34,318)	(33,297)	(31,551)	(30,330)	(30,505)	(542,324)
CWIP Ending Balance	208,245	165,007	134,740	113,553	98,723	88,341	83,479	80,075	77,692	73,620	70,769	71,178	71,178
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant													
CWIP Beginning Balance	2,475,012	2,368,921	2,297,940	2,251,515	2,222,287	2,205,112	2,196,390	2,196,404	2,199,750	2,205,445	2,210,003	2,216,583	2,475,012
CWIP Expenditures	32,000	32,000	32,000	32,000	32,000	32,000	36,000	36,000	36,000	32,000	32,000	36,000	400,000
AFUDC Debt	3,096	3,112	3,129	3,145	3,162	3,178	3,195	3,212	3,229	3,246	3,263	3,280	38,246
AFUDC Equity	7,493	7,533	7,572	7,612	7,652	7,693	7,733	7,774	7,815	7,856	7,897	7,939	92,570
Closings to Plant	(148,680)	(113,627)	(89,126)	(71,985)	(59,989)	(51,592)	(46,914)	(43,640)	(41,348)	(38,544)	(36,581)	(36,406)	(778,432)
CWIP Ending Balance	2,368,921	2,297,940	2,251,515	2,222,287	2,205,112	2,196,390	2,196,404	2,199,750	2,205,445	2,210,003	2,216,583	2,227,395	2,227,395
Electric General Plant													
CWIP Beginning Balance	2,450,508	2,648,753	2,822,875	2,979,398	3,210,601	3,444,305	3,744,190	4,121,137	4,461,031	4,700,441	4,872,105	5,013,535	2,450,508
CWIP Expenditures	1,139,802	1,139,802	1,139,802	1,236,489	1,261,830	1,350,485	1,479,101	1,479,101	1,402,677	1,318,738	1,276,518	1,699,813	15,924,158
AFUDC Debt	2,673	3,131	3,502	3,881	4,293	4,738	5,277	5,817	6,252	6,563	6,821	7,327	60,276
AFUDC Equity	6,469	7,579	8,476	9,395	10,390	11,469	12,772	14,080	15,132	15,886	16,509	17,735	145,893
Closings to Plant	(950,698)	(976,391)	(995,257)	(1,018,561)	(1,042,809)	(1,066,807)	(1,120,204)	(1,159,104)	(1,184,651)	(1,169,523)	(1,158,417)	(1,249,514)	(13,091,938)
CWIP Ending Balance	2,648,753	2,822,875	2,979,398	3,210,601	3,444,305	3,744,190	4,121,137	4,461,031	4,700,441	4,872,105	5,013,535	5,488,896	5,488,896
Capra													
Coal													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	10,333	14,667	20,000	26,000	181,333	36,667	40,000	34,667	29,333	23,333	21,667	8,000	446,000
Closings to Plant	(10,333)	(14,667)	(20,000)	(26,000)	(181,333)	(36,667)	(40,000)	(34,667)	(29,333)	(23,333)	(21,667)	(8,000)	(446,000)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant													
CWIP Beginning Balance	3,287,404	3,470,047	3,939,492	4,961,605	4,916,688	5,121,449	5,850,435	7,301,157	7,758,105	8,608,965	5,662,357	3,740,674	3,287,404
CWIP Expenditures	447,668	511,228	1,042,417	1,770,656	875,754	1,288,771	1,634,911	942,270	1,200,079	773,278	743,507	597,958	11,828,498
AFUDC Debt	5,191	5,690	6,835	7,703	7,781	8,459	10,101	11,572	12,570	11,043	7,225	5,311	99,481
AFUDC Equity	12,564	13,772	16,544	18,645	18,833	20,474	24,448	28,008	30,425	26,727	17,488	12,855	240,784
Closings to Plant	(282,780)	(61,245)	(43,683)	(1,841,922)	(697,607)	(588,717)	(218,739)	(524,903)	(392,214)	(3,757,657)	(2,689,902)	(1,244,360)	(12,343,730)
CWIP Ending Balance	3,470,047	3,939,492	4,961,605	4,916,688	5,121,449	5,850,435	7,301,157	7,758,105	8,608,965	5,662,357	3,740,674	3,112,437	3,112,437
Hydro													
Electric General Plant													
CWIP Expenditures	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
Closings to Plant	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(15,000)
Electric Hydro Production Plant													
CWIP Beginning Balance	245,493	248,441	251,406	254,379	257,354	260,247	267,439	274,670	281,916	272,362	275,307	278,332	245,493
CWIP Expenditures	1,667	1,667	1,667	1,667	1,667	5,833	5,833	5,833	5,833	5,833	5,833	1,667	45,000
AFUDC Debt	379	384	388	393	397	405	416	427	427	420	425	430	4,891
AFUDC Equity	918	929	940	951	962	980	1,007	1,034	1,034	1,017	1,028	1,040	11,838
Closings to Plant	(15)	(14)	(21)	(35)	(132)	(27)	(25)	(49)	(16,848)	(4,325)	(4,262)	(65)	(25,819)
CWIP Ending Balance	248,441	251,406	254,379	257,354	260,247	267,439	274,670	281,916	272,362	275,307	278,332	281,403	281,403
Intermediate													
Electric General Plant													
CWIP Beginning Balance	5,000	5,058	5,183	5,375	5,642	5,975	6,375	6,850	7,433	8,200	8,967	9,600	5,000
CWIP Expenditures	73,058	52,725	68,107	332,434	192,433	38,828	189,075	54,011	107,867	168,094	66,203	6,785	1,349,620
Closings to Plant	(73,000)	(52,600)	(67,915)	(332,168)	(192,100)	(38,428)	(188,600)	(53,428)	(107,100)	(167,328)	(65,570)	(6,385)	(1,344,620)
CWIP Ending Balance	5,058	5,183	5,375	5,642	5,975	6,375	6,850	7,433	8,200	8,967	9,600	10,000	10,000
Electric Intangible Plant													
CWIP Beginning Balance	1,189,852	1,202,322	1,214,792	1,227,262	1,239,732	1,252,202	1,264,672	1,277,142	1,289,612	1,302,082	1,314,552	1,327,022	1,189,852
CWIP Expenditures	12,470	12,470	12,470	12,470	12,470	12,470	12,470	12,470	12,470	12,470	12,470	12,470	149,640
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(1,339,492)	(1,339,492)
CWIP Ending Balance	1,202,322	1,214,792	1,227,262	1,239,732	1,252,202	1,264,672	1,277,142	1,289,612	1,302,082	1,314,552	1,327,022	-	-
Electric Other Production Plant													
CWIP Beginning Balance	7,043,428	7,921,279	8,771,271	9,675,316	13,634,186	13,722,788	14,855,643	16,526,660	22,799,320	25,502,465	12,668,154	7,245,799	7,043,428
CWIP Expenditures	902,596	869,952	1,325,780	4,603,949	1,202,873	1,268,486	2,295,197	7,173,057	3,616,553	6,772,951	3,180,725	1,200,942	34,413,061
AFUDC Debt	11,485	12,811	14,220	17,985	21,052	21,939	24,095	30,227	37,172	30,438	15,682	11,015	248,124
AFUDC Equity	27,799	31,009	34,418	43,531	50,955	53,102	58,320	73,162	89,972	73,672	37,957	26,661	600,559
Closings to Plant	(64,029)	(63,780)	(470,373)	(706,595)	(1,186,279)	(210,673)	(706,596)	(1,003,786)	(1,040,553)	(19,711,372)	(8,656,720)	(1,546,972)	(35,367,727)
CWIP Ending Balance	7,921,279	8,771,271	9,675,316	13,634,186	13,722,788	14,855,643	16,526,660	22,799,320	25,502,465	12,668,154	7,245,799	6,937,446	6,937,446

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Solar													
Electric Other Production Plant													
CWIP Beginning Balance	11,902,368	12,446,250	12,992,995	13,546,127	33,126,671	46,809,878	70,728,311	93,612,133	116,616,416	139,741,794	163,308,931	181,733,511	11,902,368
CWIP Expenditures	479,965	479,965	483,465	19,458,024	13,473,367	23,609,884	22,452,414	22,452,414	22,452,414	22,771,602	17,518,812	6,624,127	172,256,451
AFUDC Debt	18,687	19,524	20,368	35,820	61,350	90,208	126,128	161,346	196,750	232,585	264,813	284,785	1,512,365
AFUDC Equity	45,230	47,256	49,299	86,700	148,491	218,340	305,281	390,523	476,214	562,950	640,955	689,295	3,660,534
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	12,446,250	12,992,995	13,546,127	33,126,671	46,809,878	70,728,311	93,612,133	116,616,416	139,741,794	163,308,931	181,733,511	189,331,718	189,331,718
Electric Transmission Plant													
CWIP Beginning Balance	-	10,026	20,105	30,238	40,423	50,662	60,955	71,302	81,704	92,160	102,672	113,239	-
CWIP Expenditures	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	120,000
AFUDC Debt	8	23	39	54	70	86	102	117	133	150	166	182	1,129
AFUDC Equity	19	56	94	131	169	207	246	284	323	362	401	440	2,732
CWIP Ending Balance	10,026	20,105	30,238	40,423	50,662	60,955	71,302	81,704	92,160	102,672	113,239	123,861	123,861
Wind													
Electric General Plant													
CWIP Beginning Balance	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765
CWIP Expenditures	43,109	55,264	61,592	62,053	61,015	60,357	59,953	59,596	59,250	58,880	56,546	38,892	676,506
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(43,109)	(55,264)	(61,592)	(62,053)	(61,015)	(60,357)	(59,953)	(59,596)	(59,250)	(58,880)	(56,546)	(38,892)	(676,506)
CWIP Ending Balance	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765
Electric Intangible Plant													
CWIP Beginning Balance	250,382	170,881	207,881	244,880	281,879	318,879	355,878	392,877	429,877	467,876	507,542	551,208	250,382
CWIP Expenditures	57,624	57,624	55,124	40,124	40,124	40,128	40,124	40,124	41,124	42,791	46,791	52,291	553,992
Closings to Plant	(137,125)	(20,625)	(18,125)	(3,125)	(3,125)	(3,129)	(3,125)	(3,125)	(3,125)	(3,125)	(3,125)	(395,125)	(596,000)
CWIP Ending Balance	170,881	207,881	244,880	281,879	318,879	355,878	392,877	429,877	467,876	507,542	551,208	208,374	208,374
Electric Other Production Plant													
CWIP Beginning Balance	109,270,731	177,062,330	179,162,482	186,987,910	215,705,070	260,020,750	296,189,436	355,890,237	386,767,682	419,603,806	432,080,586	458,102,570	109,270,731
CWIP Expenditures	69,818,290	1,337,927	(176,915)	27,738,492	43,379,453	34,774,704	58,829,269	29,138,064	30,880,200	11,642,031	24,046,881	52,599,622	384,008,017
AFUDC Debt	219,783	273,396	281,014	309,060	365,116	426,882	500,506	569,978	618,877	653,711	683,206	414,775	5,316,303
AFUDC Equity	531,962	661,728	680,167	748,051	883,728	1,033,226	1,211,425	1,379,577	1,497,932	1,582,245	1,653,634	1,003,922	12,867,596
Closings to Plant	(2,778,436)	(172,899)	7,041,162	(78,443)	(312,617)	(66,125)	(840,398)	(210,174)	(160,885)	(1,401,206)	(361,738)	(455,464,875)	(454,806,634)
CWIP Ending Balance	177,062,330	179,162,482	186,987,910	215,705,070	260,020,750	296,189,436	355,890,237	386,767,682	419,603,806	432,080,586	458,102,570	56,656,013	56,656,013
Electric Transmission Plant													
CWIP Beginning Balance	-	100,263	201,054	302,376	504,494	807,939	1,112,982	1,519,893	1,928,947	2,340,154	2,753,525	3,169,072	-
CWIP Expenditures	100,000	100,000	100,000	200,000	300,000	300,000	400,000	400,000	400,000	400,000	400,000	400,000	3,500,000
AFUDC Debt	77	231	386	619	1,007	1,474	2,021	2,647	3,276	3,909	4,545	5,185	25,379
AFUDC Equity	186	560	935	1,499	2,438	3,568	4,891	6,407	7,930	9,462	11,002	12,550	61,428
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	100,263	201,054	302,376	504,494	807,939	1,112,982	1,519,893	1,928,947	2,340,154	2,753,525	3,169,072	3,586,807	3,586,807
Dispatchable													
Electric General Plant													
CWIP Beginning Balance	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665
CWIP Expenditures	1,733	2,200	21,667	7,567	7,933	8,100	8,500	3,933	4,667	4,567	2,533	1,600	75,000
Closings to Plant	(1,733)	(2,200)	(21,667)	(7,567)	(7,933)	(8,100)	(8,500)	(3,933)	(4,667)	(4,567)	(2,533)	(1,600)	(75,000)
CWIP Ending Balance	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665
Electric Other Production Plant													
CWIP Beginning Balance	6,119,765	7,345,963	9,461,179	7,743,169	7,862,263	8,412,576	8,606,577	10,133,071	11,144,745	7,794,460	8,752,000	8,785,037	6,119,765
CWIP Expenditures	1,214,954	2,075,270	3,404,450	1,847,111	1,087,821	3,185,929	1,599,983	988,387	1,458,052	2,893,574	804,054	993,876	21,553,460
AFUDC Debt	10,720	13,285	14,149	12,388	12,879	13,483	14,768	16,717	15,134	13,180	13,879	14,513	165,095
AFUDC Equity	25,947	32,154	34,246	29,984	31,173	32,634	35,745	40,462	36,631	31,901	33,592	35,127	399,598
Closings to Plant	(25,423)	(5,493)	(5,170,856)	(1,770,390)	(581,560)	(3,038,045)	(124,002)	(33,891)	(4,860,103)	(1,981,115)	(818,488)	(241,414)	(18,650,780)
CWIP Ending Balance	7,345,963	9,461,179	7,743,169	7,862,263	8,412,576	8,606,577	10,133,071	11,144,745	7,794,460	8,752,000	8,785,037	9,587,138	9,587,138
Electric Steam Production Plant													
CWIP Beginning Balance	2,647,466	4,668,971	5,531,611	3,059,447	2,344,458	1,540,819	2,375,152	3,340,522	5,010,783	4,682,422	2,804,282	2,763,692	2,647,466
CWIP Expenditures	2,025,408	1,466,090	1,370,643	557,132	569,824	844,400	971,600	1,695,667	1,462,933	382,593	599,967	601,900	12,548,157
AFUDC Debt	5,621	7,831	6,964	4,181	2,991	3,006	4,388	6,412	7,713	5,788	4,288	4,602	63,784
AFUDC Equity	13,605	18,954	16,855	10,119	7,240	7,276	10,620	15,520	18,669	14,008	10,378	11,139	154,383
Closings to Plant	(23,128)	(630,235)	(3,866,626)	(1,286,421)	(1,383,693)	(20,349)	(21,238)	(47,338)	(1,817,676)	(2,280,530)	(655,223)	(161,871)	(12,194,329)
CWIP Ending Balance	4,668,971	5,531,611	3,059,447	2,344,458	1,540,819	2,375,152	3,340,522	5,010,783	4,682,422	2,804,282	2,763,692	3,219,462	3,219,462

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Gardner													
Dry Cask Storage													
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	29,280,909	30,891,616	33,303,964	35,441,810	36,069,548	37,309,419	40,718,713	18,827,773	19,080,198	18,580,326	19,948,187	20,498,149	29,280,909
CWIP Expenditures	1,452,749	2,243,828	1,957,382	440,015	1,047,244	3,204,463	1,670,260	152,914	469,260	1,267,720	444,787	1,900,499	16,251,121
AFUDC Debt	46,181	49,269	52,761	54,884	56,317	59,885	45,913	29,094	28,906	29,570	31,042	33,008	516,829
AFUDC Equity	111,777	119,250	127,703	132,840	136,310	144,946	111,128	70,418	69,965	71,571	75,134	79,894	1,250,935
Closings to Plant	-	-	-	-	-	-	(23,718,241)	-	(1,068,004)	(1,000)	(1,000)	(936)	(24,789,181)
CWIP Ending Balance	30,891,616	33,303,964	35,441,810	36,069,548	37,309,419	40,718,713	18,827,773	19,080,198	18,580,326	19,948,187	20,498,149	22,510,614	22,510,614
Facilities & Other													
Electric General Plant													
CWIP Beginning Balance	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765
CWIP Expenditures	500	500	500	500	10,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	100,000
Closings to Plant	(500)	(500)	(500)	(500)	(10,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(100,000)
CWIP Ending Balance	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	314,855	433,230	436,073	467,645	541,756	609,165	692,365	644,967	708,303	800,766	909,234	769,917	314,855
CWIP Expenditures	116,411	561	29,200	71,461	64,388	79,783	176,050	60,283	89,106	103,979	82,321	59,783	933,328
AFUDC Debt	574	667	694	775	883	999	1,027	1,039	1,158	1,312	1,298	1,083	11,508
AFUDC Equity	1,390	1,615	1,679	1,875	2,138	2,418	2,486	2,514	2,803	3,177	3,141	2,620	27,855
Closings to Plant	-	-	-	-	-	-	(226,961)	(500)	(604)	-	(226,077)	(204,354)	(658,497)
CWIP Ending Balance	433,230	436,073	467,645	541,756	609,165	692,365	644,967	708,303	800,766	909,234	769,917	629,049	629,049
Improvements													
Electric General Plant													
CWIP Beginning Balance	962,769	1,076,769	1,232,769	1,379,269	1,525,880	1,672,991	1,824,102	1,978,714	2,169,325	2,377,936	4,466,547	4,556,658	962,769
CWIP Expenditures	120,180	161,150	150,620	789,857	147,677	151,611	155,111	191,111	208,611	2,088,611	90,111	398,828	4,653,479
Closings to Plant	(6,180)	(5,150)	(4,120)	(643,246)	(566)	(500)	(500)	(500)	-	-	-	(4,605,486)	(5,266,248)
CWIP Ending Balance	1,076,769	1,232,769	1,379,269	1,525,880	1,672,991	1,824,102	1,978,714	2,169,325	2,377,936	4,466,547	4,556,658	350,000	350,000
Electric Intangible Plant													
CWIP Beginning Balance	7,209,616	7,472,486	7,742,234	7,873,426	7,998,475	7,514,045	7,626,234	7,364,893	7,569,655	7,740,257	7,824,015	7,920,089	7,209,616
CWIP Expenditures	224,328	229,808	90,200	83,384	97,881	72,544	92,821	170,337	132,802	44,095	55,940	15,400	1,309,538
AFUDC Debt	11,268	11,677	11,985	12,181	11,907	11,620	11,507	11,462	11,750	11,945	12,083	12,201	141,586
AFUDC Equity	27,274	28,263	29,008	29,484	28,820	28,125	27,851	27,743	28,440	28,912	29,246	29,531	342,696
Closings to Plant	-	-	-	-	(623,038)	(100)	(393,519)	(4,779)	(2,390)	(1,195)	(1,195)	-	(1,026,216)
CWIP Ending Balance	7,472,486	7,742,234	7,873,426	7,998,475	7,514,045	7,626,234	7,364,893	7,569,655	7,740,257	7,824,015	7,920,089	7,977,221	7,977,221
Electric Nuclear Production Plant													
CWIP Beginning Balance	6,172,539	7,290,724	6,917,820	7,558,110	8,201,770	8,862,855	9,567,526	10,361,050	11,369,384	12,383,025	13,402,002	14,426,344	6,172,539
CWIP Expenditures	1,083,151	1,102,597	752,597	752,597	766,597	706,597	919,597	956,597	956,597	952,597	952,597	785,368	10,687,491
AFUDC Debt	10,243	11,009	11,020	12,005	13,007	14,055	15,269	16,588	18,139	19,699	21,268	22,348	184,651
AFUDC Equity	24,792	26,647	26,673	29,058	31,481	34,019	36,958	40,149	43,905	47,681	51,476	54,092	446,929
Closings to Plant	-	(1,513,157)	(150,000)	(150,000)	(150,000)	(50,000)	(178,300)	(5,000)	(5,000)	(1,000)	(1,000)	(490,130)	(2,693,587)
CWIP Ending Balance	7,290,724	6,917,820	7,558,110	8,201,770	8,862,855	9,567,526	10,361,050	11,369,384	12,383,025	13,402,002	14,426,344	14,798,022	14,798,022
Mandated Compliance													
Electric Intangible Plant													
CWIP Beginning Balance	4,200,290	4,481,480	4,663,888	5,250,280	5,436,734	6,027,195	6,217,739	6,723,564	6,917,774	7,113,006	8,094,964	9,003,520	4,200,290
CWIP Expenditures	258,400	158,400	560,367	158,400	560,367	158,400	471,853	158,400	158,400	942,035	863,671	791,509	5,240,202
AFUDC Debt	6,663	7,019	7,609	8,202	8,798	9,398	9,932	10,469	10,768	11,672	13,123	14,465	118,119
AFUDC Equity	16,127	16,989	18,417	19,852	21,296	22,746	24,040	25,340	26,064	28,250	31,762	35,012	285,896
CWIP Ending Balance	4,481,480	4,663,888	5,250,280	5,436,734	6,027,195	6,217,739	6,723,564	6,917,774	7,113,006	8,094,964	9,003,520	9,844,506	9,844,506

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Electric Nuclear Production Plant													
CWIP Beginning Balance	-	-	-	-	111,404	348,723	587,291	827,115	1,068,201	1,310,557	1,554,188	1,799,102	-
CWIP Expenditures	10,000	5,000	-	111,111	236,111	236,111	236,111	236,111	236,111	236,111	236,111	236,111	2,015,000
AFUDC Debt	-	-	-	86	353	718	1,086	1,455	1,826	2,199	2,574	2,209	12,504
AFUDC Equity	-	-	-	207	855	1,739	2,627	3,521	4,419	5,322	6,229	5,347	30,265
Closings to Plant	(10,000)	(5,000)	-	-	-	-	-	-	-	-	-	(1,021,469)	(1,036,469)
CWIP Ending Balance	-	-	-	111,404	348,723	587,291	827,115	1,068,201	1,310,557	1,554,188	1,799,102	1,021,300	1,021,300
Nuclear Fuel													
Nuclear Fuel													
CWIP Beginning Balance	101,869,084	103,576,768	105,897,606	106,524,892	107,292,615	115,252,995	119,592,854	120,456,347	127,041,490	50,524,760	50,912,091	52,210,123	101,869,084
CWIP Expenditures	1,168,370	1,770,949	69,658	206,432	7,376,178	3,723,367	233,342	5,935,439	61,127	122,428	1,560,121	64,594,805	86,822,216
AFUDC Debt	157,676	160,767	163,030	164,101	170,799	180,240	184,233	189,950	136,449	77,851	79,144	130,057	1,794,296
AFUDC Equity	381,638	389,122	394,598	397,190	413,403	436,252	445,918	459,755	330,261	188,430	191,561	314,791	4,342,919
Closings to Plant	-	-	-	-	-	-	-	-	(77,044,566)	(1,378)	(532,795)	-	(77,578,739)
CWIP Ending Balance	103,576,768	105,897,606	106,524,892	107,292,615	115,252,995	119,592,854	120,456,347	127,041,490	50,524,760	50,912,091	52,210,123	117,249,775	117,249,775
Reliability													
Electric General Plant													
CWIP Beginning Balance	608,465	667,790	1,087,796	417,355	462,402	508,609	1,565,304	1,837,690	65,556	66,667	77,778	88,889	608,465
CWIP Expenditures	70,325	431,006	244,370	147,876	186,587	1,195,556	459,192	239,460	347,311	559,112	207,449	158,339	4,246,580
Closings to Plant	(11,000)	(11,000)	(914,811)	(102,829)	(140,380)	(138,861)	(186,806)	(2,011,595)	(346,200)	(548,001)	(196,338)	(147,228)	(4,755,045)
CWIP Ending Balance	667,790	1,087,796	417,355	462,402	508,609	1,565,304	1,837,690	65,556	66,667	77,778	88,889	100,000	100,000
Electric Intangible Plant													
CWIP Beginning Balance	6,544	165,751	170,585	246,440	515,831	533,929	551,434	569,031	650,570	746,445	813,628	822,710	6,544
CWIP Expenditures	158,755	3,951	74,760	267,390	15,342	14,656	14,656	78,337	92,208	63,088	4,786	2,393	790,322
AFUDC Debt	132	258	320	585	806	833	860	936	1,072	1,197	1,256	1,268	9,523
AFUDC Equity	320	625	775	1,416	1,950	2,016	2,081	2,266	2,595	2,898	3,040	3,069	23,051
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	165,751	170,585	246,440	515,831	533,929	551,434	569,031	650,570	746,445	813,628	822,710	829,440	829,440
Electric Nuclear Production Plant													
CWIP Beginning Balance	19,186,518	29,837,327	32,097,992	34,371,724	37,437,711	31,848,072	36,550,910	44,151,318	48,340,379	54,239,071	62,404,271	63,334,122	19,186,518
CWIP Expenditures	10,570,928	2,468,410	2,418,854	3,090,513	4,473,356	5,489,566	8,522,236	7,469,072	8,529,800	15,914,319	10,728,815	7,219,447	86,895,315
AFUDC Debt	37,615	47,527	51,072	55,103	53,471	52,486	61,928	71,347	78,850	91,087	96,952	89,426	786,863
AFUDC Equity	91,045	115,035	123,616	133,371	129,421	127,036	149,891	172,689	190,849	220,467	234,662	216,446	1,904,526
Closings to Plant	(48,779)	(370,307)	(319,810)	(213,000)	(10,245,886)	(966,250)	(1,133,646)	(3,524,047)	(2,900,807)	(8,060,672)	(10,130,578)	(18,519,381)	(56,433,162)
CWIP Ending Balance	29,837,327	32,097,992	34,371,724	37,437,711	31,848,072	36,550,910	44,151,318	48,340,379	54,239,071	62,404,271	63,334,122	52,340,060	52,340,060
Husen													
Replacements, Additions, & Repairs													
Electric General Plant													
CWIP Beginning Balance	694,336	500,522	407,095	486,198	501,486	491,040	518,728	450,610	542,927	451,265	403,385	363,701	694,336
CWIP Expenditures	517,644	852,707	3,775,693	4,088,539	4,008,329	3,750,429	2,676,663	3,526,663	1,655,640	1,721,091	1,432,297	406,487	28,412,182
Closings to Plant	(711,458)	(946,134)	(3,696,590)	(4,073,251)	(4,018,775)	(3,722,741)	(2,744,781)	(3,434,346)	(1,747,302)	(1,768,970)	(1,471,981)	(473,244)	(28,809,574)
CWIP Ending Balance	500,522	407,095	486,198	501,486	491,040	518,728	450,610	542,927	451,265	403,385	363,701	296,944	296,944
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	597,556	441,709	326,762	241,907	179,215	197,071	146,583	110,482	103,194	75,877	55,846	41,141	597,556
CWIP Expenditures	-	-	54,667	125,000	135,872	25,000	27,000	55,000	100,000	100,000	-	-	622,539
Closings to Plant	(155,847)	(114,948)	(139,521)	(187,692)	(118,016)	(75,489)	(63,100)	(62,289)	(127,316)	(120,032)	(14,705)	(10,806)	(1,189,760)
CWIP Ending Balance	441,709	326,762	241,907	179,215	197,071	146,583	110,482	103,194	75,877	55,846	41,141	30,335	30,335
Electric General Plant													
CWIP Beginning Balance	7,797	5,458	3,820	55,174	91,122	133,785	268,650	328,055	474,638	472,247	365,573	290,901	7,797
CWIP Expenditures	-	-	75,000	75,000	100,000	250,000	200,000	350,000	200,000	50,000	50,000	16,000	1,366,000
Closings to Plant	(2,339)	(1,637)	(23,646)	(39,052)	(57,337)	(115,136)	(140,595)	(203,416)	(202,392)	(156,674)	(124,672)	(92,070)	(1,158,966)
CWIP Ending Balance	5,458	3,820	55,174	91,122	133,785	268,650	328,055	474,638	472,247	365,573	290,901	214,831	214,831
PHEV													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	10,000	14,000	46,000	70,000	70,000	70,000	50,000	205,800	95,000	25,000	25,000	12,400	693,200
Closings to Plant	(10,000)	(14,000)	(46,000)	(70,000)	(70,000)	(70,000)	(50,000)	(205,800)	(95,000)	(25,000)	(25,000)	(12,400)	(693,200)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Expenditures	-	-	-	-	-	38,950	-	-	-	116,850	116,850	-	272,650
Closings to Plant	-	-	-	-	-	(38,950)	-	-	-	(116,850)	(116,850)	-	(272,650)

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Fueling Depots													
Common General Plant													
CWIP Expenditures	-	-	-	-	100,000	-	100,000	-	20,000	-	-	-	220,000
Closings to Plant	-	-	-	-	(100,000)	-	(100,000)	-	(20,000)	-	-	-	(220,000)
Moeller													
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	1,145,228	1,294,702	1,444,963	1,595,202	1,747,049	1,899,695	2,053,145	2,207,402	2,362,471	2,518,357	2,675,063	2,832,594	1,145,228
CWIP Expenditures	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	1,716,876
AFUDC Debt	1,871	2,101	2,333	2,565	2,799	3,034	3,270	3,507	3,746	3,986	4,227	4,469	37,908
AFUDC Equity	4,529	5,086	5,646	6,209	6,774	7,343	7,914	8,489	9,067	9,647	10,231	10,818	91,754
Closings to Plant	-	-	(812)	-	-	-	-	-	-	-	-	-	(812)
CWIP Ending Balance	1,294,702	1,444,963	1,595,202	1,747,049	1,899,695	2,053,145	2,207,402	2,362,471	2,518,357	2,675,063	2,832,594	2,990,954	2,990,954
Common Intangible Plant													
CWIP Beginning Balance	2,280,604	3,591,185	4,908,665	6,233,079	7,564,466	8,902,861	10,248,301	11,600,824	12,960,466	14,327,265	15,701,260	17,082,487	2,280,604
CWIP Expenditures	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	1,295,167	15,542,000
AFUDC Debt	4,506	6,523	8,551	10,589	12,638	14,698	16,769	18,850	20,943	23,046	25,161	13,643	175,919
AFUDC Equity	10,908	15,789	20,697	25,630	30,590	35,575	40,587	45,625	50,690	55,781	60,899	33,022	425,795
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(18,424,319)	(18,424,319)
CWIP Ending Balance	3,591,185	4,908,665	6,233,079	7,564,466	8,902,861	10,248,301	11,600,824	12,960,466	14,327,265	15,701,260	17,082,487	-	-
Enterprise Security Capital													
Common General Plant													
CWIP Beginning Balance	264	160	98	60	37	23	14	9	5	3	2	1	264
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	0	0	0	0	0	0	0	0	0	-	-	-	1
AFUDC Equity	1	0	0	0	0	0	0	0	0	0	-	-	2
Closings to Plant	(105)	(63)	(38)	(23)	(14)	(9)	(5)	(3)	(2)	(1)	(1)	(1)	(266)
CWIP Ending Balance	160	98	60	37	23	14	9	5	3	2	1	1	1
Common Intangible Plant													
CWIP Beginning Balance	10,335,021	10,956,476	11,581,203	12,209,218	12,840,538	13,475,183	14,113,168	14,754,511	15,399,230	16,047,343	16,698,868	17,353,822	10,335,021
CWIP Expenditures	565,563	565,563	565,563	565,563	565,563	565,563	565,563	565,563	565,563	565,563	565,563	565,563	6,786,756
AFUDC Debt	16,341	17,297	18,259	19,225	20,197	21,174	22,155	23,142	24,135	25,132	26,135	13,571	246,763
AFUDC Equity	39,551	41,866	44,193	46,533	48,884	51,248	53,625	56,014	58,415	60,830	63,257	32,848	597,265
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(17,965,805)	(17,965,805)
CWIP Ending Balance	10,956,476	11,581,203	12,209,218	12,840,538	13,475,183	14,113,168	14,754,511	15,399,230	16,047,343	16,698,868	17,353,822	-	-
Electric General Plant													
CWIP Beginning Balance	63,464	63,798	64,134	-	-	-	-	-	-	-	-	-	63,464
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	98	98	49	-	-	-	-	-	-	-	-	-	245
AFUDC Equity	236	238	119	-	-	-	-	-	-	-	-	-	594
Closings to Plant	-	-	(64,303)	-	-	-	-	-	-	-	-	-	(64,303)
CWIP Ending Balance	63,798	64,134	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Other													
Common General Plant													
CWIP Beginning Balance	3,828,031	4,044,911	4,262,931	4,482,100	4,702,422	4,923,904	5,146,552	5,370,371	5,595,369	6,021,552	6,248,925	6,477,495	3,828,031
CWIP Expenditures	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	400,000	200,000	200,000	200,000	2,600,000
AFUDC Debt	4,935	5,269	5,604	5,941	6,281	6,621	6,964	7,309	7,655	8,003	8,353	4,352	77,286
AFUDC Equity	11,944	12,752	13,564	14,381	15,201	16,026	16,856	17,690	18,528	19,370	20,217	10,534	187,064
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(6,691,805)	(6,691,805)
CWIP Ending Balance	4,044,911	4,262,931	4,482,100	4,702,422	4,923,904	5,146,552	5,370,371	5,595,369	6,021,552	6,248,925	6,477,495	576	576
Common Intangible Plant													
CWIP Beginning Balance	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
Electric Distribution Plant													
CWIP Beginning Balance	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
Electric General Plant													
CWIP Beginning Balance	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Electric Intangible Plant													
CWIP Beginning Balance	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
Electric Other Production Plant													
CWIP Beginning Balance	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
Electric Steam Production Plant													
CWIP Beginning Balance	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
Electric Transmission Plant													
CWIP Beginning Balance	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
Property Services Capital													
Common General Plant													
CWIP Beginning Balance	22,882,385	26,535,570	30,320,996	32,954,020	35,729,910	40,051,815	41,219,215	44,409,869	13,219,818	15,728,976	15,454,908	16,260,082	22,882,385
CWIP Expenditures	4,000,000	4,008,550	2,787,551	2,858,564	4,340,684	3,603,965	3,635,584	3,804,713	2,580,232	2,224,083	2,033,776	2,026,781	37,904,483
AFUDC Debt	37,929	43,638	48,575	52,719	58,166	62,388	65,804	44,731	22,227	23,965	24,430	14,592	499,164
AFUDC Equity	91,803	105,621	117,570	127,600	140,785	151,004	159,273	108,267	53,797	58,006	59,130	35,320	1,208,177
Closings to Plant	(476,547)	(372,383)	(320,672)	(262,993)	(217,730)	(2,649,957)	(670,008)	(35,147,762)	(147,098)	(2,580,122)	(1,312,162)	(16,430,045)	(60,587,478)
CWIP Ending Balance	26,535,570	30,320,996	32,954,020	35,729,910	40,051,815	41,219,215	44,409,869	13,219,818	15,728,976	15,454,908	16,260,082	1,906,730	1,906,730
Electric General Plant													
CWIP Beginning Balance	5,378,603	5,672,478	5,968,232	6,340,609	7,363,142	9,793,886	7,050,440	9,844,752	12,492,125	16,342,334	19,338,172	20,086,207	5,378,603
CWIP Expenditures	265,934	265,934	358,534	1,001,065	2,396,977	2,654,485	2,757,339	3,064,511	3,778,537	3,333,336	2,855,299	2,069,451	24,801,402
AFUDC Debt	8,481	8,934	9,399	10,432	13,102	12,948	12,927	17,176	22,106	27,387	30,398	21,453	194,743
AFUDC Equity	20,529	21,624	22,749	25,251	31,711	31,339	31,288	41,574	53,505	66,287	73,576	51,925	471,358
Closings to Plant	(1,069)	(738)	(18,305)	(14,215)	(11,045)	(5,442,219)	(7,242)	(475,888)	(3,938)	(431,172)	(2,211,237)	(14,992,502)	(23,609,571)
CWIP Ending Balance	5,672,478	5,968,232	6,340,609	7,363,142	9,793,886	7,050,440	9,844,752	12,492,125	16,342,334	19,338,172	20,086,207	7,236,535	7,236,535
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	532,937	419,587	344,551	460,653	479,511	477,901	507,399	1,265,164	1,883,615	2,418,062	2,794,345	3,071,201	532,937
CWIP Expenditures	-	-	308,019	258,019	258,019	308,019	1,258,019	1,298,019	1,368,019	1,318,019	1,298,019	890,000	8,562,171
Closings to Plant	(113,351)	(75,035)	(191,918)	(239,161)	(259,629)	(278,521)	(500,254)	(679,568)	(833,573)	(941,735)	(1,021,163)	(1,190,251)	(6,324,158)
CWIP Ending Balance	419,587	344,551	460,653	479,511	477,901	507,399	1,265,164	1,883,615	2,418,062	2,794,345	3,071,201	2,770,950	2,770,950
Electric General Plant													
CWIP Beginning Balance	40,071	31,166	24,241	18,854	14,664	11,405	8,871	6,900	5,366	4,174	3,246	2,525	40,071
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(8,905)	(6,926)	(5,387)	(4,190)	(3,259)	(2,535)	(1,971)	(1,533)	(1,193)	(928)	(721)	(561)	(38,107)
CWIP Ending Balance	31,166	24,241	18,854	14,664	11,405	8,871	6,900	5,366	4,174	3,246	2,525	1,964	1,964
Remington													
Aging Technology													
Common General Plant													
CWIP Beginning Balance	4,594,075	6,126,844	7,447,506	5,867,606	5,374,554	7,705,160	5,177,489	7,551,236	7,593,269	4,453,995	6,875,970	9,296,180	4,594,075
CWIP Expenditures	1,595,602	1,427,245	2,193,857	2,196,024	2,525,124	2,964,924	2,564,924	2,684,424	2,924,424	2,624,424	2,624,424	2,892,429	29,217,826
Closings to Plant	(62,834)	(106,583)	(3,773,757)	(2,689,076)	(194,519)	(5,492,595)	(191,176)	(2,642,391)	(6,063,698)	(202,448)	(204,214)	(11,709,227)	(33,332,519)
CWIP Ending Balance	6,126,844	7,447,506	5,867,606	5,374,554	7,705,160	5,177,489	7,551,236	7,593,269	4,453,995	6,875,970	9,296,180	479,383	479,383
Common Intangible Plant													
CWIP Beginning Balance	5,397,835	6,655,469	7,272,425	11,251,776	13,299,095	15,352,465	17,411,919	19,477,489	21,549,206	23,627,105	25,767,020	27,536,551	5,397,835
CWIP Expenditures	1,227,868	1,227,868	5,459,126	2,004,258	2,004,258	2,004,258	2,004,258	2,004,258	2,004,258	2,059,953	2,059,953	2,020,625	26,080,941
AFUDC Debt	8,703	9,668	10,829	12,589	14,359	16,137	17,925	19,723	21,530	23,378	24,992	21,334	201,167
AFUDC Equity	21,064	23,400	26,211	30,471	34,754	39,059	43,387	47,737	52,111	56,584	60,492	51,636	486,904
Closings to Plant	-	(643,981)	(1,516,814)	-	-	-	-	-	-	-	(375,906)	(16,865,580)	(19,402,280)
CWIP Ending Balance	6,655,469	7,272,425	11,251,776	13,299,095	15,352,465	17,411,919	19,477,489	21,549,206	23,627,105	25,767,020	27,536,551	12,764,566	12,764,566
Electric General Plant													
CWIP Beginning Balance	16,130,512	17,584,528	19,041,699	21,005,012	22,010,907	24,310,399	25,410,515	25,465,509	26,818,638	27,957,136	29,157,247	30,334,837	16,130,512
CWIP Expenditures	1,396,509	1,393,738	1,992,614	1,494,477	2,198,354	1,241,506	1,198,349	1,234,674	1,115,086	1,072,012	1,044,964	1,041,713	16,423,995
AFUDC Debt	21,198	22,931	25,055	27,202	29,569	31,754	33,172	34,632	36,081	37,452	38,775	40,082	377,904
AFUDC Equity	51,308	55,503	60,643	65,840	71,569	76,856	80,291	83,823	87,331	90,648	93,851	97,015	914,679
Closings to Plant	(15,000)	(15,000)	(115,000)	(581,624)	-	(250,000)	(1,256,818)	-	(100,000)	-	-	-	(2,333,442)
CWIP Ending Balance	17,584,528	19,041,699	21,005,012	22,010,907	24,310,399	25,410,515	25,465,509	26,818,638	27,957,136	29,157,247	30,334,837	31,513,647	31,513,647
Electric Intangible Plant													
CWIP Beginning Balance	5,698,801	6,604,173	7,367,941	8,321,896	5,766,905	6,321,404	5,882,644	6,250,642	6,623,458	6,994,191	7,400,697	7,807,868	5,698,801
CWIP Expenditures	878,897	734,182	921,232	591,756	852,349	582,842	374,510	354,142	351,378	386,482	386,482	2,159,138	8,573,391
AFUDC Debt	7,740	8,650	9,567	7,975	6,030	5,784	5,263	5,460	5,659	5,854	6,049	4,978	79,009
AFUDC Equity	18,735	20,936	23,156	19,302	14,596	14,000	12,739	13,215	13,696	14,170	14,641	12,050	191,234
Closings to Plant	-	-	-	(3,174,023)	(318,476)	(1,041,386)	(24,514)	-	-	-	-	(5,307,074)	(9,865,474)
CWIP Ending Balance	6,604,173	7,367,941	8,321,896	5,766,905	6,321,404	5,882,644	6,250,642	6,623,458	6,994,191	7,400,697	7,807,868	4,676,960	4,676,960

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
AGIS													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Beginning Balance	5,073,237	3,661,472	3,779,450	-	-	-	-	-	-	-	-	-	5,073,237
CWIP Expenditures	216,997	99,863	699,065	70,296	-	1,500,000	-	-	-	-	-	-	2,586,220
AFUDC Debt	5,026	5,296	2,744	-	-	-	-	-	-	-	-	-	13,066
AFUDC Equity	12,165	12,819	6,640	-	-	-	-	-	-	-	-	-	31,625
Closings to Plant	(1,645,953)	-	(4,487,899)	(70,296)	-	(1,500,000)	-	-	-	-	-	-	(7,704,148)
CWIP Ending Balance	3,661,472	3,779,450	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	6,572,170	6,618,457	9,442,488	7,343,389	7,382,045	7,420,904	7,459,967	7,499,237	7,538,713	7,578,396	7,618,289	7,658,392	6,572,170
CWIP Expenditures	11,694	2,789,194	648,032	-	-	-	-	-	-	-	-	-	3,448,920
AFUDC Debt	10,114	10,185	10,746	11,301	11,361	11,421	11,481	11,541	11,602	11,663	11,725	11,786	134,926
AFUDC Equity	24,479	24,652	26,010	27,354	27,498	27,643	27,788	27,935	28,082	28,230	28,378	28,528	326,576
Closings to Plant	-	-	(2,783,888)	-	-	-	-	-	-	-	-	-	(2,783,888)
CWIP Ending Balance	6,618,457	9,442,488	7,343,389	7,382,045	7,420,904	7,459,967	7,499,237	7,538,713	7,578,396	7,618,289	7,658,392	7,698,705	7,698,705
Cyber Security													
Common General Plant													
CWIP Beginning Balance	385,380	522,880	660,380	822,880	1,110,380	1,397,880	1,560,380	1,752,047	1,943,713	1,050,000	1,241,667	1,433,333	385,380
CWIP Expenditures	137,500	137,500	287,500	287,500	287,500	287,500	191,667	191,667	191,667	191,667	191,667	191,667	2,575,000
Closings to Plant	-	-	(125,000)	-	-	(125,000)	-	-	(1,085,380)	-	-	(1,625,000)	(2,960,380)
CWIP Ending Balance	522,880	660,380	822,880	1,110,380	1,397,880	1,560,380	1,752,047	1,943,713	1,050,000	1,241,667	1,433,333	-	-
Common Intangible Plant													
CWIP Beginning Balance	2,449,559	3,368,879	4,270,801	5,248,014	6,213,863	7,181,010	8,136,314	9,089,611	10,051,095	11,012,230	11,973,417	12,878,876	2,449,559
CWIP Expenditures	959,572	956,175	1,040,007	1,033,362	1,036,709	1,025,057	1,021,955	1,028,109	1,025,057	1,021,955	962,902	962,902	12,073,762
AFUDC Debt	1,429	2,617	3,817	5,026	6,238	7,450	8,658	9,874	11,099	12,326	13,511	8,447	90,492
AFUDC Equity	3,459	6,335	9,239	12,164	15,099	18,033	20,956	23,899	26,864	29,833	32,702	20,444	219,027
Closings to Plant	(45,140)	(63,205)	(75,851)	(84,702)	(90,899)	(95,236)	(98,272)	(100,398)	(101,885)	(102,927)	(103,656)	(12,150,473)	(13,112,643)
CWIP Ending Balance	3,368,879	4,270,801	5,248,014	6,213,863	7,181,010	8,136,314	9,089,611	10,051,095	11,012,230	11,973,417	12,878,876	1,720,196	1,720,196
Electric General Plant													
CWIP Beginning Balance	470,000	545,000	620,000	-	-	-	-	-	-	-	-	-	470,000
CWIP Expenditures	75,000	75,000	85,000	-	-	-	-	-	-	-	-	-	235,000
Closings to Plant	-	-	(705,000)	-	-	-	-	-	-	-	-	-	(705,000)
CWIP Ending Balance	545,000	620,000	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	-	41,776	83,773	125,990	168,429	211,092	253,980	297,093	340,433	384,002	427,800	471,828	-
CWIP Expenditures	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	500,000
AFUDC Debt	32	96	161	226	291	357	423	489	556	623	690	379	4,324
AFUDC Equity	78	233	390	547	705	864	1,024	1,184	1,346	1,508	1,671	918	10,467
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(514,791)	(514,791)
CWIP Ending Balance	41,776	83,773	125,990	168,429	211,092	253,980	297,093	340,433	384,002	427,800	471,828	-	-
Emergent Demand													
Common General Plant													
CWIP Beginning Balance	(6,761,371)	(5,491,810)	(4,349,204)	(3,320,860)	(2,395,349)	(1,562,390)	(812,727)	(138,030)	469,197	1,015,702	1,507,556	1,950,225	(6,761,371)
CWIP Expenditures	659,360	659,360	659,360	659,360	659,360	659,360	659,360	659,360	659,360	659,360	659,360	659,360	7,912,324
Closings to Plant	610,201	483,245	368,984	266,150	173,599	90,303	15,337	(52,133)	(112,856)	(167,506)	(216,692)	(260,959)	1,197,674
CWIP Ending Balance	(5,491,810)	(4,349,204)	(3,320,860)	(2,395,349)	(1,562,390)	(812,727)	(138,030)	469,197	1,015,702	1,507,556	1,950,225	2,348,627	2,348,627
Common Intangible Plant													
CWIP Beginning Balance	(2,819,515)	(1,888,090)	(1,236,092)	(779,694)	(460,215)	(236,580)	(80,035)	29,546	106,253	159,948	197,534	223,844	(2,819,515)
CWIP Expenditures	122,244	122,244	122,244	122,244	122,244	122,244	122,244	122,244	122,244	122,244	122,244	122,244	1,466,925
Closings to Plant	809,181	529,754	334,155	197,235	101,391	34,301	(12,663)	(45,537)	(68,549)	(84,657)	(95,933)	(103,826)	1,594,852
CWIP Ending Balance	(1,888,090)	(1,236,092)	(779,694)	(460,215)	(236,580)	(80,035)	29,546	106,253	159,948	197,534	223,844	242,262	242,262
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	15,398,731	15,607,616	17,335,216	17,558,858	17,770,761	17,990,074	18,942,923	19,157,928	19,386,760	21,305,284	21,523,472	21,749,103	15,398,731
CWIP Expenditures	154,939	1,672,681	167,711	154,939	161,325	893,817	154,939	167,711	1,856,324	154,939	161,325	636,325	6,336,979
AFUDC Debt	15,772	16,056	16,352	16,654	16,953	17,259	17,561	17,870	18,185	18,492	18,800	19,116	209,069
AFUDC Equity	38,174	38,862	39,578	40,310	41,034	41,773	42,504	43,252	44,014	44,758	45,505	46,267	506,032
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(725,000)	(725,000)
CWIP Ending Balance	15,607,616	17,335,216	17,558,858	17,770,761	17,990,074	18,942,923	19,157,928	19,386,760	21,305,284	21,523,472	21,749,103	21,725,811	21,725,811
Common Intangible Plant													
CWIP Beginning Balance	1,236,914	3,180,060	5,151,628	7,204,519	9,107,900	11,144,935	12,848,971	14,878,723	16,034,397	17,731,937	19,510,806	20,165,390	1,236,914
CWIP Expenditures	2,570,144	2,086,481	2,155,911	2,079,541	2,036,487	2,030,256	2,021,135	2,019,967	2,017,495	2,237,644	1,866,252	1,779,748	24,901,063
AFUDC Debt	3,236	6,027	8,847	11,574	14,256	16,809	19,341	21,503	23,499	26,050	27,660	18,824	197,623
AFUDC Equity	7,832	14,589	21,413	28,013	34,504	40,684	46,812	52,045	56,877	63,050	66,948	45,562	478,328
Closings to Plant	(638,065)	(135,530)	(133,280)	(215,746)	(48,213)	(383,713)	(57,535)	(937,840)	(400,331)	(547,875)	(1,306,276)	(16,306,619)	(21,111,022)
CWIP Ending Balance	3,180,060	5,151,628	7,204,519	9,107,900	11,144,935	12,848,971	14,878,723	16,034,397	17,731,937	19,510,806	20,165,390	5,702,906	5,702,906

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2022 Year-to-date
Electric General Plant													
CWIP Beginning Balance	-	301,287	602,573	62,500	83,333	104,167	125,000	145,833	166,667	187,500	208,333	229,167	-
CWIP Expenditures	301,621	301,620	301,620	301,287	301,287	301,287	20,833	20,833	20,833	20,833	20,833	20,833	1,933,720
Closings to Plant	(334)	(333)	(841,693)	(280,453)	(280,453)	(280,453)	-	-	-	-	-	-	(1,683,720)
CWIP Ending Balance	301,287	602,573	62,500	83,333	104,167	125,000	145,833	166,667	187,500	208,333	229,167	250,000	250,000
Electric Intangible Plant													
CWIP Beginning Balance	3,630,043	4,799,009	5,935,946	7,078,148	8,225,644	9,130,647	10,238,465	11,351,395	12,469,465	13,592,701	14,721,130	15,730,663	3,630,043
CWIP Expenditures	1,147,198	1,109,833	1,109,833	1,109,833	1,109,833	1,060,918	1,060,918	1,060,918	1,060,918	1,060,918	1,003,502	918,730	12,813,347
AFUDC Debt	6,364	7,924	9,464	11,011	12,396	13,712	15,207	16,709	18,220	19,738	21,216	20,493	172,454
AFUDC Equity	15,404	19,180	22,906	26,652	30,004	33,189	36,806	40,443	44,099	47,774	51,350	49,601	417,407
Closings to Plant	-	-	-	-	(247,229)	-	-	-	-	-	(66,535)	(4,431,576)	(4,745,340)
CWIP Ending Balance	4,799,009	5,935,946	7,078,148	8,225,644	9,130,647	10,238,465	11,351,395	12,469,465	13,592,701	14,721,130	15,730,663	12,287,912	12,287,912
Customer													
Common General Plant													
CWIP Beginning Balance	-	1,000	2,000	-	1,000	2,000	-	1,000	2,000	-	-	-	-
CWIP Expenditures	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	-	-	-	9,000
Closings to Plant	-	-	(3,000)	-	-	(3,000)	-	-	(3,000)	-	-	-	(9,000)
CWIP Ending Balance	1,000	2,000	-	1,000	2,000	-	1,000	2,000	-	-	-	-	-
Common Intangible Plant													
CWIP Beginning Balance	1,376,369	1,850,866	2,281,855	2,729,857	3,089,251	3,421,062	3,729,912	4,037,279	4,347,076	4,168,624	4,406,597	4,634,122	1,376,369
CWIP Expenditures	526,554	526,269	572,273	515,041	514,375	514,395	532,483	551,513	550,069	533,158	514,855	514,875	6,365,860
AFUDC Debt	2,374	2,824	3,253	3,628	3,913	4,159	4,387	4,615	4,488	4,271	4,383	2,347	44,642
AFUDC Equity	5,747	6,835	7,874	8,781	9,471	10,067	10,618	11,171	10,862	10,338	10,609	5,680	108,053
Closings to Plant	(60,178)	(104,940)	(135,399)	(168,055)	(195,948)	(219,772)	(240,121)	(257,502)	(743,870)	(309,794)	(302,322)	(5,157,024)	(7,894,925)
CWIP Ending Balance	1,850,866	2,281,855	2,729,857	3,089,251	3,421,062	3,729,912	4,037,279	4,347,076	4,168,624	4,406,597	4,634,122	-	-

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Benson													
Asset Renewal													
Electric General Plant													
CWIP Beginning Balance	4,358,430	4,872,809	4,897,815	5,595,932	6,123,313	6,131,323	7,612,490	7,976,258	8,413,677	9,642,274	9,923,671	9,970,516	4,358,430
CWIP Expenditures	512,000	22,000	1,392,010	522,000	2,000	1,927,010	354,000	427,000	1,897,010	267,200	32,000	2,171,810	9,526,040
AFUDC Debt	705	891	1,156	1,595	1,782	2,249	2,896	3,089	3,563	4,209	4,401	2,534	29,071
AFUDC Equity	1,674	2,115	2,743	3,785	4,228	5,336	6,872	7,330	8,453	9,987	10,444	6,013	68,981
Closings to Plant	-	-	(697,791)	-	-	(453,429)	-	-	(680,429)	-	-	(7,150,873)	(8,982,522)
CWIP Ending Balance	4,872,809	4,897,815	5,595,932	6,123,313	6,131,323	7,612,490	7,976,258	8,413,677	9,642,274	9,923,671	9,970,516	5,000,000	5,000,000
Electric Transmission Plant													
CWIP Beginning Balance	54,149,539	58,612,329	58,903,534	44,955,238	51,562,565	58,980,347	42,904,534	46,864,270	56,310,272	50,025,768	63,996,200	76,415,050	54,149,539
CWIP Expenditures	9,021,363	6,662,374	22,427,803	7,455,108	9,008,969	19,575,628	10,225,675	10,750,200	23,852,057	14,710,766	14,779,491	19,672,291	168,141,725
AFUDC Debt	82,464	86,103	79,101	70,632	80,835	78,062	66,129	75,636	82,407	83,347	102,673	89,835	977,223
AFUDC Equity	195,676	204,309	187,696	167,599	191,809	185,230	156,915	179,472	195,539	197,771	243,629	213,166	2,318,812
Closings to Plant	(4,836,713)	(6,661,582)	(36,642,895)	(1,086,012)	(1,863,831)	(35,914,733)	(6,488,983)	(1,559,306)	(30,414,507)	(1,021,451)	(2,706,943)	(57,163,455)	(186,360,412)
CWIP Ending Balance	58,612,329	58,903,534	44,955,238	51,562,565	58,980,347	42,904,534	46,864,270	56,310,272	50,025,768	63,996,200	76,415,050	39,226,888	39,226,888
Comm Infrastructure													
Electric General Plant													
CWIP Beginning Balance	56,122	1,450,434	3,065,153	72,058	1,735,129	3,401,373	-	1,684,590	3,377,469	-	2,589,993	5,192,731	56,122
CWIP Expenditures	1,455,614	1,604,960	1,628,702	1,658,636	1,653,636	1,663,636	1,702,353	1,690,455	2,658,636	2,583,636	2,583,636	2,917,000	23,800,900
AFUDC Debt	1,096	3,286	2,877	1,315	3,738	3,088	1,226	3,684	3,434	1,885	5,664	4,852	36,144
AFUDC Equity	2,601	7,797	6,827	3,121	8,869	7,328	2,909	8,741	8,147	4,472	13,439	11,513	85,765
Closings to Plant	(65,000)	(1,324)	(4,631,501)	-	-	(5,075,424)	(21,898)	(10,000)	(6,047,686)	-	-	(8,126,097)	(23,978,931)
CWIP Ending Balance	1,450,434	3,065,153	72,058	1,735,129	3,401,373	-	1,684,590	3,377,469	-	2,589,993	5,192,731	-	-
Electric Transmission Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	318,500	-	-	-	-	-	-	-	-	-	-	-	318,500
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(318,500)	-	-	-	-	-	-	-	-	-	-	-	(318,500)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnection													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	880,387	984,823	1,089,773	2,976,254	3,091,004	3,206,319	4,649,072	4,772,054	4,895,641	7,177,895	8,114,150	9,055,012	880,387
CWIP Expenditures	99,858	99,858	3,349,858	99,858	99,858	3,349,858	99,858	99,858	4,648,721	898,721	898,721	5,181,607	18,926,634
AFUDC Debt	1,357	1,510	3,461	4,415	4,583	6,220	6,856	7,035	9,336	11,128	12,494	12,137	80,533
AFUDC Equity	3,221	3,582	8,213	10,477	10,874	14,759	16,268	16,694	22,154	26,406	29,647	28,800	191,094
Closings to Plant	-	-	(1,475,050)	-	-	(1,928,084)	-	-	(2,397,958)	-	-	(8,014,858)	(13,815,950)
CWIP Ending Balance	984,823	1,089,773	2,976,254	3,091,004	3,206,319	4,649,072	4,772,054	4,895,641	7,177,895	8,114,150	9,055,012	6,262,697	6,262,697
Regional Expansion													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	9,014,492	10,567,455	11,125,600	15,469,076	15,800,726	17,151,205	20,639,762	22,166,328	23,169,703	27,700,161	28,169,591	28,857,963	9,014,492
CWIP Expenditures	1,504,900	504,900	4,278,200	254,900	1,269,600	3,395,800	1,421,500	892,100	4,405,600	332,300	548,400	4,626,700	23,434,900
AFUDC Debt	14,250	15,786	19,353	22,755	23,979	27,501	31,150	32,991	37,018	40,657	41,500	45,479	352,421
AFUDC Equity	33,813	37,459	45,922	53,995	56,900	65,256	73,915	78,284	87,840	96,473	98,472	107,915	836,244
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	10,567,455	11,125,600	15,469,076	15,800,726	17,151,205	20,639,762	22,166,328	23,169,703	27,700,161	28,169,591	28,857,963	33,638,057	33,638,057

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Reliability Requirement													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	17,999,090	22,812,870	24,558,722	29,209,202	31,215,923	29,190,338	21,842,133	24,770,551	25,027,824	27,282,060	26,918,106	28,202,397	17,999,090
CWIP Expenditures	6,213,609	1,629,580	5,519,509	1,858,410	2,693,610	6,700,261	2,847,829	140,845	3,126,844	1,049,210	1,153,900	5,543,411	38,477,018
AFUDC Debt	29,699	34,473	39,493	43,972	44,047	38,825	33,920	36,239	38,431	39,459	40,112	43,401	462,070
AFUDC Equity	70,472	81,799	93,710	104,339	104,517	92,126	80,488	85,989	91,192	93,630	95,179	102,984	1,096,426
Closings to Plant	(1,500,000)	-	(1,002,231)	-	(4,867,759)	(14,179,416)	(33,820)	(5,800)	(1,002,231)	(1,546,253)	(4,900)	(3,510,602)	(27,653,013)
CWIP Ending Balance	22,812,870	24,558,722	29,209,202	31,215,923	29,190,338	21,842,133	24,770,551	25,027,824	27,282,060	26,918,106	28,202,397	30,381,591	30,381,591
Security\Resiliency													
Electric General Plant													
CWIP Beginning Balance	275,946	852,436	1,004,194	678,968	1,282,983	1,928,064	3,111,075	3,776,180	5,485,112	5,732,286	6,361,169	7,031,240	275,946
CWIP Expenditures	573,721	147,200	137,201	599,200	637,200	1,637,200	648,201	1,686,200	686,200	599,200	637,200	137,201	8,125,924
AFUDC Debt	821	1,351	1,226	1,428	2,337	3,668	5,012	6,740	8,164	8,801	9,746	5,179	54,471
AFUDC Equity	1,948	3,206	2,908	3,388	5,545	8,703	11,893	15,992	19,372	20,882	23,125	12,290	129,252
Closings to Plant	-	-	(466,561)	-	-	(466,561)	-	-	(466,561)	-	-	(7,185,910)	(8,585,593)
CWIP Ending Balance	852,436	1,004,194	678,968	1,282,983	1,928,064	3,111,075	3,776,180	5,485,112	5,732,286	6,361,169	7,031,240	-	-
Electric Intangible Plant													
CWIP Beginning Balance	-	85,460	171,340	-	85,460	171,340	-	85,460	171,340	-	85,460	171,340	-
CWIP Expenditures	85,250	85,250	85,250	85,250	85,250	85,250	85,250	85,250	85,250	85,250	85,250	85,250	1,023,000
AFUDC Debt	62	187	156	62	187	156	62	187	156	62	187	156	1,621
AFUDC Equity	148	443	370	148	443	370	148	443	370	148	443	370	3,845
Closings to Plant	-	-	(257,117)	-	-	(257,117)	-	-	(257,117)	-	-	(257,117)	(1,028,466)
CWIP Ending Balance	85,460	171,340	-	85,460	171,340	-	85,460	171,340	-	85,460	171,340	-	-
Electric Transmission Plant													
CWIP Beginning Balance	3,624,635	4,805,237	3,181,385	4,337,010	4,840,128	10,179,403	12,131,334	14,910,116	16,700,113	19,135,240	21,447,258	23,269,423	3,624,635
CWIP Expenditures	1,159,911	1,289,911	1,137,171	2,002,410	5,714,910	1,897,170	2,712,410	1,712,411	2,347,170	2,212,410	1,712,410	2,349,660	26,247,954
AFUDC Debt	6,134	5,958	5,471	6,790	10,930	16,236	19,678	23,003	26,078	29,532	32,541	17,873	200,225
AFUDC Equity	14,556	14,137	12,982	16,111	25,935	38,525	46,694	54,583	61,879	70,076	77,215	42,411	475,105
Closings to Plant	-	(2,933,858)	-	(1,522,193)	(412,500)	-	-	-	-	-	-	(25,622,330)	(30,490,880)
CWIP Ending Balance	4,805,237	3,181,385	4,337,010	4,840,128	10,179,403	12,131,334	14,910,116	16,700,113	19,135,240	21,447,258	23,269,423	57,038	57,038
Bloch													
AGIS													
Electric Distribution Plant													
CWIP Beginning Balance	506,641	591,144	676,062	761,398	847,154	933,333	1,019,935	1,106,963	1,194,420	1,282,307	1,370,626	1,459,381	506,641
CWIP Expenditures	10,196,763	9,927,416	9,927,416	10,196,763	9,927,416	9,927,416	10,196,763	9,927,416	9,927,416	10,196,763	7,521,160	9,521,160	117,393,869
AFUDC Debt	1,414	1,537	1,661	1,786	1,911	2,037	2,163	2,290	2,418	2,546	2,310	3,169	25,242
AFUDC Equity	3,356	3,648	3,942	4,238	4,534	4,833	5,133	5,434	5,737	6,041	5,481	7,519	59,895
Closings to Plant	(10,117,030)	(9,847,684)	(9,847,684)	(10,117,030)	(9,847,684)	(9,847,684)	(10,117,030)	(9,847,684)	(9,847,684)	(10,117,030)	(7,440,197)	(9,442,657)	(116,437,075)
CWIP Ending Balance	591,144	676,062	761,398	847,154	933,333	1,019,935	1,106,963	1,194,420	1,282,307	1,370,626	1,459,381	1,548,571	1,548,571
Electric General Plant													
CWIP Beginning Balance	7,939,447	8,944,318	9,745,549	10,673,703	11,777,741	12,888,277	14,050,166	15,139,780	16,236,982	17,350,407	19,060,137	20,293,382	7,939,447
CWIP Expenditures	1,377,683	851,102	962,289	1,127,943	1,127,793	1,200,149	1,116,201	1,116,201	1,127,493	1,720,592	1,242,024	2,214,930	15,184,400
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(372,812)	(49,871)	(34,134)	(23,906)	(17,257)	(38,260)	(26,587)	(19,000)	(14,068)	(10,862)	(8,779)	(1,007,424)	(1,622,959)
CWIP Ending Balance	8,944,318	9,745,549	10,673,703	11,777,741	12,888,277	14,050,166	15,139,780	16,236,982	17,350,407	19,060,137	20,293,382	21,500,888	21,500,888
Electric Intangible Plant													
CWIP Beginning Balance	3,619,114	3,846,547	4,075,099	4,304,776	4,585,707	4,868,019	5,151,722	5,436,820	5,913,788	6,393,104	6,874,779	7,296,671	3,619,114
CWIP Expenditures	209,109	209,109	209,109	259,109	259,109	259,109	259,109	449,109	449,109	449,109	387,109	521,809	3,920,008
AFUDC Debt	5,433	5,765	6,098	6,470	6,880	7,291	7,705	8,260	8,956	9,655	10,313	10,367	93,192
AFUDC Equity	12,891	13,679	14,470	15,352	16,324	17,302	18,284	19,600	21,251	22,910	24,471	24,599	221,132
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(944,702)	(944,702)
CWIP Ending Balance	3,846,547	4,075,099	4,304,776	4,585,707	4,868,019	5,151,722	5,436,820	5,913,788	6,393,104	6,874,779	7,296,671	6,908,744	6,908,744
Asset Health & Reliability													
Electric Distribution Plant													
CWIP Beginning Balance	44,828,224	47,317,172	49,791,215	52,330,125	55,131,132	58,524,749	53,036,194	56,705,726	52,460,631	54,915,797	56,095,898	56,217,887	44,828,224
CWIP Expenditures	15,521,650	15,521,650	15,601,255	15,874,785	16,473,375	16,589,875	17,399,775	17,399,775	16,818,405	15,084,305	13,748,555	15,456,155	191,489,560
AFUDC Debt	36,344	39,897	43,463	47,264	51,694	50,420	48,146	46,783	44,639	47,371	49,003	49,962	554,987
AFUDC Equity	86,238	94,671	103,132	112,151	122,662	119,640	114,244	111,009	105,922	112,405	116,277	118,553	1,316,905
Closings to Plant	(13,155,284)	(13,182,176)	(13,208,940)	(13,233,193)	(13,254,113)	(22,248,490)	(13,892,633)	(21,802,663)	(14,513,800)	(14,063,979)	(13,791,847)	(14,236,314)	(180,583,432)
CWIP Ending Balance	47,317,172	49,791,215	52,330,125	55,131,132	58,524,749	53,036,194	56,705,726	52,460,631	54,915,797	56,095,898	56,217,887	57,606,243	57,606,243

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Electric General Plant													
CWIP Beginning Balance	32,836	34,197	35,154	35,827	36,300	36,632	36,866	38,420	39,512	40,280	39,430	38,833	32,836
CWIP Expenditures	15,847	15,847	15,847	15,847	15,847	15,847	17,828	17,828	17,828	15,847	15,847	17,828	198,088
AFUDC Debt	51	52	53	54	55	55	57	59	60	60	59	59	674
AFUDC Equity	120	124	127	129	130	131	135	139	143	142	139	141	1,599
Closings to Plant	(14,656)	(15,066)	(15,354)	(15,557)	(15,700)	(15,800)	(16,466)	(16,934)	(17,263)	(16,899)	(16,643)	(17,058)	(193,394)
CWIP Ending Balance	34,197	35,154	35,827	36,300	36,632	36,866	38,420	39,512	40,280	39,430	38,833	39,802	39,802
Capacity													
Electric Distribution Plant													
CWIP Beginning Balance	9,609,099	11,430,565	13,234,048	15,474,947	10,387,602	12,668,515	15,565,773	17,682,784	19,768,960	21,620,859	10,483,992	10,558,440	9,609,099
CWIP Expenditures	3,206,239	3,206,239	3,651,304	3,788,194	3,724,234	4,683,079	3,599,984	3,599,984	3,384,464	3,052,414	1,595,119	1,782,134	39,273,388
AFUDC Debt	12,176	14,816	17,761	15,847	13,647	17,441	21,031	24,008	26,811	20,496	12,033	10,807	206,872
AFUDC Equity	28,891	35,157	42,143	37,602	32,383	41,385	49,903	56,967	63,618	48,634	28,552	25,643	490,878
Closings to Plant	(1,425,839)	(1,452,730)	(1,470,308)	(8,928,988)	(1,489,352)	(1,844,647)	(1,553,907)	(1,594,783)	(1,622,993)	(14,258,411)	(1,561,256)	(3,633,021)	(40,836,235)
CWIP Ending Balance	11,430,565	13,234,048	15,474,947	10,387,602	12,668,515	15,565,773	17,682,784	19,768,960	21,620,859	10,483,992	10,558,440	8,744,002	8,744,002
Electric General Plant													
CWIP Beginning Balance	-	56,000	112,000	168,000	224,000	308,000	392,000	476,000	560,000	630,000	-	-	-
CWIP Expenditures	56,000	56,000	56,000	56,000	84,000	84,000	84,000	84,000	70,000	70,000	-	-	700,000
Closings to Plant	-	-	-	-	-	-	-	-	-	(700,000)	-	-	(700,000)
CWIP Ending Balance	56,000	112,000	168,000	224,000	308,000	392,000	476,000	560,000	630,000	-	-	-	-
Electric Vehicles													
Electric Distribution Plant													
CWIP Beginning Balance	18,716,062	16,689,617	15,264,340	14,261,889	13,556,831	13,060,940	12,712,164	12,909,259	13,047,390	13,144,197	12,769,644	12,506,534	18,716,062
CWIP Expenditures	5,048,000	5,048,000	5,048,000	5,048,000	5,048,000	5,048,000	5,679,000	5,679,000	5,679,000	5,048,000	5,048,000	5,679,000	63,100,000
AFUDC Debt	23,199	20,334	18,319	16,903	15,908	15,208	15,012	15,082	15,131	14,869	14,478	14,499	198,943
AFUDC Equity	55,049	48,249	43,469	40,109	37,747	36,087	35,622	35,787	35,903	35,283	34,354	34,405	472,063
Closings to Plant	(7,152,693)	(6,541,860)	(6,112,238)	(5,810,070)	(5,597,546)	(5,448,070)	(5,532,540)	(5,591,739)	(5,633,227)	(5,472,705)	(5,359,943)	(5,470,331)	(69,722,962)
CWIP Ending Balance	16,689,617	15,264,340	14,261,889	13,556,831	13,060,940	12,712,164	12,909,259	13,047,390	13,144,197	12,769,644	12,506,534	12,764,106	12,764,106
Mandates													
Electric Distribution Plant													
CWIP Beginning Balance	5,565,356	5,738,185	5,884,058	6,004,965	6,104,021	6,184,561	6,249,712	6,508,883	6,696,644	6,836,083	6,735,069	6,670,813	5,565,356
CWIP Expenditures	2,427,326	2,427,326	2,427,326	2,427,326	2,427,326	2,427,326	2,730,743	2,730,743	2,730,743	2,427,326	2,427,326	2,730,743	30,341,580
AFUDC Debt	3,607	3,617	3,625	3,631	3,636	3,640	3,694	3,776	3,843	3,846	3,809	3,829	44,553
AFUDC Equity	8,558	8,582	8,601	8,616	8,628	8,638	8,764	8,961	9,118	9,127	9,039	9,086	105,718
Closings to Plant	(2,266,662)	(2,293,652)	(2,318,644)	(2,340,516)	(2,359,051)	(2,374,454)	(2,484,030)	(2,555,718)	(2,604,265)	(2,541,314)	(2,504,429)	(2,579,289)	(29,222,023)
CWIP Ending Balance	5,738,185	5,884,058	6,004,965	6,104,021	6,184,561	6,249,712	6,508,883	6,696,644	6,836,083	6,735,069	6,670,813	6,835,183	6,835,183
New Business													
Electric Distribution Plant													
CWIP Beginning Balance	7,214,820	7,095,322	7,030,020	6,994,478	6,975,256	6,964,964	6,959,539	7,305,881	7,505,168	7,621,755	7,342,292	7,184,359	7,214,820
CWIP Expenditures	4,919,609	4,919,609	4,919,609	4,919,609	4,919,609	4,919,609	5,534,561	5,534,561	5,534,561	4,919,609	4,919,609	5,534,561	61,495,116
AFUDC Debt	3	2	1	1	1	0	0	0	0	0	0	0	9
AFUDC Equity	7	5	3	2	2	1	1	1	0	0	0	0	22
Closings to Plant	(5,039,116)	(4,984,918)	(4,955,155)	(4,938,834)	(4,929,904)	(4,925,035)	(5,188,220)	(5,335,275)	(5,417,975)	(5,199,072)	(5,077,542)	(5,275,635)	(61,266,682)
CWIP Ending Balance	7,095,322	7,030,020	6,994,478	6,975,256	6,964,964	6,959,539	7,305,881	7,505,168	7,621,755	7,342,292	7,184,359	7,443,285	7,443,285
Solar													
Electric Distribution Plant													
CWIP Beginning Balance	(1,447)	(1,157)	(927)	(744)	(598)	(482)	(389)	(315)	(256)	(209)	(170)	(140)	(1,447)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	6	5	4	3	2	2	2	1	1	1	1	1	27
AFUDC Equity	14	11	9	7	6	5	4	3	2	2	2	1	64
Closings to Plant	271	215	171	136	108	86	69	55	44	35	28	23	1,241
CWIP Ending Balance	(1,157)	(927)	(744)	(598)	(482)	(389)	(315)	(256)	(209)	(170)	(140)	(115)	(115)
Electric General Plant													
CWIP Beginning Balance	(13,357)	(10,686)	(8,549)	(6,839)	(5,471)	(4,377)	(3,502)	(2,801)	(2,241)	(1,793)	(1,434)	(1,147)	(13,357)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	2,671	2,137	1,710	1,368	1,094	875	700	560	448	359	287	229	12,439
CWIP Ending Balance	(10,686)	(8,549)	(6,839)	(5,471)	(4,377)	(3,502)	(2,801)	(2,241)	(1,793)	(1,434)	(1,147)	(918)	(918)

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	71,178	69,615	68,521	67,755	67,219	66,844	66,581	68,871	70,474	71,596	69,908	68,726	71,178
CWIP Expenditures	28,272	28,272	28,272	28,272	28,272	28,272	31,806	31,806	31,806	28,272	28,272	31,806	353,400
Closings to Plant	(29,835)	(29,366)	(29,038)	(28,808)	(28,647)	(28,535)	(29,516)	(30,203)	(30,684)	(29,960)	(29,454)	(30,159)	(354,206)
CWIP Ending Balance	69,615	68,521	67,755	67,219	66,844	66,581	68,871	70,474	71,596	69,908	68,726	70,372	70,372
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant													
CWIP Beginning Balance	2,227,395	2,234,854	2,243,289	2,252,425	2,262,066	2,272,078	2,282,364	2,295,660	2,308,277	2,320,437	2,329,492	2,339,190	2,227,395
CWIP Expenditures	32,000	32,000	32,000	32,000	32,000	32,000	36,000	36,000	36,000	32,000	32,000	36,000	400,000
AFUDC Debt	3,126	3,141	3,157	3,172	3,188	3,204	3,219	3,235	3,251	3,267	3,283	3,299	38,542
AFUDC Equity	7,417	7,454	7,490	7,527	7,564	7,601	7,639	7,676	7,714	7,752	7,790	7,829	91,455
Closings to Plant	(35,084)	(34,159)	(33,511)	(33,058)	(32,741)	(32,518)	(33,563)	(34,294)	(34,806)	(33,964)	(33,375)	(34,162)	(405,236)
CWIP Ending Balance	2,234,854	2,243,289	2,252,425	2,262,066	2,272,078	2,282,364	2,295,660	2,308,277	2,320,437	2,329,492	2,339,190	2,352,156	2,352,156
Electric General Plant													
CWIP Beginning Balance	5,488,896	5,494,469	5,511,960	5,540,134	5,652,189	5,785,140	5,908,177	6,174,863	6,409,339	6,577,134	6,658,944	6,729,253	5,488,896
CWIP Expenditures	1,216,579	1,216,579	1,217,173	1,302,874	1,331,443	1,392,399	1,522,056	1,522,056	1,475,481	1,366,670	1,337,983	1,836,569	16,737,862
AFUDC Debt	7,264	7,288	7,326	7,436	7,619	7,813	8,092	8,434	8,709	8,882	9,006	9,434	97,304
AFUDC Equity	17,237	17,294	17,384	17,644	18,079	18,540	19,201	20,012	20,666	21,075	21,371	22,386	230,888
Closings to Plant	(1,235,507)	(1,223,670)	(1,213,710)	(1,215,899)	(1,224,190)	(1,295,716)	(1,282,663)	(1,316,026)	(1,337,061)	(1,314,816)	(1,298,051)	(1,399,514)	(15,356,822)
CWIP Ending Balance	5,494,469	5,511,960	5,540,134	5,652,189	5,785,140	5,908,177	6,174,863	6,409,339	6,577,134	6,658,944	6,729,253	7,198,128	7,198,128
Capra													
Coal													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	16,667	16,667	18,917	21,917	24,917	27,917	30,917	33,917	39,167	46,667	40,667	31,667	350,000
Closings to Plant	(16,667)	(16,667)	(18,917)	(21,917)	(24,917)	(27,917)	(30,917)	(33,917)	(39,167)	(46,667)	(40,667)	(31,667)	(350,000)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant													
CWIP Beginning Balance	3,112,437	3,737,689	4,458,311	5,579,128	5,649,245	3,237,710	3,454,835	4,192,281	4,548,901	4,659,196	2,329,604	2,171,660	3,112,437
CWIP Expenditures	684,871	779,646	1,127,473	1,191,748	1,365,026	994,516	1,080,576	729,703	692,847	624,185	924,986	1,975,004	12,170,579
AFUDC Debt	4,960	5,940	7,280	8,170	6,637	4,884	5,604	6,348	6,719	5,184	3,306	3,953	68,986
AFUDC Equity	11,770	14,094	17,275	19,387	15,748	11,589	13,298	15,063	15,943	12,301	7,844	9,381	163,693
Closings to Plant	(76,349)	(79,058)	(31,211)	(1,149,188)	(3,798,947)	(793,864)	(362,031)	(394,496)	(605,213)	(2,971,261)	(1,094,081)	(984,101)	(12,339,799)
CWIP Ending Balance	3,737,689	4,458,311	5,579,128	5,649,245	3,237,710	3,454,835	4,192,281	4,548,901	4,659,196	2,329,604	2,171,660	3,175,896	3,175,896
Hydro													
Electric General Plant													
CWIP Expenditures	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
Closings to Plant	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(15,000)
Electric Hydro Production Plant													
CWIP Beginning Balance	281,403	287,798	294,225	300,683	307,171	313,681	325,246	336,868	348,545	360,281	382,085	404,005	281,403
CWIP Expenditures	5,000	5,000	5,000	5,000	5,000	10,000	10,000	10,000	10,000	20,000	20,000	35,000	140,000
AFUDC Debt	414	424	433	442	452	465	482	499	516	540	572	615	5,853
AFUDC Equity	983	1,005	1,027	1,050	1,072	1,103	1,143	1,184	1,224	1,282	1,357	1,459	13,889
Closings to Plant	(2)	(2)	(2)	(4)	(14)	(3)	(3)	(5)	(5)	(17)	(10)	(7)	(74)
CWIP Ending Balance	287,798	294,225	300,683	307,171	313,681	325,246	336,868	348,545	360,281	382,085	404,005	441,072	441,072
Intermediate													
Electric General Plant													
CWIP Beginning Balance	10,000	10,000	10,455	23,159	35,864	48,568	73,153	76,314	84,809	95,063	105,899	116,925	10,000
CWIP Expenditures	25,302	30,452	48,142	65,708	66,508	98,308	24,958	26,258	48,458	203,458	26,858	24,058	688,470
Closings to Plant	(25,302)	(29,997)	(35,437)	(53,004)	(53,804)	(73,724)	(21,797)	(17,764)	(38,204)	(192,623)	(15,832)	(12,968)	(570,455)
CWIP Ending Balance	10,000	10,455	23,159	35,864	48,568	73,153	76,314	84,809	95,063	105,899	116,925	128,015	128,015
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Other Production Plant													
CWIP Beginning Balance	6,937,446	11,599,792	12,916,647	6,209,892	4,306,096	4,259,696	5,356,241	5,998,428	6,798,752	7,820,865	5,395,116	6,208,096	6,937,446
CWIP Expenditures	4,652,683	1,288,006	1,870,019	4,755,102	1,011,140	1,185,415	726,482	1,201,648	1,557,522	1,685,255	2,813,382	1,283,512	24,030,167
AFUDC Debt	13,490	17,842	14,359	7,989	6,279	7,003	8,270	9,339	10,698	9,803	8,535	9,352	122,960
AFUDC Equity	32,010	42,336	34,072	18,957	14,899	16,618	19,623	22,161	25,384	23,260	20,253	22,192	291,765
Closings to Plant	(35,836)	(31,329)	(8,625,206)	(6,685,844)	(1,078,717)	(112,491)	(112,189)	(432,824)	(571,491)	(4,144,067)	(2,029,191)	(950,936)	(24,810,120)
CWIP Ending Balance	11,599,792	12,916,647	6,209,892	4,306,096	4,259,696	5,356,241	5,998,428	6,798,752	7,820,865	5,395,116	6,208,096	6,572,217	6,572,217

Northern States Power Company
CWIP by Witness, Functional Class, and Category

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 32 of 49

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Solar													
Electric Other Production Plant													
CWIP Beginning Balance	189,331,718	201,078,094	212,882,275	232,642,622	258,092,806	278,619,572	310,180,919	340,982,350	371,935,355	402,521,036	158,978,710	170,861,949	189,331,718
CWIP Expenditures	10,788,131	10,788,131	18,666,824	24,245,693	19,209,426	30,116,160	29,203,176	29,203,176	28,684,808	28,684,808	21,845,982	28,145,744	279,582,058
AFUDC Debt	284,105	301,243	324,213	357,113	390,571	428,476	473,858	518,797	563,579	414,552	240,028	255,524	4,552,058
AFUDC Equity	674,141	714,807	769,311	847,378	926,769	1,016,712	1,124,397	1,231,032	1,337,294	983,674	569,553	606,322	10,801,387
Closings to Plant	-	-	-	-	-	-	-	-	-	(273,625,359)	(10,772,325)	(19,597,187)	(303,994,870)
CWIP Ending Balance	201,078,094	212,882,275	232,642,622	258,092,806	278,619,572	310,180,919	340,982,350	371,935,355	402,521,036	158,978,710	170,861,949	180,272,352	180,272,352
Electric Transmission Plant													
CWIP Beginning Balance	123,861	134,495	145,182	155,921	166,713	177,558	188,456	199,408	210,414	221,474	232,588	243,758	123,861
CWIP Expenditures	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	120,000
AFUDC Debt	188	204	219	235	251	266	282	298	314	330	347	363	3,297
AFUDC Equity	446	483	520	557	594	632	670	708	746	784	823	861	7,824
CWIP Ending Balance	134,495	145,182	155,921	166,713	177,558	188,456	199,408	210,414	221,474	232,588	243,758	254,982	254,982
Wind													
Electric General Plant													
CWIP Beginning Balance	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765
CWIP Expenditures	13,493	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	128,493
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(13,493)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(128,493)
CWIP Ending Balance	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765
Electric Intangible Plant													
CWIP Beginning Balance	208,374	217,540	225,706	233,872	242,038	250,204	258,370	266,536	274,802	283,068	291,334	299,600	208,374
CWIP Expenditures	11,833	10,833	10,833	8,166	8,166	8,166	8,166	8,266	8,266	8,266	8,266	9,269	108,495
Closings to Plant	(2,667)	(2,667)	(2,667)	-	-	-	-	-	-	-	-	-	(8,000)
CWIP Ending Balance	217,540	225,706	233,872	242,038	250,204	258,370	266,536	274,802	283,068	291,334	299,600	308,869	308,869
Electric Other Production Plant													
CWIP Beginning Balance	56,656,013	58,626,930	59,892,357	61,102,943	65,436,671	98,179,580	105,663,836	121,436,484	124,726,769	126,925,054	128,789,217	19,503,631	56,656,013
CWIP Expenditures	2,515,432	1,697,605	3,132,984	4,147,261	32,800,497	7,980,085	15,421,965	2,909,554	1,805,478	2,044,861	2,892,499	2,550,189	79,898,412
AFUDC Debt	83,893	86,249	88,051	92,087	119,082	148,374	165,267	179,140	183,138	186,105	108,806	29,622	1,469,813
AFUDC Equity	199,066	204,656	208,932	218,508	282,564	352,071	392,156	425,075	434,560	441,601	258,180	70,289	3,487,658
Closings to Plant	(827,475)	(723,083)	(2,219,381)	(124,129)	(459,233)	(996,274)	(206,740)	(223,484)	(224,891)	(808,405)	(112,545,070)	(1,161,152)	(120,519,317)
CWIP Ending Balance	58,626,930	59,892,357	61,102,943	65,436,671	98,179,580	105,663,836	121,436,484	124,726,769	126,925,054	128,789,217	19,503,631	20,992,579	20,992,579
Electric Transmission Plant													
CWIP Beginning Balance	3,586,807	4,105,688	4,627,122	5,151,123	5,677,702	6,206,872	6,738,646	7,273,037	7,810,058	8,349,722	8,892,041	9,437,029	3,586,807
CWIP Expenditures	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	6,000,000
AFUDC Debt	5,598	6,355	7,116	7,880	8,649	9,421	10,196	10,976	11,760	12,547	13,338	14,133	117,969
AFUDC Equity	13,283	15,079	16,885	18,699	20,522	22,354	24,195	26,045	27,904	29,772	31,650	33,536	279,923
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	4,105,688	4,627,122	5,151,123	5,677,702	6,206,872	6,738,646	7,273,037	7,810,058	8,349,722	8,892,041	9,437,029	9,984,699	9,984,699
Dispatchable													
Electric General Plant													
CWIP Beginning Balance	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665
CWIP Expenditures	3,333	3,333	10,833	15,833	8,333	8,333	8,333	3,333	3,333	3,333	3,333	3,333	75,000
Closings to Plant	(3,333)	(3,333)	(10,833)	(15,833)	(8,333)	(8,333)	(8,333)	(3,333)	(3,333)	(3,333)	(3,333)	(3,333)	(75,000)
CWIP Ending Balance	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665
Electric Other Production Plant													
CWIP Beginning Balance	9,587,138	11,998,224	15,422,544	19,216,428	12,246,264	11,452,762	14,681,950	16,545,212	20,982,682	24,583,682	27,405,547	28,159,894	9,587,138
CWIP Expenditures	2,370,553	3,819,747	3,759,739	3,326,903	2,438,708	3,210,849	1,808,671	4,370,547	3,514,010	3,716,883	5,904,871	2,214,144	40,455,627
AFUDC Debt	16,073	20,337	25,573	23,660	17,702	19,385	23,090	27,676	33,527	38,290	40,863	42,929	329,103
AFUDC Equity	38,140	48,256	60,680	56,142	42,003	45,998	54,789	65,671	79,554	90,857	96,962	101,864	780,916
Closings to Plant	(13,680)	(464,020)	(52,108)	(10,376,869)	(3,291,915)	(47,044)	(23,288)	(26,424)	(26,092)	(1,024,165)	(5,288,349)	(204,085)	(20,838,038)
CWIP Ending Balance	11,998,224	15,422,544	19,216,428	12,246,264	11,452,762	14,681,950	16,545,212	20,982,682	24,583,682	27,405,547	28,159,894	30,314,745	30,314,745
Electric Steam Production Plant													
CWIP Beginning Balance	3,219,462	3,843,148	3,074,779	1,635,891	1,857,095	1,869,624	2,397,446	2,680,768	3,242,552	3,262,107	2,089,771	2,904,452	3,219,462
CWIP Expenditures	821,267	461,500	914,733	244,933	310,167	529,900	285,600	582,167	788,433	401,433	953,967	921,400	7,215,500
AFUDC Debt	5,146	5,043	3,730	2,542	2,723	3,106	3,697	4,313	4,860	3,914	3,645	4,830	47,550
AFUDC Equity	12,212	11,967	8,851	6,033	6,460	7,370	8,771	10,234	11,532	9,288	8,650	11,460	112,829
Closings to Plant	(214,939)	(1,246,879)	(2,366,202)	(32,305)	(306,820)	(12,555)	(14,746)	(34,930)	(785,269)	(1,586,972)	(151,581)	(120,658)	(6,873,856)
CWIP Ending Balance	3,843,148	3,074,779	1,635,891	1,857,095	1,869,624	2,397,446	2,680,768	3,242,552	3,262,107	2,089,771	2,904,452	3,721,484	3,721,484

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Gardner													
Dry Cask Storage													
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	20,049	40,197	60,444	100,840	201,582	302,820	454,680	607,286	-
CWIP Expenditures	-	-	-	20,000	20,000	20,000	40,000	100,000	100,000	150,000	150,000	150,000	750,000
AFUDC Debt	-	-	-	15	44	73	117	220	367	551	773	995	3,156
AFUDC Equity	-	-	-	35	104	174	279	522	871	1,308	1,834	2,362	7,488
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	20,049	40,197	60,444	100,840	201,582	302,820	454,680	607,286	760,644	760,644
Electric Nuclear Production Plant													
CWIP Beginning Balance	22,510,614	23,746,369	25,759,964	26,787,364	27,853,468	29,323,757	32,439,599	16,881,061	17,041,080	17,338,825	17,527,587	17,690,788	22,510,614
CWIP Expenditures	1,122,219	1,892,084	898,424	931,991	1,329,949	2,964,247	630,778	76,759	213,360	103,184	76,759	1,424,095	11,663,849
AFUDC Debt	33,662	36,026	38,239	39,763	41,608	44,946	36,050	24,685	25,019	25,373	25,629	26,850	397,850
AFUDC Equity	79,874	85,485	90,736	94,351	98,731	106,650	85,543	58,575	59,366	60,206	60,813	63,711	944,040
Closings to Plant	-	-	-	-	-	-	(16,310,910)	-	-	-	-	-	(16,310,910)
CWIP Ending Balance	23,746,369	25,759,964	26,787,364	27,853,468	29,323,757	32,439,599	16,881,061	17,041,080	17,338,825	17,527,587	17,690,788	19,205,443	19,205,443
Facilities & Other													
Electric General Plant													
CWIP Beginning Balance	114,765	119,765	129,765	144,765	164,765	214,765	264,765	364,765	514,765	114,765	114,765	114,765	114,765
CWIP Expenditures	5,500	10,500	15,500	20,500	60,500	62,500	112,500	162,500	162,500	32,500	32,500	22,500	700,000
Closings to Plant	(500)	(500)	(500)	(500)	(10,500)	(12,500)	(12,500)	(12,500)	(562,500)	(32,500)	(32,500)	(22,500)	(700,000)
CWIP Ending Balance	119,765	129,765	144,765	164,765	214,765	264,765	364,765	514,765	114,765	114,765	114,765	114,765	114,765
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	629,049	674,415	720,004	765,817	834,133	937,872	1,044,125	1,150,902	918,238	984,129	1,124,026	1,112,353	629,049
CWIP Expenditures	42,167	42,167	42,167	64,389	99,389	101,389	101,389	101,389	102,889	176,389	184,389	101,889	1,160,000
AFUDC Debt	949	1,015	1,081	1,164	1,290	1,442	1,597	1,521	1,384	1,534	1,658	1,526	16,162
AFUDC Equity	2,251	2,408	2,566	2,763	3,060	3,422	3,790	3,610	3,285	3,640	3,934	3,621	38,350
Closings to Plant	-	-	-	-	-	-	-	(339,184)	(41,667)	(41,667)	(201,653)	(246,177)	(870,348)
CWIP Ending Balance	674,415	720,004	765,817	834,133	937,872	1,044,125	1,150,902	918,238	984,129	1,124,026	1,112,353	973,212	973,212
Improvements													
Electric General Plant													
CWIP Beginning Balance	350,000	367,167	384,333	401,500	429,778	458,056	486,333	518,111	585,889	663,667	743,444	771,722	350,000
CWIP Expenditures	47,167	37,167	37,167	33,278	28,278	28,278	31,778	67,778	147,778	84,778	29,278	28,960	601,682
Closings to Plant	(30,000)	(20,000)	(20,000)	(5,000)	-	-	-	-	(70,000)	(5,000)	(1,000)	(100,682)	(251,682)
CWIP Ending Balance	367,167	384,333	401,500	429,778	458,056	486,333	518,111	585,889	663,667	743,444	771,722	700,000	700,000
Electric Intangible Plant													
CWIP Beginning Balance	7,977,221	-	-	-	-	-	-	-	-	-	-	-	7,977,221
CWIP Expenditures	88,550	77,050	75,900	23,574	-	-	-	-	-	-	-	-	265,074
AFUDC Debt	5,852	-	-	-	-	-	-	-	-	-	-	-	5,852
AFUDC Equity	13,885	-	-	-	-	-	-	-	-	-	-	-	13,885
Closings to Plant	(8,085,508)	(77,050)	(75,900)	(23,574)	-	-	-	-	-	-	-	-	(8,262,032)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	14,798,022	15,841,579	16,898,400	17,965,638	19,063,188	20,230,655	21,437,343	23,027,272	23,809,792	25,111,684	26,299,639	27,682,704	14,798,022
CWIP Expenditures	968,616	976,725	981,928	1,006,928	1,071,284	1,104,678	1,481,056	1,342,000	1,494,855	1,532,636	1,315,115	1,068,494	14,344,313
AFUDC Debt	22,219	23,747	25,293	26,868	28,517	30,244	32,279	34,065	35,550	37,398	39,206	39,729	375,117
AFUDC Equity	52,722	56,349	60,017	63,755	67,666	71,765	76,595	80,832	84,356	88,741	93,029	94,272	890,099
Closings to Plant	-	-	-	-	-	-	-	(674,376)	(312,870)	(470,819)	(64,285)	(1,946,144)	(3,468,495)
CWIP Ending Balance	15,841,579	16,898,400	17,965,638	19,063,188	20,230,655	21,437,343	23,027,272	23,809,792	25,111,684	26,299,639	27,682,704	26,939,056	26,939,056
Mandated Compliance													
Electric Intangible Plant													
CWIP Beginning Balance	9,844,506	10,099,100	10,307,588	10,517,101	11,670,320	12,137,155	12,606,287	13,478,491	13,883,650	14,391,049	15,450,839	15,965,950	9,844,506
CWIP Expenditures	205,643	158,400	158,400	1,098,761	408,400	408,400	808,180	338,000	438,000	986,544	438,000	838,000	6,284,728
AFUDC Debt	14,513	14,850	15,154	16,146	17,325	18,006	18,982	19,912	20,576	21,716	22,862	23,906	223,948
AFUDC Equity	34,438	35,237	35,959	38,312	41,110	42,726	45,042	47,248	48,823	51,530	54,249	56,725	531,398
CWIP Ending Balance	10,099,100	10,307,588	10,517,101	11,670,320	12,137,155	12,606,287	13,478,491	13,883,650	14,391,049	15,450,839	15,965,950	16,884,580	16,884,580

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Electric Nuclear Production Plant													
CWIP Beginning Balance	1,021,300	1,026,827	1,032,382	1,037,963	1,154,957	1,395,327	1,638,886	1,883,643	2,129,604	2,376,776	2,625,164	2,874,775	1,021,300
CWIP Expenditures	500	500	500	111,611	234,111	236,111	236,111	236,111	236,111	236,111	236,111	236,111	2,000,000
AFUDC Debt	1,490	1,499	1,507	1,596	1,856	2,208	2,563	2,920	3,279	3,640	4,002	3,665	30,225
AFUDC Equity	3,537	3,556	3,575	3,787	4,404	5,239	6,083	6,930	7,781	8,637	9,497	8,696	71,721
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(1,020,054)	(1,020,054)
CWIP Ending Balance	1,026,827	1,032,382	1,037,963	1,154,957	1,395,327	1,638,886	1,883,643	2,129,604	2,376,776	2,625,164	2,874,775	2,103,192	2,103,192
Nuclear Fuel													
Nuclear Fuel													
CWIP Beginning Balance	117,249,775	118,388,070	180,757,671	112,288,536	112,873,086	119,356,692	123,788,354	124,602,576	54,895,486	55,202,140	55,510,704	55,820,909	117,249,775
CWIP Expenditures	559,931	61,635,359	14,965,260	342,837	6,684,192	3,848,091	204,556	2,097,017	38,161	586,055	36,946	13,378,507	104,376,912
AFUDC Debt	171,476	217,691	239,820	163,852	168,996	176,939	180,756	153,236	80,119	80,567	81,017	91,202	1,805,672
AFUDC Equity	406,888	516,550	569,059	388,798	401,003	419,851	428,909	363,607	190,111	191,174	192,242	216,410	4,284,603
Closings to Plant	-	-	(84,243,274)	(310,937)	(770,585)	(13,219)	-	(72,320,950)	(1,738)	(549,231)	-	-	(158,209,934)
CWIP Ending Balance	118,388,070	180,757,671	112,288,536	112,873,086	119,356,692	123,788,354	124,602,576	54,895,486	55,202,140	55,510,704	55,820,909	69,507,028	69,507,028
Reliability													
Electric General Plant													
CWIP Beginning Balance	100,000	101,000	102,000	103,000	115,111	127,222	139,333	154,444	190,556	631,667	667,778	683,889	100,000
CWIP Expenditures	12,000	12,000	27,000	93,667	144,917	148,917	201,917	222,917	677,917	272,917	182,917	152,917	2,150,000
Closings to Plant	(11,000)	(11,000)	(26,000)	(81,556)	(132,806)	(136,806)	(186,806)	(186,806)	(236,806)	(236,806)	(166,806)	(136,806)	(1,550,000)
CWIP Ending Balance	101,000	102,000	103,000	115,111	127,222	139,333	154,444	190,556	631,667	667,778	683,889	700,000	700,000
Electric Intangible Plant													
CWIP Beginning Balance	829,440	834,624	839,834	845,070	850,331	855,618	854,842	859,149	863,477	872,739	-	-	829,440
CWIP Expenditures	1,100	1,100	1,100	1,100	1,100	390,100	3,100	1,100	5,500	56,500	12,558	6,385	480,743
AFUDC Debt	1,211	1,219	1,226	1,234	1,241	1,387	1,247	1,254	1,263	657	-	-	11,939
AFUDC Equity	2,873	2,891	2,909	2,928	2,946	3,291	2,960	2,975	2,998	1,559	-	-	28,330
Closings to Plant	-	-	-	-	-	(395,554)	(3,000)	(1,000)	(500)	(931,455)	(12,558)	(6,385)	(1,350,452)
CWIP Ending Balance	834,624	839,834	845,070	850,331	855,618	854,842	859,149	863,477	872,739	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	52,340,060	60,789,164	67,469,533	58,260,457	60,358,802	33,978,755	35,504,007	41,631,639	46,933,679	56,139,830	60,407,266	58,581,256	52,340,060
CWIP Expenditures	8,252,978	6,431,171	9,131,916	11,456,918	10,995,099	5,615,808	6,393,353	7,356,256	10,194,361	11,166,184	4,929,976	4,974,192	96,898,212
AFUDC Debt	82,316	93,326	92,081	86,359	70,581	50,584	56,132	64,543	75,008	86,077	86,996	63,022	907,026
AFUDC Equity	195,325	221,450	218,496	204,919	167,479	120,029	133,194	153,152	177,982	204,248	206,429	149,542	2,152,245
Closings to Plant	(81,516)	(65,578)	(18,651,569)	(9,649,851)	(37,613,206)	(4,261,169)	(455,048)	(2,271,911)	(1,241,200)	(7,189,072)	(7,049,411)	(36,965,891)	(125,495,422)
CWIP Ending Balance	60,789,164	67,469,533	58,260,457	60,358,802	33,978,755	35,504,007	41,631,639	46,933,679	56,139,830	60,407,266	58,581,256	26,802,121	26,802,121
Husen													
Replacements, Additions, & Repairs													
Electric General Plant													
CWIP Beginning Balance	296,944	244,261	250,783	363,148	517,404	625,382	691,168	743,884	639,986	569,257	460,080	536,256	296,944
CWIP Expenditures	607,000	974,000	5,496,000	3,911,000	4,128,000	3,913,000	4,645,667	1,691,667	1,610,667	1,347,148	3,002,667	299,667	31,626,481
Closings to Plant	(659,683)	(967,478)	(5,383,635)	(3,756,744)	(4,020,021)	(3,847,215)	(4,592,950)	(1,795,565)	(1,681,396)	(1,456,325)	(2,926,491)	(447,943)	(31,535,446)
CWIP Ending Balance	244,261	250,783	363,148	517,404	625,382	691,168	743,884	639,986	569,257	460,080	536,256	387,979	387,979
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	30,335	41,137	56,847	169,957	255,968	356,301	466,428	478,386	353,649	306,638	234,960	219,457	30,335
CWIP Expenditures	25,000	110,000	251,667	375,000	275,000	329,000	281,212	50,000	110,000	10,000	115,000	73,000	2,004,879
Closings to Plant	(14,198)	(94,289)	(138,557)	(288,989)	(174,667)	(218,873)	(269,254)	(174,737)	(157,011)	(81,679)	(130,503)	(74,348)	(1,817,105)
CWIP Ending Balance	41,137	56,847	169,957	255,968	356,301	466,428	478,386	353,649	306,638	234,960	219,457	218,108	218,108
Electric General Plant													
CWIP Beginning Balance	214,831	150,381	105,267	73,687	51,581	92,107	64,475	102,532	71,773	50,241	35,169	24,618	214,831
CWIP Expenditures	-	-	-	-	80,000	-	82,000	-	-	-	-	-	162,000
Closings to Plant	(64,449)	(45,114)	(31,580)	(22,106)	(39,474)	(27,632)	(43,942)	(30,760)	(21,532)	(15,072)	(10,551)	(7,385)	(359,598)
CWIP Ending Balance	150,381	105,267	73,687	51,581	92,107	64,475	102,532	71,773	50,241	35,169	24,618	17,233	17,233
PHEV													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	38,950	38,950	178,950	-	-	256,850
Closings to Plant	-	-	-	-	-	-	-	(38,950)	(38,950)	(178,950)	-	-	(256,850)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Expenditures	-	-	-	-	-	-	-	-	194,750	350,000	-	-	544,750
Closings to Plant	-	-	-	-	-	-	-	-	(194,750)	(350,000)	-	-	(544,750)

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Fueling Depots													
Common General Plant													
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
Moeller													
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	2,990,954	3,149,098	3,308,020	3,467,724	3,628,213	3,789,493	3,951,566	4,114,437	4,278,109	4,442,586	4,607,873	4,773,974	2,990,954
CWIP Expenditures	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	1,716,876
AFUDC Debt	4,468	4,699	4,931	5,164	5,398	5,633	5,870	6,107	6,346	6,586	6,827	7,070	69,099
AFUDC Equity	10,602	11,150	11,700	12,253	12,809	13,367	13,928	14,492	15,058	15,628	16,200	16,775	163,962
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	3,149,098	3,308,020	3,467,724	3,628,213	3,789,493	3,951,566	4,114,437	4,278,109	4,442,586	4,607,873	4,773,974	4,940,891	4,940,891
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Enterprise Security Capital													
Common General Plant													
CWIP Beginning Balance	1	1	0	0	0	0	0	0	0	0	0	0	1
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	(1)
CWIP Ending Balance	1	0	0	0	0	0	0	0	0	0	0	0	0
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Other													
Common General Plant													
CWIP Beginning Balance	576	576	576	576	576	576	576	576	576	576	576	576	576
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	576	576	576	576	576	576	576	576	576	576	576	576	576
Common Intangible Plant													
CWIP Beginning Balance	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
Electric Distribution Plant													
CWIP Beginning Balance	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
Electric General Plant													
CWIP Beginning Balance	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Electric Intangible Plant													
CWIP Beginning Balance	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
Electric Other Production Plant													
CWIP Beginning Balance	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
Electric Steam Production Plant													
CWIP Beginning Balance	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
Electric Transmission Plant													
CWIP Beginning Balance	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
Property Services Capital													
Common General Plant													
CWIP Beginning Balance	1,906,730	1,816,485	1,768,755	1,916,024	2,237,026	4,889,633	8,024,683	11,349,687	14,865,476	18,401,629	21,901,858	24,058,575	1,906,730
CWIP Expenditures	5,700	30,450	222,000	401,081	2,745,244	3,279,333	3,443,065	3,608,374	3,604,196	3,544,857	3,314,077	3,270,366	27,468,743
AFUDC Debt	2,710	2,611	2,687	3,031	5,201	9,431	14,108	19,086	24,218	29,338	33,478	19,149	165,048
AFUDC Equity	6,430	6,195	6,377	7,193	12,340	22,377	33,477	45,289	57,466	69,616	79,439	45,437	391,636
Closings to Plant	(105,085)	(86,986)	(83,795)	(90,303)	(110,178)	(176,091)	(165,646)	(156,960)	(149,727)	(143,583)	(1,270,277)	(26,777,360)	(29,315,991)
CWIP Ending Balance	1,816,485	1,768,755	1,916,024	2,237,026	4,889,633	8,024,683	11,349,687	14,865,476	18,401,629	21,901,858	24,058,575	616,166	616,166
Electric General Plant													
CWIP Beginning Balance	7,236,535	7,937,323	9,099,956	10,446,168	11,527,730	16,054,832	21,861,494	27,998,263	35,952,824	40,081,220	44,255,797	48,415,675	7,236,535
CWIP Expenditures	665,000	1,122,900	1,300,550	1,034,930	4,497,703	5,767,431	6,078,362	7,834,566	3,965,153	3,984,120	3,948,373	3,135,540	43,334,628
AFUDC Debt	11,034	12,392	14,219	15,989	20,082	27,602	36,295	46,538	55,331	61,374	67,440	60,825	429,121
AFUDC Equity	26,182	29,404	33,740	37,939	47,651	65,496	86,123	110,428	131,293	145,631	160,026	144,330	1,018,243
Closings to Plant	(1,426)	(2,064)	(2,297)	(7,295)	(38,333)	(53,868)	(64,010)	(36,971)	(23,382)	(16,547)	(15,961)	(17,637,944)	(17,900,101)
CWIP Ending Balance	7,937,323	9,099,956	10,446,168	11,527,730	16,054,832	21,861,494	27,998,263	35,952,824	40,081,220	44,255,797	48,415,675	34,118,426	34,118,426
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	2,770,950	2,161,341	1,685,846	1,353,960	1,056,089	823,749	681,524	531,589	445,839	433,555	384,973	331,479	2,770,950
CWIP Expenditures	-	-	50,000	-	-	50,000	-	40,000	110,000	60,000	40,000	40,000	390,000
Closings to Plant	(609,609)	(475,495)	(381,886)	(297,871)	(232,340)	(192,225)	(149,935)	(125,750)	(122,285)	(108,582)	(93,494)	(81,725)	(2,871,197)
CWIP Ending Balance	2,161,341	1,685,846	1,353,960	1,056,089	823,749	681,524	531,589	445,839	433,555	384,973	331,479	289,753	289,753
Electric General Plant													
CWIP Beginning Balance	1,964	1,532	1,195	932	20,227	15,777	12,306	9,599	7,487	5,840	4,555	3,553	1,964
CWIP Expenditures	-	-	-	25,000	-	-	-	-	-	-	-	-	25,000
Closings to Plant	(432)	(337)	(263)	(5,705)	(4,450)	(3,471)	(2,707)	(2,112)	(1,647)	(1,285)	(1,002)	(782)	(24,193)
CWIP Ending Balance	1,532	1,195	932	20,227	15,777	12,306	9,599	7,487	5,840	4,555	3,553	2,771	2,771
Remington													
Aging Technology													
Common General Plant													
CWIP Beginning Balance	479,383	1,884,562	3,317,573	926,210	3,106,341	5,596,018	2,806,521	5,007,559	7,708,871	4,732,618	6,962,827	9,669,158	479,383
CWIP Expenditures	1,570,869	1,570,869	2,459,869	2,284,869	2,584,869	2,459,869	2,284,869	2,781,869	2,306,869	2,306,869	2,781,869	2,274,869	27,668,428
Closings to Plant	(165,690)	(137,858)	(4,851,233)	(104,738)	(95,191)	(5,249,366)	(83,831)	(80,557)	(5,283,122)	(76,660)	(75,537)	(11,769,608)	(27,973,392)
CWIP Ending Balance	1,884,562	3,317,573	926,210	3,106,341	5,596,018	2,806,521	5,007,559	7,708,871	4,732,618	6,962,827	9,669,158	174,419	174,419
Common Intangible Plant													
CWIP Beginning Balance	12,764,566	14,240,571	2,148,276	5,705,102	9,278,801	12,869,454	16,477,146	20,101,960	23,743,981	26,930,555	30,567,695	34,222,103	12,764,566
CWIP Expenditures	1,526,960	1,526,960	5,051,614	3,539,334	3,539,334	3,539,334	3,539,334	3,539,334	3,539,334	3,502,204	3,502,204	3,502,204	39,848,153
AFUDC Debt	16,676	10,352	5,186	10,188	15,215	20,267	25,343	30,445	35,242	40,006	45,126	27,756	281,803
AFUDC Equity	39,569	24,565	12,306	24,176	36,104	48,091	60,136	72,241	83,624	94,930	107,077	65,862	668,680
Closings to Plant	(107,200)	(13,654,172)	(1,512,280)	-	-	-	-	-	(471,626)	-	-	(34,055,045)	(49,800,323)
CWIP Ending Balance	14,240,571	2,148,276	5,705,102	9,278,801	12,869,454	16,477,146	20,101,960	23,743,981	26,930,555	30,567,695	34,222,103	3,762,880	3,762,880
Electric General Plant													
CWIP Beginning Balance	31,513,647	32,511,915	33,510,324	34,547,307	10,086,595	10,625,494	10,957,797	11,498,581	12,090,314	12,425,466	12,969,113	13,513,724	31,513,647
CWIP Expenditures	866,271	862,973	955,530	2,275,931	785,650	823,896	752,231	564,455	514,455	514,455	514,455	564,452	9,994,754
AFUDC Debt	39,135	40,155	41,208	25,097	7,247	7,526	7,806	8,088	8,371	8,655	8,941	9,228	211,456
AFUDC Equity	92,862	95,281	97,781	59,551	17,196	17,858	18,523	19,191	19,862	20,537	21,215	21,897	501,755
Closings to Plant	-	-	(57,536)	(26,821,291)	(271,195)	(516,977)	(237,776)	-	(207,536)	-	-	(7,669,997)	(35,782,308)
CWIP Ending Balance	32,511,915	33,510,324	34,547,307	10,086,595	10,625,494	10,957,797	11,498,581	12,090,314	12,425,466	12,969,113	13,513,724	6,439,304	6,439,304
Electric Intangible Plant													
CWIP Beginning Balance	4,676,960	4,900,406	5,124,296	3,213,625	3,403,614	3,593,882	3,784,431	3,975,262	4,166,376	4,357,775	4,549,461	4,741,434	4,676,960
CWIP Expenditures	215,620	215,620	720,620	263,493	189,021	189,021	189,021	189,021	189,021	189,021	189,021	189,021	2,927,525
AFUDC Debt	2,320	2,452	1,394	287	370	453	536	621	705	790	875	480	11,283
AFUDC Equity	5,505	5,818	3,308	680	877	1,075	1,273	1,472	1,673	1,874	2,077	1,140	26,773
Closings to Plant	-	-	(2,635,994)	(74,471)	-	-	-	-	-	-	-	(4,932,076)	(7,642,541)
CWIP Ending Balance	4,900,406	5,124,296	3,213,625	3,403,614	3,593,882	3,784,431	3,975,262	4,166,376	4,357,775	4,549,461	4,741,434	-	-

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
AGIS													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	7,698,705	7,736,591	11,259,163	8,626,601	8,669,052	8,711,713	8,754,583	8,797,664	8,840,958	8,884,464	-	-	7,698,705
CWIP Expenditures	321,335	3,805,835	1,133,017	321,335	321,335	321,335	321,335	321,335	321,335	321,335	321,335	321,335	8,152,202
AFUDC Debt	11,350	11,405	12,053	12,703	12,765	12,828	12,890	12,953	13,016	6,598	117	117	118,796
AFUDC Equity	26,931	27,062	28,599	30,143	30,290	30,438	30,586	30,736	30,886	15,657	278	278	281,885
Closings to Plant	(321,730)	(321,730)	(3,806,230)	(321,730)	(321,730)	(321,730)	(321,730)	(321,730)	(321,730)	(9,228,055)	(321,730)	(321,730)	(16,251,588)
CWIP Ending Balance	7,736,591	11,259,163	8,626,601	8,669,052	8,711,713	8,754,583	8,797,664	8,840,958	8,884,464	-	-	-	-
Cyber Security													
Common General Plant													
CWIP Beginning Balance	-	41,667	83,333	137,330	316,327	495,324	549,320	728,317	907,314	961,311	1,140,307	1,319,304	-
CWIP Expenditures	41,667	41,667	178,997	178,997	178,997	178,997	178,997	178,997	178,997	178,997	178,997	178,997	1,873,301
Closings to Plant	-	-	(125,000)	-	-	(125,000)	-	-	(125,000)	-	-	(1,498,301)	(1,873,301)
CWIP Ending Balance	41,667	83,333	137,330	316,327	495,324	549,320	728,317	907,314	961,311	1,140,307	1,319,304	-	-
Common Intangible Plant													
CWIP Beginning Balance	1,720,196	2,579,006	3,220,025	3,708,785	4,091,161	4,399,267	4,655,583	4,875,845	5,071,071	5,248,974	5,414,953	5,572,789	1,720,196
CWIP Expenditures	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	1,267,233	15,206,796
AFUDC Debt	2,311	2,501	2,693	2,885	3,079	3,273	3,469	3,665	3,863	4,061	4,260	4,461	40,521
AFUDC Equity	5,483	5,935	6,390	6,847	7,306	7,767	8,231	8,697	9,165	9,636	10,109	10,584	96,151
Closings to Plant	(416,216)	(634,651)	(787,556)	(894,589)	(969,512)	(1,021,958)	(1,058,671)	(1,084,369)	(1,102,359)	(1,114,951)	(1,123,766)	(1,129,936)	(11,338,533)
CWIP Ending Balance	2,579,006	3,220,025	3,708,785	4,091,161	4,399,267	4,655,583	4,875,845	5,071,071	5,248,974	5,414,953	5,572,789	5,725,131	5,725,131
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergent Demand													
Common General Plant													
CWIP Beginning Balance	2,348,627	2,723,708	3,061,281	3,365,096	3,638,530	3,884,621	4,106,103	4,305,436	4,484,836	4,646,296	4,791,611	4,922,393	2,348,627
CWIP Expenditures	677,715	677,715	677,715	677,715	677,715	677,715	677,715	677,715	677,715	677,715	677,715	677,715	8,132,583
Closings to Plant	(302,634)	(340,142)	(373,900)	(404,281)	(431,625)	(456,234)	(478,382)	(498,315)	(516,255)	(532,401)	(546,933)	(560,011)	(5,441,112)
CWIP Ending Balance	2,723,708	3,061,281	3,365,096	3,638,530	3,884,621	4,106,103	4,305,436	4,484,836	4,646,296	4,791,611	4,922,393	5,040,098	5,040,098
Common Intangible Plant													
CWIP Beginning Balance	242,262	75,792	(40,737)	(122,308)	(179,407)	(219,376)	(247,355)	(266,940)	(280,649)	(290,246)	(296,964)	(301,666)	242,262
CWIP Expenditures	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(133,988)	(1,607,854)
Closings to Plant	(32,482)	17,459	52,418	76,889	94,018	106,009	114,403	120,278	124,391	127,270	129,286	130,696	1,060,635
CWIP Ending Balance	75,792	(40,737)	(122,308)	(179,407)	(219,376)	(247,355)	(266,940)	(280,649)	(290,246)	(296,964)	(301,666)	(304,958)	(304,958)
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	21,725,811	21,928,439	22,119,260	22,330,226	22,523,025	22,735,978	22,943,576	23,074,935	23,212,995	-	-	-	21,725,811
CWIP Expenditures	140,492	127,720	146,878	127,720	146,878	140,492	63,420	69,460	63,420	-	-	500,000	1,526,480
AFUDC Debt	18,422	18,709	19,001	19,295	19,590	19,896	20,143	20,339	10,268	-	-	-	165,663
AFUDC Equity	43,714	44,393	45,087	45,784	46,485	47,211	47,796	48,261	24,364	-	-	-	393,094
Closings to Plant	-	-	-	-	-	-	-	-	(23,311,048)	-	-	(500,000)	(23,811,048)
CWIP Ending Balance	21,928,439	22,119,260	22,330,226	22,523,025	22,735,978	22,943,576	23,074,935	23,212,995	-	-	-	-	-
Common Intangible Plant													
CWIP Beginning Balance	5,702,906	6,754,408	7,811,084	8,942,884	10,079,909	11,222,186	12,369,740	13,522,597	14,680,782	15,667,835	16,824,843	17,987,200	5,702,906
CWIP Expenditures	1,090,075	1,090,075	1,159,999	1,090,870	1,090,870	1,090,870	1,090,870	1,090,870	1,090,870	1,090,870	1,090,870	3,189,870	15,256,982
AFUDC Debt	9,059	10,593	12,135	13,684	15,241	16,806	18,378	19,958	21,422	22,876	24,462	18,582	203,196
AFUDC Equity	21,496	25,137	28,795	32,471	36,165	39,878	43,608	47,358	50,831	54,281	58,045	44,093	482,156
Closings to Plant	(69,129)	(69,129)	(69,129)	-	-	-	-	-	(176,070)	(11,020)	(11,020)	(13,480,050)	(13,885,546)
CWIP Ending Balance	6,754,408	7,811,084	8,942,884	10,079,909	11,222,186	12,369,740	13,522,597	14,680,782	15,667,835	16,824,843	17,987,200	7,759,694	7,759,694

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July
Electric General Plant							
CWIP Beginning Balance	250,000	279,167	308,333	337,500	366,667	395,833	425,000
CWIP Expenditures	29,167	29,167	29,167	29,167	29,167	29,167	29,167
Closings to Plant	-	-	-	-	-	-	-
CWIP Ending Balance	279,167	308,333	337,500	366,667	395,833	425,000	454,167
Electric Intangible Plant							
CWIP Beginning Balance	12,287,912	13,817,009	14,371,878	11,979,487	12,842,967	9,041,386	9,489,424
CWIP Expenditures	1,466,225	1,466,226	976,554	976,554	802,554	402,554	402,554
AFUDC Debt	18,640	20,157	19,245	18,064	16,079	13,485	14,139
AFUDC Equity	44,231	47,830	45,667	42,862	38,153	31,998	33,549
Closings to Plant	-	(979,343)	(3,433,858)	(174,000)	(4,658,367)	-	-
CWIP Ending Balance	13,817,009	14,371,878	11,979,487	12,842,967	9,041,386	9,489,424	9,939,666
Customer							
Common General Plant							
CWIP Beginning Balance	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-
Common Intangible Plant							
CWIP Beginning Balance	-	-	-	-	-	-	-
CWIP Expenditures	101,514	101,514	101,514	101,514	101,514	101,514	101,514
AFUDC Debt	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-
Closings to Plant	(101,514)	(101,514)	(101,514)	(101,514)	(101,514)	(101,514)	(101,514)
CWIP Ending Balance	-	-	-	-	-	-	-

	2023 August	2023 September	2023 October	2023 November	2023 December	2023 Year-to-date
Electric General Plant						
CWIP Beginning Balance	454,167	483,333	512,500	541,667	570,833	250,000
CWIP Expenditures	29,167	29,167	29,167	29,167	29,167	350,000
Closings to Plant	-	-	-	-	-	-
CWIP Ending Balance	483,333	512,500	541,667	570,833	600,000	600,000
Electric Intangible Plant						
CWIP Beginning Balance	9,939,666	10,392,123	10,846,808	11,303,729	11,762,900	12,287,912
CWIP Expenditures	402,554	402,554	402,554	402,554	402,554	8,505,992
AFUDC Debt	14,796	15,456	16,119	16,786	10,945	193,911
AFUDC Equity	35,108	36,674	38,248	39,830	25,972	460,123
Closings to Plant	-	-	-	-	(9,087,969)	(18,333,536)
CWIP Ending Balance	10,392,123	10,846,808	11,303,729	11,762,900	3,114,402	3,114,402
Customer						
Common General Plant						
CWIP Beginning Balance	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-
Common Intangible Plant						
CWIP Beginning Balance	-	-	-	-	-	-
CWIP Expenditures	101,514	101,514	101,514	101,514	101,514	1,218,164
AFUDC Debt	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-
Closings to Plant	(101,514)	(101,514)	(101,514)	(101,514)	(101,514)	(1,218,164)
CWIP Ending Balance	-	-	-	-	-	-

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Benson													
Asset Renewal													
Electric General Plant													
CWIP Beginning Balance	5,000,000	5,718,975	5,928,358	6,050,000	6,763,975	6,978,358	7,100,000	7,884,770	8,214,048	8,150,000	8,893,870	9,140,148	5,000,000
CWIP Expenditures	718,771	208,771	483,771	713,771	213,771	509,241	784,566	328,666	663,666	743,666	245,666	519,670	6,133,996
AFUDC Debt	61	184	154	61	184	154	61	184	154	61	184	154	1,594
AFUDC Equity	143	428	358	143	428	358	143	428	358	143	428	358	3,716
Closings to Plant	-	-	(362,640)	-	-	(388,110)	-	-	(728,225)	-	-	(3,660,329)	(5,139,306)
CWIP Ending Balance	5,718,975	5,928,358	6,050,000	6,763,975	6,978,358	7,100,000	7,884,770	8,214,048	8,150,000	8,893,870	9,140,148	6,000,000	6,000,000
Electric Transmission Plant													
CWIP Beginning Balance	39,226,888	47,450,666	55,282,015	49,367,487	58,445,861	68,797,592	59,227,060	72,743,715	83,081,640	70,414,968	82,294,701	96,241,049	39,226,888
CWIP Expenditures	12,873,725	8,611,929	15,982,965	9,830,049	11,055,049	15,459,388	14,708,208	11,470,108	17,980,224	12,519,671	14,585,695	18,689,111	163,766,122
AFUDC Debt	66,511	77,130	81,342	80,933	95,450	98,771	99,169	116,992	118,309	114,477	133,796	125,219	1,208,100
AFUDC Equity	155,044	179,798	189,617	188,664	222,505	230,247	231,174	272,721	275,791	266,858	311,894	291,898	2,816,212
Closings to Plant	(4,871,502)	(1,037,508)	(22,168,453)	(1,021,272)	(1,021,272)	(25,358,939)	(1,521,896)	(1,521,896)	(31,040,996)	(1,021,272)	(1,085,037)	(50,905,617)	(142,575,661)
CWIP Ending Balance	47,450,666	55,282,015	49,367,487	58,445,861	68,797,592	59,227,060	72,743,715	83,081,640	70,414,968	82,294,701	96,241,049	64,441,661	64,441,661
Comm Infrastructure													
Electric General Plant													
CWIP Beginning Balance	-	1,398,863	3,013,481	-	1,607,637	3,223,296	-	2,590,082	5,193,089	-	2,590,082	5,193,089	-
CWIP Expenditures	1,395,382	1,603,636	1,613,636	1,603,636	1,603,636	1,613,636	2,583,636	2,583,636	2,658,636	2,583,636	2,583,636	3,015,000	25,441,742
AFUDC Debt	1,045	3,297	2,861	1,201	3,609	3,019	1,935	5,815	4,885	1,935	5,815	5,019	40,437
AFUDC Equity	2,436	7,685	6,670	2,800	8,414	7,037	4,511	13,556	11,388	4,511	13,556	11,699	94,262
Closings to Plant	-	-	(4,636,649)	-	-	(4,846,987)	-	-	(7,867,998)	-	-	(8,224,807)	(25,576,441)
CWIP Ending Balance	1,398,863	3,013,481	-	1,607,637	3,223,296	-	2,590,082	5,193,089	-	2,590,082	5,193,089	-	-
Electric Transmission Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Interconnection													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	6,262,697	6,298,961	6,335,405	8,522,917	8,570,458	8,618,238	10,242,517	10,393,876	10,545,991	14,757,566	15,833,702	16,915,207	6,262,697
CWIP Expenditures	244,654	244,654	5,244,654	5,000	5,000	5,075,000	100,000	100,000	9,966,365	1,000,000	1,000,000	6,000,000	28,985,327
AFUDC Debt	9,385	9,440	11,577	12,771	12,842	14,596	15,418	15,645	20,045	22,856	24,468	24,694	193,737
AFUDC Equity	21,878	22,005	26,988	29,771	29,937	34,024	35,941	36,470	46,728	53,279	57,037	57,564	451,622
Closings to Plant	(239,654)	(239,654)	(3,095,707)	-	-	(3,499,341)	-	-	(5,821,563)	-	-	(8,011,557)	(20,907,476)
CWIP Ending Balance	6,298,961	6,335,405	8,522,917	8,570,458	8,618,238	10,242,517	10,393,876	10,545,991	14,757,566	15,833,702	16,915,207	14,985,907	14,985,907
Regional Expansion													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	33,638,057	34,194,378	36,758,465	42,242,582	44,814,578	47,303,942	40,115,205	42,320,370	44,536,538	51,675,991	53,938,845	56,714,237	33,638,057
CWIP Expenditures	387,500	2,387,500	5,287,500	2,355,329	2,260,100	7,140,509	2,093,500	2,000,000	6,900,000	2,000,000	2,500,000	7,900,000	43,211,938
AFUDC Debt	50,680	53,011	59,025	65,044	68,825	65,431	61,591	64,894	71,884	78,909	82,673	90,875	812,840
AFUDC Equity	118,141	123,575	137,593	151,624	160,439	152,526	143,574	151,275	167,569	183,945	192,719	211,840	1,894,818
Closings to Plant	-	-	-	-	-	(14,547,202)	(93,500)	-	-	-	-	-	(14,640,702)
CWIP Ending Balance	34,194,378	36,758,465	42,242,582	44,814,578	47,303,942	40,115,205	42,320,370	44,536,538	51,675,991	53,938,845	56,714,237	64,916,951	64,916,951

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Reliability Requirement													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	30,381,591	36,667,899	36,850,871	43,150,222	48,523,378	49,747,955	55,680,589	62,000,473	62,334,416	67,912,318	73,287,228	73,652,931	30,381,591
CWIP Expenditures	7,350,000	-	6,350,255	5,145,000	980,000	5,920,255	6,027,000	24,500	5,503,755	5,176,500	225,000	9,290,257	51,992,522
AFUDC Debt	50,554	54,928	59,865	68,493	73,422	78,863	87,924	92,895	97,406	105,507	109,868	105,446	985,171
AFUDC Equity	117,846	128,044	139,552	159,664	171,155	183,838	204,960	216,548	227,063	245,949	256,115	245,806	2,296,541
Closings to Plant	(1,232,093)	-	(250,322)	-	-	(250,322)	-	-	(250,322)	(153,046)	(225,281)	(16,026,897)	(18,388,282)
CWIP Ending Balance	36,667,899	36,850,871	43,150,222	48,523,378	49,747,955	55,680,589	62,000,473	62,334,416	67,912,318	73,287,228	73,652,931	67,267,543	67,267,543
Security\Resiliency													
Electric General Plant													
CWIP Beginning Balance	-	293,331	294,796	501,250	1,298,328	1,806,054	2,020,049	2,824,707	3,340,050	3,561,699	4,080,717	4,101,080	-
CWIP Expenditures	292,601	1	500,000	792,600	500,000	500,000	792,600	500,000	500,000	792,597	1	500,000	5,670,400
AFUDC Debt	219	439	595	1,345	2,319	2,859	3,620	4,606	5,157	5,820	6,113	3,259	36,351
AFUDC Equity	511	1,024	1,388	3,134	5,407	6,665	8,438	10,737	12,022	13,566	14,250	7,597	84,738
Closings to Plant	-	-	(295,529)	-	-	(295,529)	-	-	(295,529)	(292,965)	-	(4,611,936)	(5,791,489)
CWIP Ending Balance	293,331	294,796	501,250	1,298,328	1,806,054	2,020,049	2,824,707	3,340,050	3,561,699	4,080,717	4,101,080	-	-
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	465,000	-	-	465,000	-	-	465,000	-	-	465,000	1,860,000
AFUDC Debt	-	-	174	-	-	174	-	-	174	-	-	174	697
AFUDC Equity	-	-	406	-	-	406	-	-	406	-	-	406	1,624
Closings to Plant	-	-	(465,580)	-	-	(465,580)	-	-	(465,580)	-	-	(465,580)	(1,862,320)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Transmission Plant													
CWIP Beginning Balance	57,038	57,334	57,621	559,156	561,957	564,762	1,570,076	1,577,921	1,585,796	3,598,699	9,130,389	9,175,950	57,038
CWIP Expenditures	11	1	500,000	11	1	1,000,000	11	1	2,000,000	5,500,010	-	1	9,000,047
AFUDC Debt	85	86	461	838	842	1,595	2,352	2,364	3,874	9,510	13,677	6,918	42,601
AFUDC Equity	199	200	1,074	1,953	1,962	3,718	5,483	5,510	9,030	22,170	31,883	16,126	99,309
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(9,138,405)	(9,138,405)
CWIP Ending Balance	57,334	57,621	559,156	561,957	564,762	1,570,076	1,577,921	1,585,796	3,598,699	9,130,389	9,175,950	60,591	60,591
Bloch													
AGIS													
Electric Distribution Plant													
CWIP Beginning Balance	1,548,571	1,638,311	1,728,498	1,819,136	1,910,225	2,001,769	2,093,770	2,186,230	2,279,152	2,372,537	2,466,388	2,560,707	1,548,571
CWIP Expenditures	9,595,928	9,326,582	9,326,583	9,595,928	9,326,583	9,326,583	9,595,928	9,326,583	4,794,973	4,794,972	4,039,937	12,259,534	101,310,112
AFUDC Debt	3,546	3,681	3,816	3,952	4,088	4,225	4,363	4,501	4,641	4,780	4,921	8,243	54,756
AFUDC Equity	8,267	8,580	8,895	9,211	9,529	9,849	10,170	10,493	10,818	11,144	11,472	19,215	127,643
Closings to Plant	(9,518,001)	(9,248,655)	(9,248,656)	(9,518,001)	(9,248,656)	(9,248,656)	(9,518,001)	(9,248,656)	(4,717,046)	(4,717,045)	(3,962,011)	(12,192,201)	(100,385,585)
CWIP Ending Balance	1,638,311	1,728,498	1,819,136	1,910,225	2,001,769	2,093,770	2,186,230	2,279,152	2,372,537	2,466,388	2,560,707	2,655,497	2,655,497
Electric General Plant													
CWIP Beginning Balance	21,500,888	22,590,517	23,678,744	24,770,009	24,875,478	24,980,948	25,086,417	25,515,178	25,580,459	25,645,740	25,711,022	-	21,500,888
CWIP Expenditures	1,313,682	1,386,038	1,425,565	501,813	474,188	499,975	823,267	515,037	523,667	573,507	392,790	4,523,955	12,953,483
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(224,053)	(297,811)	(334,301)	(396,343)	(368,718)	(394,506)	(394,506)	(449,756)	(458,386)	(508,226)	(26,103,811)	(4,523,955)	(34,454,371)
CWIP Ending Balance	22,590,517	23,678,744	24,770,009	24,875,478	24,980,948	25,086,417	25,515,178	25,580,459	25,645,740	25,711,022	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	6,908,744	7,086,852	7,265,849	7,445,739	7,676,652	7,908,716	8,141,939	8,376,326	8,561,757	8,748,114	8,935,400	9,123,621	6,908,744
CWIP Expenditures	143,276	143,276	143,276	193,276	193,276	193,276	193,276	143,276	143,276	143,276	143,276	143,276	1,919,312
AFUDC Debt	10,457	10,723	10,992	11,298	11,644	11,992	12,341	12,655	12,933	13,212	13,493	13,097	144,837
AFUDC Equity	24,376	24,997	25,623	26,338	27,144	27,955	28,769	29,500	30,148	30,799	31,453	30,531	337,631
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(945,064)	(945,064)
CWIP Ending Balance	7,086,852	7,265,849	7,445,739	7,676,652	7,908,716	8,141,939	8,376,326	8,561,757	8,748,114	8,935,400	9,123,621	8,365,461	8,365,461
Asset Health & Reliability													
Electric Distribution Plant													
CWIP Beginning Balance	57,606,243	59,213,411	60,788,685	62,369,657	64,025,698	65,990,421	68,146,027	71,402,981	74,246,144	76,541,611	54,021,920	54,146,277	57,606,243
CWIP Expenditures	15,690,299	15,690,299	15,729,014	15,848,004	16,188,274	16,421,094	18,197,189	18,197,189	17,886,349	16,095,834	15,041,084	16,848,380	197,833,009
AFUDC Debt	52,972	55,196	57,433	59,769	62,412	65,457	68,835	72,238	75,308	60,563	44,381	43,586	718,150
AFUDC Equity	123,484	128,668	133,883	139,327	145,488	152,586	160,463	168,395	175,552	141,179	103,456	101,605	1,674,086
Closings to Plant	(14,259,587)	(14,298,890)	(14,339,358)	(14,391,059)	(14,431,451)	(14,483,531)	(15,169,533)	(15,594,659)	(15,841,742)	(38,817,266)	(15,064,564)	(18,099,430)	(204,791,070)
CWIP Ending Balance	59,213,411	60,788,685	62,369,657	64,025,698	65,990,421	68,146,027	71,402,981	74,246,144	76,541,611	54,021,920	54,146,277	53,040,419	53,040,419

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Electric General Plant													
CWIP Beginning Balance	39,802	39,462	39,222	39,054	38,936	38,852	38,794	40,188	41,168	41,857	40,906	40,238	39,802
CWIP Expenditures	16,368	16,368	16,368	16,368	16,368	16,368	18,414	18,414	18,414	16,368	16,368	18,414	204,600
AFUDC Debt	61	61	60	60	60	60	61	63	64	64	63	63	740
AFUDC Equity	142	141	141	140	140	140	142	147	150	149	146	147	1,724
Closings to Plant	(16,912)	(16,810)	(16,737)	(16,687)	(16,651)	(16,626)	(17,223)	(17,643)	(17,939)	(17,531)	(17,245)	(17,658)	(205,663)
CWIP Ending Balance	39,462	39,222	39,054	38,936	38,852	38,794	40,188	41,168	41,857	40,906	40,238	41,203	41,203
Capacity													
Electric Distribution Plant													
CWIP Beginning Balance	8,744,002	11,017,273	13,229,675	15,517,791	18,236,590	21,359,650	17,802,936	20,719,721	23,587,814	26,074,564	7,053,042	7,112,950	8,744,002
CWIP Expenditures	3,956,024	3,967,304	4,089,909	4,549,029	4,967,839	5,545,618	4,875,473	4,875,473	4,525,068	3,810,834	2,113,181	2,306,828	49,582,580
AFUDC Debt	11,304	14,494	17,727	21,364	25,644	25,646	24,678	28,847	32,729	20,955	6,194	5,530	235,112
AFUDC Equity	26,350	33,788	41,324	49,801	59,779	59,785	57,526	67,246	76,295	48,848	14,438	12,891	548,071
Closings to Plant	(1,720,407)	(1,803,184)	(1,860,844)	(1,901,394)	(1,930,202)	(9,187,763)	(2,040,891)	(2,103,474)	(2,147,343)	(22,902,159)	(2,073,905)	(3,282,975)	(52,954,541)
CWIP Ending Balance	11,017,273	13,229,675	15,517,791	18,236,590	21,359,650	17,802,936	20,719,721	23,587,814	26,074,564	7,053,042	7,112,950	6,155,225	6,155,225
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Vehicles													
Electric Distribution Plant													
CWIP Beginning Balance	12,764,106	12,276,733	11,933,878	11,692,690	11,523,022	11,403,667	11,319,704	11,674,764	11,923,962	12,098,862	11,807,491	11,602,900	12,764,106
CWIP Expenditures	4,725,840	4,725,840	4,725,840	4,725,840	4,725,840	4,725,840	5,316,570	5,316,570	5,316,570	4,725,840	4,725,840	5,316,570	59,073,000
AFUDC Debt	14,483	13,757	13,246	12,888	12,635	12,458	12,597	12,878	13,076	12,952	12,680	12,753	156,402
AFUDC Equity	33,761	32,068	30,879	30,043	29,455	29,041	29,364	30,020	30,480	30,192	29,559	29,728	364,589
Closings to Plant	(5,261,457)	(5,114,519)	(5,011,153)	(4,938,438)	(4,887,286)	(4,851,302)	(5,003,470)	(5,110,269)	(5,185,226)	(5,060,353)	(4,972,671)	(5,088,585)	(60,484,731)
CWIP Ending Balance	12,276,733	11,933,878	11,692,690	11,523,022	11,403,667	11,319,704	11,674,764	11,923,962	12,098,862	11,807,491	11,602,900	11,873,365	11,873,365
Mandates													
Electric Distribution Plant													
CWIP Beginning Balance	6,835,183	7,017,757	7,171,499	7,298,713	7,402,798	7,487,331	7,555,646	7,851,365	8,067,843	8,229,959	8,112,870	8,036,151	6,835,183
CWIP Expenditures	2,776,777	2,776,777	2,776,777	2,776,777	2,776,777	2,776,777	3,123,875	3,123,875	3,123,875	2,776,777	2,776,777	3,123,875	34,709,716
AFUDC Debt	3,938	3,902	3,874	3,851	3,832	3,817	3,856	3,929	3,987	3,983	3,938	3,954	46,860
AFUDC Equity	9,180	9,097	9,030	8,976	8,933	8,898	8,990	9,159	9,295	9,284	9,181	9,217	109,237
Closings to Plant	(2,607,321)	(2,636,034)	(2,662,466)	(2,685,518)	(2,705,008)	(2,721,177)	(2,841,002)	(2,920,484)	(2,975,041)	(2,907,133)	(2,866,615)	(2,948,386)	(33,476,186)
CWIP Ending Balance	7,017,757	7,171,499	7,298,713	7,402,798	7,487,331	7,555,646	7,851,365	8,067,843	8,229,959	8,112,870	8,036,151	8,224,811	8,224,811
New Business													
Electric Distribution Plant													
CWIP Beginning Balance	7,443,285	7,241,631	7,126,966	7,060,916	7,022,217	6,999,045	6,984,798	7,324,777	7,519,460	7,632,630	7,350,693	7,190,813	7,443,285
CWIP Expenditures	4,917,597	4,917,597	4,917,597	4,917,597	4,917,597	4,917,597	5,532,296	5,532,296	5,532,296	4,917,597	4,917,597	5,532,296	61,469,960
AFUDC Debt	0	0	0	0	0	0	-	-	-	-	-	-	0
AFUDC Equity	0	0	0	0	0	0	0	0	0	-	-	-	0
Closings to Plant	(5,119,251)	(5,032,262)	(4,983,647)	(4,956,296)	(4,940,769)	(4,931,844)	(5,192,317)	(5,337,613)	(5,419,127)	(5,199,534)	(5,077,477)	(5,275,027)	(61,465,163)
CWIP Ending Balance	7,241,631	7,126,966	7,060,916	7,022,217	6,999,045	6,984,798	7,324,777	7,519,460	7,632,630	7,350,693	7,190,813	7,448,082	7,448,082
Solar													
Electric Distribution Plant													
CWIP Beginning Balance	(115)	(95)	(79)	(66)	(55)	(47)	(39)	(33)	(29)	(24)	(21)	(18)	(115)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	0	0	0	0	0	0	0	0	0	0	0	0	2
AFUDC Equity	1	1	1	1	0	0	0	0	0	0	0	0	5
Closings to Plant	19	15	12	10	8	7	6	5	4	3	3	2	93
CWIP Ending Balance	(95)	(79)	(66)	(55)	(47)	(39)	(33)	(29)	(24)	(21)	(18)	(16)	(16)
Electric General Plant													
CWIP Beginning Balance	(918)	(734)	(587)	(470)	(376)	(301)	(241)	(193)	(154)	(123)	(99)	(79)	(918)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	184	147	117	94	75	60	48	39	31	25	20	16	855
CWIP Ending Balance	(734)	(587)	(470)	(376)	(301)	(241)	(193)	(154)	(123)	(99)	(79)	(63)	(63)

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	70,372	69,716	69,257	68,935	68,710	68,552	68,442	70,922	72,658	73,873	72,166	70,972	70,372
CWIP Expenditures	29,222	29,222	29,222	29,222	29,222	29,222	32,875	32,875	32,875	29,222	29,222	32,875	365,276
Closings to Plant	(29,878)	(29,681)	(29,544)	(29,447)	(29,380)	(29,332)	(30,395)	(31,139)	(31,660)	(30,929)	(30,417)	(31,154)	(362,955)
CWIP Ending Balance	69,716	69,257	68,935	68,710	68,552	68,442	70,922	72,658	73,873	72,166	70,972	72,693	72,693
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Distribution Plant													
CWIP Beginning Balance	2,352,156	2,361,982	2,372,318	2,383,029	2,394,020	2,405,224	2,416,595	2,430,900	2,444,477	2,457,562	2,467,521	2,478,108	2,352,156
CWIP Expenditures	32,000	32,000	32,000	32,000	32,000	32,000	36,000	36,000	36,000	32,000	32,000	36,000	400,000
AFUDC Debt	3,404	3,421	3,438	3,455	3,473	3,490	3,507	3,525	3,542	3,560	3,578	3,596	41,989
AFUDC Equity	7,935	7,975	8,015	8,055	8,095	8,135	8,176	8,217	8,258	8,299	8,340	8,382	97,882
Closings to Plant	(33,514)	(33,060)	(32,742)	(32,519)	(32,363)	(32,254)	(33,378)	(34,165)	(34,715)	(33,901)	(33,330)	(34,131)	(400,072)
CWIP Ending Balance	2,361,982	2,372,318	2,383,029	2,394,020	2,405,224	2,416,595	2,430,900	2,444,477	2,457,562	2,467,521	2,478,108	2,491,955	2,491,955
Electric General Plant													
CWIP Beginning Balance	7,198,128	7,029,672	6,912,843	6,836,299	6,848,778	6,896,242	7,011,414	7,227,528	7,423,290	7,556,577	7,614,918	7,668,955	7,198,128
CWIP Expenditures	1,130,876	1,130,876	1,130,876	1,195,154	1,215,821	1,277,312	1,409,163	1,409,163	1,356,040	1,250,178	1,222,540	1,556,623	15,284,622
AFUDC Debt	9,880	9,717	9,612	9,598	9,670	9,814	10,077	10,378	10,619	10,760	10,862	10,764	121,750
AFUDC Equity	23,031	22,651	22,407	22,375	22,542	22,876	23,490	24,192	24,753	25,082	25,321	25,091	283,812
Closings to Plant	(1,332,242)	(1,280,073)	(1,239,440)	(1,214,648)	(1,200,569)	(1,194,830)	(1,226,616)	(1,247,971)	(1,258,124)	(1,227,680)	(1,204,686)	(1,957,287)	(15,584,166)
CWIP Ending Balance	7,029,672	6,912,843	6,836,299	6,848,778	6,896,242	7,011,414	7,227,528	7,423,290	7,556,577	7,614,918	7,668,955	7,304,146	7,304,146
Capra													
Coal													
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	16,667	16,667	18,917	21,917	24,917	27,917	30,917	33,917	39,167	46,667	40,667	31,667	350,000
Closings to Plant	(16,667)	(16,667)	(18,917)	(21,917)	(24,917)	(27,917)	(30,917)	(33,917)	(39,167)	(46,667)	(40,667)	(31,667)	(350,000)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Steam Production Plant													
CWIP Beginning Balance	3,175,896	3,567,066	4,209,858	5,689,160	6,029,035	5,656,118	2,476,484	3,092,187	3,400,656	3,640,562	3,288,100	2,684,026	3,175,896
CWIP Expenditures	437,458	644,114	1,492,207	912,374	1,212,721	478,438	872,019	557,572	576,917	1,205,909	349,747	1,304,894	10,044,370
AFUDC Debt	5,040	5,812	7,399	8,785	8,835	6,090	4,168	4,869	5,276	5,250	4,502	3,052	69,078
AFUDC Equity	11,748	13,549	17,247	20,480	20,596	14,197	9,716	11,350	12,298	12,237	10,495	7,115	161,028
Closings to Plant	(63,076)	(20,683)	(37,551)	(601,763)	(1,615,069)	(3,678,360)	(270,199)	(265,322)	(354,584)	(1,575,859)	(968,818)	(3,110,868)	(12,562,152)
CWIP Ending Balance	3,567,066	4,209,858	5,689,160	6,029,035	5,656,118	2,476,484	3,092,187	3,400,656	3,640,562	3,288,100	2,684,026	888,220	888,220
Hydro													
Electric General Plant													
CWIP Expenditures	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
Closings to Plant	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(1,250)	(15,000)
Electric Hydro Production Plant													
CWIP Beginning Balance	441,072	481,283	521,695	562,309	603,125	644,144	685,368	726,798	768,435	810,280	852,332	894,594	441,072
CWIP Expenditures	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,916	37,924	455,000
AFUDC Debt	689	749	810	871	932	993	1,055	1,117	1,180	1,242	1,305	1,369	12,312
AFUDC Equity	1,606	1,747	1,888	2,030	2,172	2,316	2,460	2,604	2,750	2,896	3,043	3,190	28,701
Closings to Plant	(0)	(0)	(0)	(0)	(2)	(0)	(0)	(1)	(1)	(2)	(1)	(1)	(8)
CWIP Ending Balance	481,283	521,695	562,309	603,125	644,144	685,368	726,798	768,435	810,280	852,332	894,594	937,076	937,076
Intermediate													
Electric General Plant													
CWIP Beginning Balance	128,015	128,005	128,456	141,410	154,364	167,318	180,273	180,727	181,182	181,636	182,091	182,546	128,015
CWIP Expenditures	12,813	13,267	57,100	73,767	73,767	68,767	72,934	27,934	41,600	206,600	21,600	21,600	691,750
Closings to Plant	(12,823)	(12,816)	(44,147)	(60,813)	(60,813)	(55,813)	(72,479)	(27,479)	(41,146)	(206,146)	(21,146)	(21,146)	(636,765)
CWIP Ending Balance	128,005	128,456	141,410	154,364	167,318	180,273	180,727	181,182	181,636	182,091	182,546	183,000	183,000
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Other Production Plant													
CWIP Beginning Balance	6,572,217	8,092,898	10,372,932	10,066,567	12,351,062	14,356,420	17,099,928	11,104,810	13,654,065	13,631,967	12,379,481	4,521,230	6,572,217
CWIP Expenditures	1,538,297	2,257,315	2,610,352	2,726,846	2,765,049	2,848,382	2,956,100	3,670,501	3,953,656	1,819,287	2,442,841	1,259,259	30,847,884
AFUDC Debt	10,957	13,798	15,491	16,755	20,013	23,511	21,465	18,525	20,649	19,622	12,979	6,402	200,167
AFUDC Equity	25,543	32,164	36,111	39,058	46,652	54,807	50,038	43,183	48,135	45,741	30,255	14,924	466,612
Closings to Plant	(54,116)	(23,242)	(2,968,319)	(498,164)	(826,356)	(183,192)	(9,022,722)	(1,182,954)	(4,044,538)	(3,137,136)	(10,344,326)	(1,863,312)	(34,148,378)
CWIP Ending Balance	8,092,898	10,372,932	10,066,567	12,351,062	14,356,420	17,099,928	11,104,810	13,654,065	13,631,967	12,379,481	4,521,230	3,938,502	3,938,502

Northern States Power Company
CWIP by Witness, Functional Class, and Category

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 3
Page 43 of 49

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Solar													
Electric Other Production Plant													
CWIP Beginning Balance	180,272,352	200,102,579	220,031,759	253,833,876	290,261,065	326,870,026	359,153,258	388,543,707	416,877,819	445,096,687	181,080,497	194,780,417	180,272,352
CWIP Expenditures	18,883,554	18,883,554	32,622,765	35,073,051	35,073,051	30,575,864	27,529,587	26,329,587	26,073,593	26,073,593	18,893,329	20,763,646	316,775,174
AFUDC Debt	284,192	313,897	354,042	406,513	461,081	512,553	558,631	601,759	644,012	473,341	280,819	301,342	5,192,182
AFUDC Equity	662,482	731,729	825,310	947,625	1,074,829	1,194,816	1,302,230	1,402,766	1,501,262	1,103,410	654,620	702,460	12,103,538
Closings to Plant	-	-	-	-	-	-	-	-	-	(291,666,534)	(6,128,849)	(7,999,166)	(305,794,548)
CWIP Ending Balance	200,102,579	220,031,759	253,833,876	290,261,065	326,870,026	359,153,258	388,543,707	416,877,819	445,096,687	181,080,497	194,780,417	208,548,698	208,548,698
Electric Transmission Plant													
CWIP Beginning Balance	254,982	266,279	277,633	289,043	300,510	312,035	323,617	335,257	346,954	358,711	370,526	382,400	254,982
CWIP Expenditures	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	120,000
AFUDC Debt	389	406	423	440	458	475	492	510	527	545	563	580	5,809
AFUDC Equity	908	947	987	1,027	1,067	1,107	1,148	1,188	1,229	1,270	1,311	1,353	13,542
CWIP Ending Balance	266,279	277,633	289,043	300,510	312,035	323,617	335,257	346,954	358,711	370,526	382,400	394,333	394,333
Wind													
Electric General Plant													
CWIP Beginning Balance	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765
CWIP Expenditures	5,000	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	10,455	120,000
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(5,000)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(10,455)	(120,000)
CWIP Ending Balance	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765	78,765
Electric Intangible Plant													
CWIP Beginning Balance	308,869	315,035	321,201	327,367	333,533	339,699	345,865	352,031	358,197	364,363	370,529	376,695	308,869
CWIP Expenditures	6,166	6,166	6,166	6,166	6,166	6,166	6,166	6,166	6,166	6,166	6,166	7,166	74,992
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(203,966)	(203,966)
CWIP Ending Balance	315,035	321,201	327,367	333,533	339,699	345,865	352,031	358,197	364,363	370,529	376,695	179,895	179,895
Electric Other Production Plant													
CWIP Beginning Balance	20,992,579	22,330,287	23,689,097	28,749,149	30,073,777	31,155,226	33,128,698	34,492,851	35,751,697	37,001,541	74,298,093	75,137,344	20,992,579
CWIP Expenditures	1,924,356	1,836,483	5,572,182	1,304,428	1,346,183	1,941,300	1,331,718	1,331,075	1,320,062	37,899,395	1,101,447	2,000,418	58,909,047
AFUDC Debt	32,370	34,384	39,181	43,953	45,766	48,034	50,527	52,492	54,366	83,194	111,686	113,688	709,641
AFUDC Equity	75,457	80,154	91,335	102,459	106,684	111,972	117,785	122,364	126,734	193,935	260,352	265,019	1,654,250
Closings to Plant	(694,476)	(592,211)	(642,646)	(126,212)	(417,184)	(127,833)	(135,876)	(247,086)	(251,318)	(879,972)	(634,235)	(544,421)	(5,293,468)
CWIP Ending Balance	22,330,287	23,689,097	28,749,149	30,073,777	31,155,226	33,128,698	34,492,851	35,751,697	37,001,541	74,298,093	75,137,344	76,972,048	76,972,048
Electric Transmission Plant													
CWIP Beginning Balance	9,984,699	10,535,770	11,089,591	11,646,175	12,205,537	12,767,690	13,332,649	13,900,426	14,471,037	15,044,495	15,620,814	16,200,010	9,984,699
CWIP Expenditures	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	6,000,000
AFUDC Debt	15,332	16,157	16,987	17,820	18,658	19,501	20,347	21,197	22,052	22,911	23,774	24,642	239,379
AFUDC Equity	35,740	37,664	39,598	41,541	43,495	45,458	47,431	49,413	51,406	53,408	55,421	57,443	558,018
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	10,535,770	11,089,591	11,646,175	12,205,537	12,767,690	13,332,649	13,900,426	14,471,037	15,044,495	15,620,814	16,200,010	16,782,095	16,782,095
Dispatchable													
Electric General Plant													
CWIP Beginning Balance	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665
CWIP Expenditures	13,561	6,061	6,061	18,561	11,061	11,061	11,061	6,061	6,061	6,061	6,061	3,333	105,000
Closings to Plant	(13,561)	(6,061)	(6,061)	(18,561)	(11,061)	(11,061)	(11,061)	(6,061)	(6,061)	(6,061)	(6,061)	(3,333)	(105,000)
CWIP Ending Balance	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665	8,665
Electric Other Production Plant													
CWIP Beginning Balance	30,314,745	37,174,525	44,084,782	52,561,833	61,278,420	68,292,654	75,425,219	82,611,288	102,918,707	113,020,105	121,043,954	123,519,042	30,314,745
CWIP Expenditures	6,696,749	6,713,537	8,242,407	8,504,579	6,784,438	6,801,036	6,816,494	19,964,059	9,664,807	8,370,378	7,439,947	6,696,113	102,694,544
AFUDC Debt	50,799	61,087	72,584	85,444	97,189	107,754	118,452	139,005	161,718	175,305	183,163	190,222	1,442,722
AFUDC Equity	118,418	142,401	169,201	199,180	226,558	251,186	276,125	324,036	376,983	408,654	426,973	443,428	3,363,142
Closings to Plant	(6,186)	(6,768)	(7,141)	(72,616)	(93,951)	(27,411)	(25,002)	(119,680)	(102,111)	(930,488)	(5,574,994)	(291,903)	(7,258,251)
CWIP Ending Balance	37,174,525	44,084,782	52,561,833	61,278,420	68,292,654	75,425,219	82,611,288	102,918,707	113,020,105	121,043,954	123,519,042	130,556,903	130,556,903
Electric Steam Production Plant													
CWIP Beginning Balance	3,721,484	4,320,831	2,156,146	1,602,292	1,635,670	1,676,477	1,873,703	1,957,351	2,101,009	2,489,140	2,424,193	2,677,719	3,721,484
CWIP Expenditures	785,300	259,000	623,200	193,300	106,500	203,200	280,800	178,000	429,800	207,800	431,150	258,700	3,956,750
AFUDC Debt	6,016	4,878	3,024	2,421	2,479	2,654	2,887	3,036	3,434	3,691	3,828	4,098	42,446
AFUDC Equity	14,024	11,371	7,049	5,644	5,779	6,186	6,729	7,077	8,006	8,605	8,924	9,553	98,946
Closings to Plant	(205,993)	(2,439,933)	(1,187,126)	(167,988)	(73,951)	(14,814)	(206,768)	(44,455)	(53,110)	(285,043)	(190,377)	(158,622)	(5,028,179)
CWIP Ending Balance	4,320,831	2,156,146	1,602,292	1,635,670	1,676,477	1,873,703	1,957,351	2,101,009	2,489,140	2,424,193	2,677,719	2,791,447	2,791,447

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Gardner													
Dry Cask Storage													
Electric Intangible Plant													
CWIP Beginning Balance	760,644	814,564	868,753	923,213	977,945	1,032,950	1,088,229	1,168,846	1,249,866	1,331,290	1,413,120	1,495,359	760,644
CWIP Expenditures	50,000	50,000	50,000	50,000	50,000	50,000	75,000	75,000	75,000	75,000	75,000	75,000	750,000
AFUDC Debt	1,177	1,258	1,339	1,420	1,502	1,585	1,686	1,807	1,928	2,050	2,173	2,296	20,223
AFUDC Equity	2,743	2,932	3,121	3,311	3,502	3,694	3,931	4,213	4,495	4,780	5,066	5,353	47,141
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	814,564	868,753	923,213	977,945	1,032,950	1,088,229	1,168,846	1,249,866	1,331,290	1,413,120	1,495,359	1,578,008	1,578,008
Electric Nuclear Production Plant													
CWIP Beginning Balance	19,205,443	19,553,550	19,872,178	24,548,339	24,814,146	25,087,777	25,362,183	25,666,724	25,963,240	33,037,971	34,811,700	35,223,562	19,205,443
CWIP Expenditures	251,644	220,505	4,565,608	142,954	149,436	148,846	177,541	168,020	6,927,889	1,604,866	237,559	609,687	15,204,555
AFUDC Debt	28,958	29,456	33,188	36,880	37,284	37,693	38,126	38,575	44,082	50,693	52,326	53,222	480,482
AFUDC Equity	67,505	68,666	77,365	85,972	86,912	87,866	88,875	89,922	102,760	118,171	121,977	124,065	1,120,056
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	19,553,550	19,872,178	24,548,339	24,814,146	25,087,777	25,362,183	25,666,724	25,963,240	33,037,971	34,811,700	35,223,562	36,010,536	36,010,536
Facilities & Other													
Electric General Plant													
CWIP Beginning Balance	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765
CWIP Expenditures	500	500	500	500	10,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	100,000
Closings to Plant	(500)	(500)	(500)	(500)	(10,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(100,000)
CWIP Ending Balance	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765	114,765
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	973,212	978,570	983,954	989,365	1,017,081	1,080,023	1,145,283	1,210,869	1,276,783	1,343,025	1,409,598	1,476,503	973,212
CWIP Expenditures	500	500	500	22,722	57,722	59,722	59,722	59,722	59,722	59,722	59,722	59,722	500,000
AFUDC Debt	1,458	1,466	1,474	1,499	1,567	1,663	1,760	1,859	1,957	2,057	2,156	2,112	21,029
AFUDC Equity	3,399	3,418	3,437	3,495	3,652	3,876	4,104	4,333	4,563	4,794	5,027	4,924	49,021
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(204,068)	(204,068)
CWIP Ending Balance	978,570	983,954	989,365	1,017,081	1,080,023	1,145,283	1,210,869	1,276,783	1,343,025	1,409,598	1,476,503	1,339,194	1,339,194
Improvements													
Electric General Plant													
CWIP Beginning Balance	700,000	717,167	734,333	751,500	779,778	808,056	836,333	868,111	935,889	1,013,667	1,093,445	1,121,722	700,000
CWIP Expenditures	17,167	17,167	17,167	28,278	28,278	28,278	31,778	67,778	77,778	79,778	28,278	28,278	450,000
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(100,000)	(100,000)
CWIP Ending Balance	717,167	734,333	751,500	779,778	808,056	836,333	868,111	935,889	1,013,667	1,093,445	1,121,722	1,050,000	1,050,000
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	26,939,056	27,476,071	28,015,765	28,563,165	29,123,322	29,700,309	30,330,300	31,419,569	31,820,251	32,432,935	33,492,597	34,557,546	26,939,056
CWIP Expenditures	406,655	402,839	406,834	416,834	430,834	480,834	935,834	700,834	740,834	975,834	947,834	792,197	7,638,200
AFUDC Debt	40,581	41,386	42,198	43,025	43,875	44,777	46,061	47,177	47,960	49,181	50,768	48,965	545,955
AFUDC Equity	94,599	96,475	98,368	100,297	102,277	104,380	107,374	109,975	111,800	114,646	118,347	114,142	1,272,680
Closings to Plant	(4,820)	(1,004)	-	-	-	-	-	(457,305)	(287,911)	(80,000)	(52,000)	(4,641,777)	(5,524,817)
CWIP Ending Balance	27,476,071	28,015,765	28,563,165	29,123,322	29,700,309	30,330,300	31,419,569	31,820,251	32,432,935	33,492,597	34,557,546	30,871,073	30,871,073
Mandated Compliance													
Electric Intangible Plant													
CWIP Beginning Balance	16,884,580	17,407,927	17,833,636	18,497,146	19,242,525	19,677,388	20,114,422	20,553,636	21,152,160	21,696,802	22,143,913	22,593,254	16,884,580
CWIP Expenditures	438,000	338,000	573,090	651,453	338,000	338,000	338,000	494,727	438,000	338,000	338,000	738,000	5,361,270
AFUDC Debt	25,621	26,330	27,144	28,197	29,078	29,730	30,385	31,160	32,014	32,755	33,425	34,397	360,236
AFUDC Equity	59,726	61,379	63,276	65,729	67,785	69,304	70,830	72,637	74,628	76,355	77,917	80,184	839,749
CWIP Ending Balance	17,407,927	17,833,636	18,497,146	19,242,525	19,677,388	20,114,422	20,553,636	21,152,160	21,696,802	22,143,913	22,593,254	23,445,836	23,445,836

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Electric Nuclear Production Plant													
CWIP Beginning Balance	2,103,192	2,114,189	2,125,240	2,136,346	2,258,896	2,504,863	2,754,062	3,004,505	3,256,198	3,509,147	3,763,358	4,018,837	2,103,192
CWIP Expenditures	500	500	500	111,611	234,111	236,111	236,111	236,111	236,111	236,111	236,111	236,111	2,000,000
AFUDC Debt	3,151	3,167	3,184	3,284	3,559	3,929	4,302	4,678	5,055	5,434	5,814	5,476	51,033
AFUDC Equity	7,345	7,384	7,422	7,655	8,297	9,159	10,029	10,904	11,783	12,666	13,554	12,766	118,964
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(1,020,338)	(1,020,338)
CWIP Ending Balance	2,114,189	2,125,240	2,136,346	2,258,896	2,504,863	2,754,062	3,004,505	3,256,198	3,509,147	3,763,358	4,018,837	3,252,852	3,252,852
Nuclear Fuel													
Nuclear Fuel													
CWIP Beginning Balance	69,507,028	70,222,405	74,592,160	78,110,781	78,614,788	86,407,846	93,071,627	97,452,579	100,833,742	32,788,428	32,974,634	33,168,507	69,507,028
CWIP Expenditures	367,619	4,009,342	3,138,576	113,949	7,382,352	6,217,094	3,906,777	2,887,670	1,818,883	24,011	598,566	52,536,805	83,001,644
AFUDC Debt	104,397	108,196	114,090	117,095	123,294	134,096	142,347	148,147	122,115	49,134	49,418	89,036	1,301,366
AFUDC Equity	243,360	252,217	265,956	272,962	287,412	312,591	331,827	345,346	284,664	114,537	115,199	207,554	3,033,625
Closings to Plant	-	-	-	-	-	-	-	-	(70,270,977)	(1,475)	(569,310)	-	(70,841,762)
CWIP Ending Balance	70,222,405	74,592,160	78,110,781	78,614,788	86,407,846	93,071,627	97,452,579	100,833,742	32,788,428	32,974,634	33,168,507	86,001,902	86,001,902
Reliability													
Electric General Plant													
CWIP Beginning Balance	700,000	750,000	800,000	1,050,000	1,311,111	1,822,222	2,333,333	2,844,444	255,556	266,667	277,778	288,889	700,000
CWIP Expenditures	61,000	61,000	276,000	342,667	643,917	647,917	697,917	797,917	502,917	302,917	229,917	188,588	4,752,671
Closings to Plant	(11,000)	(11,000)	(26,000)	(81,556)	(132,806)	(136,806)	(186,806)	(3,386,806)	(491,806)	(291,806)	(218,806)	(177,477)	(5,152,671)
CWIP Ending Balance	750,000	800,000	1,050,000	1,311,111	1,822,222	2,333,333	2,844,444	255,556	266,667	277,778	288,889	300,000	300,000
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Nuclear Production Plant													
CWIP Beginning Balance	26,802,121	28,628,033	30,446,313	32,199,946	35,600,220	39,385,850	43,129,111	52,848,882	58,202,332	61,263,312	64,088,593	62,141,212	26,802,121
CWIP Expenditures	1,692,958	1,676,257	2,563,256	3,255,401	3,616,906	3,762,111	9,664,729	5,077,566	7,482,228	10,039,017	5,704,844	5,209,470	59,744,742
AFUDC Debt	41,414	44,137	46,897	50,656	56,025	61,650	71,709	82,970	89,640	94,627	94,755	77,320	811,801
AFUDC Equity	96,540	102,887	109,323	118,084	130,600	143,714	167,161	193,413	208,961	220,587	220,884	180,241	1,892,395
Closings to Plant	(5,000)	(5,000)	(965,843)	(23,868)	(17,900)	(224,214)	(183,827)	(500)	(4,719,849)	(7,528,950)	(7,967,864)	(27,424,344)	(49,067,159)
CWIP Ending Balance	28,628,033	30,446,313	32,199,946	35,600,220	39,385,850	43,129,111	52,848,882	58,202,332	61,263,312	64,088,593	62,141,212	40,183,899	40,183,899
Husen													
Replacements, Additions, & Repairs													
Electric General Plant													
CWIP Beginning Balance	387,979	362,585	310,510	355,257	532,880	772,016	890,411	976,088	914,261	837,168	751,218	642,052	387,979
CWIP Expenditures	627,846	902,769	2,737,230	4,266,845	4,953,845	3,983,845	3,583,076	3,607,076	981,694	900,615	1,259,615	333,623	28,138,079
Closings to Plant	(653,240)	(954,845)	(2,692,483)	(4,089,222)	(4,714,709)	(3,865,450)	(3,497,399)	(3,668,902)	(1,058,787)	(986,565)	(1,368,780)	(497,749)	(28,048,131)
CWIP Ending Balance	362,585	310,510	355,257	532,880	772,016	890,411	976,088	914,261	837,168	751,218	642,052	477,927	477,927
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	218,108	162,717	149,433	110,251	98,912	89,916	100,324	72,014	76,520	54,569	27,643	19,350	218,108
CWIP Expenditures	-	40,000	51,667	55,000	125,000	150,000	50,000	85,386	50,000	50,000	-	50,000	707,053
Closings to Plant	(55,391)	(53,284)	(90,848)	(66,339)	(133,997)	(139,592)	(78,310)	(80,880)	(71,951)	(76,926)	(8,293)	(20,805)	(876,616)
CWIP Ending Balance	162,717	149,433	110,251	98,912	89,916	100,324	72,014	76,520	54,569	27,643	19,350	48,545	48,545
Electric General Plant													
CWIP Beginning Balance	17,233	47,063	46,944	53,861	107,703	187,392	236,174	284,322	290,025	291,918	241,442	204,010	17,233
CWIP Expenditures	50,000	20,000	30,000	100,000	160,000	150,000	170,000	130,000	127,000	53,000	50,000	16,000	1,056,000
Closings to Plant	(20,170)	(20,119)	(23,083)	(46,158)	(80,311)	(101,218)	(121,852)	(124,297)	(125,108)	(103,475)	(87,433)	(66,003)	(919,226)
CWIP Ending Balance	47,063	46,944	53,861	107,703	187,392	236,174	284,322	290,025	291,918	241,442	204,010	154,007	154,007
PHEV													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	38,950	178,950	-	-	217,900
Closings to Plant	-	-	-	-	-	-	-	-	(38,950)	(178,950)	-	-	(217,900)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Expenditures	-	-	-	-	-	-	-	-	707,900	668,950	140,000	-	1,516,850
Closings to Plant	-	-	-	-	-	-	-	-	(707,900)	(668,950)	(140,000)	-	(1,516,850)

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Fueling Depots													
Common General Plant													
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
Moeller													
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	4,940,891	5,108,976	5,277,900	5,447,667	5,618,281	5,789,746	5,962,067	6,135,247	6,309,292	6,484,206	6,659,992	6,836,655	4,940,891
CWIP Expenditures	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	143,073	1,716,876
AFUDC Debt	7,509	7,760	8,013	8,268	8,523	8,780	9,038	9,298	9,558	9,821	10,084	10,348	107,001
AFUDC Equity	17,503	18,090	18,680	19,273	19,869	20,468	21,069	21,674	22,282	22,893	23,507	24,123	249,431
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	5,108,976	5,277,900	5,447,667	5,618,281	5,789,746	5,962,067	6,135,247	6,309,292	6,484,206	6,659,992	6,836,655	7,014,200	7,014,200
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Enterprise Security Capital													
Common General Plant													
CWIP Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Hydro Production Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Other													
Common General Plant													
CWIP Beginning Balance	576	576	576	576	576	576	576	576	576	576	576	576	576
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	576	576	576	576	576	576	576	576	576	576	576	576	576
Common Intangible Plant													
CWIP Beginning Balance	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806	270,806
Electric Distribution Plant													
CWIP Beginning Balance	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)	(21,896,668)
Electric General Plant													
CWIP Beginning Balance	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563	180,563

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Electric Intangible Plant													
CWIP Beginning Balance	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)	(183,742)
Electric Other Production Plant													
CWIP Beginning Balance	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537	22,664,537
Electric Steam Production Plant													
CWIP Beginning Balance	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167	30,167
Electric Transmission Plant													
CWIP Beginning Balance	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)	(2,669)
Property Services Capital													
Common General Plant													
CWIP Beginning Balance	616,166	507,580	423,048	399,738	506,545	972,520	1,496,135	1,890,183	2,233,451	2,579,361	2,924,619	3,214,536	616,166
CWIP Expenditures	1,000	3,000	59,000	206,500	595,353	701,331	583,316	529,616	529,616	526,463	460,962	459,509	4,655,666
AFUDC Debt	840	696	620	690	1,125	1,874	2,550	3,097	3,612	4,128	4,600	3,137	26,970
AFUDC Equity	1,958	1,622	1,445	1,610	2,622	4,369	5,945	7,219	8,419	9,623	10,723	7,313	62,869
Closings to Plant	(112,385)	(89,850)	(84,375)	(101,993)	(133,126)	(183,960)	(197,764)	(196,664)	(195,737)	(194,957)	(186,367)	(2,878,752)	(4,555,928)
CWIP Ending Balance	507,580	423,048	399,738	506,545	972,520	1,496,135	1,890,183	2,233,451	2,579,361	2,924,619	3,214,536	805,742	805,742
Electric General Plant													
CWIP Beginning Balance	34,118,426	41,908,657	49,739,069	50,942,660	52,484,997	55,233,252	57,977,989	59,918,849	61,833,192	63,242,236	64,206,890	64,819,393	34,118,426
CWIP Expenditures	7,606,700	7,606,700	956,700	1,324,043	2,569,443	2,599,883	1,855,884	1,822,286	1,307,272	824,604	455,211	303,412	29,232,138
AFUDC Debt	56,803	68,474	75,223	77,288	80,503	84,613	88,131	91,003	93,486	95,248	96,426	87,200	994,397
AFUDC Equity	132,413	159,619	175,354	180,167	187,661	197,243	205,442	212,137	217,925	222,033	224,780	203,273	2,318,048
Closings to Plant	(5,685)	(4,382)	(3,685)	(39,163)	(89,351)	(137,003)	(208,597)	(211,082)	(209,639)	(177,230)	(163,914)	(13,682,157)	(14,931,889)
CWIP Ending Balance	41,908,657	49,739,069	50,942,660	52,484,997	55,233,252	57,977,989	59,918,849	61,833,192	63,242,236	64,206,890	64,819,393	51,731,121	51,731,121
Fleet, Tools and Communications													
Common General Plant													
CWIP Beginning Balance	289,753	226,008	176,286	176,503	137,672	107,384	122,760	95,753	105,887	168,392	178,146	170,154	289,753
CWIP Expenditures	-	-	50,000	-	-	50,000	-	40,000	110,000	60,000	40,000	40,000	390,000
Closings to Plant	(63,746)	(49,722)	(49,783)	(38,831)	(30,288)	(34,625)	(27,007)	(29,866)	(47,495)	(50,246)	(47,992)	(46,234)	(515,834)
CWIP Ending Balance	226,008	176,286	176,503	137,672	107,384	122,760	95,753	105,887	168,392	178,146	170,154	163,920	163,920
Electric General Plant													
CWIP Beginning Balance	2,771	2,162	1,686	1,315	1,026	800	624	487	380	296	231	180	2,771
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(610)	(476)	(371)	(289)	(226)	(176)	(137)	(107)	(84)	(65)	(51)	(40)	(2,631)
CWIP Ending Balance	2,162	1,686	1,315	1,026	800	624	487	380	296	231	180	141	141
Remington													
Aging Technology													
Common General Plant													
CWIP Beginning Balance	174,419	1,947,291	3,720,552	1,046,607	3,515,326	5,999,178	3,420,642	5,904,651	8,578,705	5,795,312	8,359,419	11,088,543	174,419
CWIP Expenditures	1,847,072	1,847,076	2,826,076	2,542,076	2,557,076	2,786,076	2,557,076	2,747,076	2,557,076	2,637,076	2,802,076	2,582,076	30,287,912
Closings to Plant	(74,201)	(73,816)	(5,500,021)	(73,357)	(73,225)	(5,364,611)	(73,068)	(73,022)	(5,340,470)	(72,968)	(72,953)	(13,170,619)	(29,962,331)
CWIP Ending Balance	1,947,291	3,720,552	1,046,607	3,515,326	5,999,178	3,420,642	5,904,651	8,578,705	5,795,312	8,359,419	11,088,543	500,000	500,000
Common Intangible Plant													
CWIP Beginning Balance	3,762,880	4,311,918	4,863,278	5,713,805	6,568,157	7,426,354	8,288,415	9,154,360	10,024,208	10,897,977	11,775,689	12,657,361	3,762,880
CWIP Expenditures	529,151	529,151	825,246	825,246	825,246	825,246	825,246	825,246	825,246	825,246	825,246	825,246	9,310,758
AFUDC Debt	5,970	6,667	7,589	8,738	9,892	11,052	12,218	13,389	14,567	15,750	16,939	10,179	132,952
AFUDC Equity	13,918	15,542	17,692	20,369	23,060	25,764	28,481	31,212	33,957	36,716	39,488	23,728	309,925
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(11,962,151)	(11,962,151)
CWIP Ending Balance	4,311,918	4,863,278	5,713,805	6,568,157	7,426,354	8,288,415	9,154,360	10,024,208	10,897,977	11,775,689	12,657,361	1,554,363	1,554,363
Electric General Plant													
CWIP Beginning Balance	6,439,304	6,691,119	6,943,928	7,039,935	7,314,747	7,530,568	7,649,603	7,867,457	8,146,335	8,268,443	8,484,385	8,746,366	6,439,304
CWIP Expenditures	219,267	219,267	243,267	239,267	179,267	263,267	179,267	239,267	219,267	174,267	219,267	279,258	2,674,191
AFUDC Debt	9,771	10,069	10,369	10,671	10,974	11,278	11,584	11,891	12,200	12,511	12,823	13,137	137,278
AFUDC Equity	22,777	23,473	24,172	24,874	25,581	26,290	27,003	27,720	28,440	29,164	29,892	30,623	320,010
Closings to Plant	-	-	(181,800)	-	-	(181,800)	-	-	(137,800)	-	-	(172,791)	(674,191)
CWIP Ending Balance	6,691,119	6,943,928	7,039,935	7,314,747	7,530,568	7,649,603	7,867,457	8,146,335	8,268,443	8,484,385	8,746,366	8,896,593	8,896,593
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
AGIS													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	50,000	50,000	50,000	150,000
AFUDC Debt	-	-	-	-	-	-	-	-	-	19	19	19	56
AFUDC Equity	-	-	-	-	-	-	-	-	-	44	44	44	131
Closings to Plant	-	-	-	-	-	-	-	-	-	(50,062)	(50,062)	(50,062)	(150,187)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	-	-	1,818,000	-	-	-	-	10,000	61,000	137,000	258,000	403,000	-
CWIP Expenditures	5,846,399	1,818,000	-	-	-	-	10,000	51,000	76,000	121,000	145,000	157,001	8,224,400
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(5,846,399)	-	(1,818,000)	-	-	-	-	-	-	-	-	(1)	(7,664,400)
CWIP Ending Balance	-	1,818,000	-	-	-	-	10,000	61,000	137,000	258,000	403,000	560,000	560,000
Cyber Security													
Common General Plant													
CWIP Beginning Balance	-	62,500	125,000	149,830	362,160	574,490	599,320	811,651	1,023,981	1,048,811	1,261,141	1,473,471	-
CWIP Expenditures	62,500	62,500	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	2,248,301
Closings to Plant	-	-	(187,500)	-	-	(187,500)	-	-	(187,500)	-	-	(1,685,801)	(2,248,301)
CWIP Ending Balance	62,500	125,000	149,830	362,160	574,490	599,320	811,651	1,023,981	1,048,811	1,261,141	1,473,471	-	-
Common Intangible Plant													
CWIP Beginning Balance	5,725,131	5,847,803	5,976,020	6,108,328	6,243,714	6,381,468	6,521,092	6,662,243	6,804,678	6,948,230	7,092,783	7,238,256	5,725,131
CWIP Expenditures	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	1,229,733	14,756,796
AFUDC Debt	4,786	4,994	5,203	5,413	5,625	5,837	6,050	6,264	6,480	6,696	6,914	7,132	71,395
AFUDC Equity	11,158	11,642	12,130	12,619	13,111	13,606	14,103	14,603	15,105	15,609	16,116	16,626	166,429
Closings to Plant	(1,123,005)	(1,118,153)	(1,114,757)	(1,112,380)	(1,110,716)	(1,109,551)	(1,108,736)	(1,108,165)	(1,107,765)	(1,107,486)	(1,107,290)	(1,107,153)	(13,335,156)
CWIP Ending Balance	5,847,803	5,976,020	6,108,328	6,243,714	6,381,468	6,521,092	6,662,243	6,804,678	6,948,230	7,092,783	7,238,256	7,384,594	7,384,594
Electric General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergent Demand													
Common General Plant													
CWIP Beginning Balance	5,040,098	5,126,116	5,203,532	5,273,206	5,335,913	5,392,350	5,443,142	5,488,856	5,529,998	5,567,026	5,600,351	5,630,344	5,040,098
CWIP Expenditures	655,586	655,586	655,586	655,586	655,586	655,586	655,586	655,586	655,586	655,586	655,586	655,586	7,867,036
Closings to Plant	(569,568)	(578,170)	(585,912)	(592,879)	(599,150)	(604,794)	(609,873)	(614,444)	(618,558)	(622,261)	(625,594)	(628,593)	(7,249,797)
CWIP Ending Balance	5,126,116	5,203,532	5,273,206	5,335,913	5,392,350	5,443,142	5,488,856	5,529,998	5,567,026	5,600,351	5,630,344	5,657,337	5,657,337
Common Intangible Plant													
CWIP Beginning Balance	(304,958)	206,874	565,156	815,953	991,512	1,114,402	1,200,426	1,260,642	1,302,794	1,332,300	1,352,954	1,367,412	(304,958)
CWIP Expenditures	600,492	600,492	600,492	600,492	600,492	600,492	600,492	600,492	600,492	600,492	600,492	600,492	7,205,901
Closings to Plant	(88,660)	(242,210)	(349,694)	(424,934)	(477,601)	(514,468)	(540,275)	(558,340)	(570,986)	(579,837)	(586,034)	(590,371)	(5,523,410)
CWIP Ending Balance	206,874	565,156	815,953	991,512	1,114,402	1,200,426	1,260,642	1,302,794	1,332,300	1,352,954	1,367,412	1,377,533	1,377,533
Enhance Capabilities													
Common General Plant													
CWIP Beginning Balance	-	41,667	83,333	125,000	166,667	208,333	250,000	291,667	333,333	375,000	416,667	458,333	-
CWIP Expenditures	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	291,667	750,000
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(250,000)	(250,000)
CWIP Ending Balance	41,667	83,333	125,000	166,667	208,333	250,000	291,667	333,333	375,000	416,667	458,333	500,000	500,000
Common Intangible Plant													
CWIP Beginning Balance	7,759,694	8,547,981	9,340,201	10,484,290	11,634,088	12,150,324	13,181,846	14,218,515	15,260,356	16,307,397	17,359,662	18,417,178	7,759,694
CWIP Expenditures	747,700	747,700	1,094,750	1,094,750	1,094,750	968,475	968,475	968,475	968,475	968,475	968,475	968,475	11,558,975
AFUDC Debt	12,184	13,365	14,812	16,525	17,818	18,927	20,472	22,025	23,585	25,154	26,730	20,264	231,861
AFUDC Equity	28,402	31,155	34,527	38,523	41,537	44,120	47,722	51,342	54,980	58,636	62,311	47,238	540,493
Closings to Plant	-	-	-	-	(637,868)	-	-	-	-	-	-	(11,240,289)	(11,878,158)
CWIP Ending Balance	8,547,981	9,340,201	10,484,290	11,634,088	12,150,324	13,181,846	14,218,515	15,260,356	16,307,397	17,359,662	18,417,178	8,212,866	8,212,866

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2024 Year-to-date
Electric General Plant													
CWIP Beginning Balance	600,000	629,167	658,333	687,500	716,667	745,833	775,000	804,167	833,333	862,500	891,666	920,833	600,000
CWIP Expenditures	29,167	29,167	29,167	29,167	29,167	29,167	29,167	29,167	29,167	29,167	29,167	29,167	350,000
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(200,000)	(200,000)
CWIP Ending Balance	629,167	658,333	687,500	716,667	745,833	775,000	804,167	833,333	862,500	891,666	920,833	750,000	750,000
Electric Intangible Plant													
CWIP Beginning Balance	3,114,402	3,235,139	3,356,478	3,587,695	3,820,065	4,053,595	4,288,291	4,524,157	4,761,200	4,999,427	5,238,842	5,479,451	3,114,402
CWIP Expenditures	104,934	104,934	213,934	213,934	213,934	213,934	213,934	213,934	213,934	213,934	213,934	213,934	2,349,209
AFUDC Debt	4,744	4,925	5,188	5,535	5,883	6,233	6,584	6,937	7,293	7,649	8,008	4,319	73,297
AFUDC Equity	11,059	11,480	12,094	12,902	13,713	14,529	15,348	16,172	17,000	17,832	18,668	10,067	170,863
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	(5,526,144)	(5,526,144)
CWIP Ending Balance	3,235,139	3,356,478	3,587,695	3,820,065	4,053,595	4,288,291	4,524,157	4,761,200	4,999,427	5,238,842	5,479,451	181,628	181,628
Customer													
Common General Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Common Intangible Plant													
CWIP Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
CWIP Expenditures	42,476	42,288	42,288	41,553	41,178	41,178	30,683	30,683	30,683	30,683	30,683	30,683	435,059
AFUDC Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
AFUDC Equity	-	-	-	-	-	-	-	-	-	-	-	-	-
Closings to Plant	(42,476)	(42,288)	(42,288)	(41,553)	(41,178)	(41,178)	(30,683)	(30,683)	(30,683)	(30,683)	(30,683)	(30,683)	(435,059)
CWIP Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

Northern States Power Company
Expenditures and Additions by Witness
Capital Expenditures Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 4
Page 1 of 4

Total Company

Witness	Major category	Functional Class	2021 CWIP spend	2021 RWIP spend	2021 Total	2022 CWIP spend	2022 RWIP spend	2022 Total	2023 CWIP spend	2023 RWIP spend	2023 Total	2024 CWIP spend	2024 RWIP spend	2024 Total	Grand Total
Benson	Asset Renewal	Electric General Plant	10,533,699	336,313	10,870,012	10,222,739	20,000	10,242,739	9,526,040	20,000	9,546,040	6,133,996	19,992	6,153,988	**36,812,779**
Benson	Asset Renewal	Electric Transmission Plant	76,337,880	6,033,211	82,371,090	175,531,643	2,952,353	178,483,996	168,141,725	2,825,514	170,967,239	163,766,122	2,961,233	166,727,355	**598,549,680**
Benson	Comm Infrastructure	Electric General Plant	4,088,157	1,813	4,089,969	9,730,346	119,936	9,850,282	23,800,900	476,785	24,277,685	25,441,742	515,747	25,957,489	**64,175,425**
Benson	Comm Infrastructure	Electric Transmission Plant	5,095,294	94,485	5,189,779	18,789,592	383,260	19,172,852	318,500	6,500	325,000				**24,687,631**
Benson	Interconnection	Electric General Plant	527,486		527,486										**527,486**
Benson	Interconnection	Electric Transmission Plant	41,284,752	523,002	41,807,754	6,708,118	9,782	6,717,900	18,926,634	73,365	19,000,000	28,985,327	14,673	29,000,000	**96,525,654**
Benson	Regional Expansion	Electric General Plant	117,539		117,539										**117,539**
Benson	Regional Expansion	Electric Transmission Plant	18,576,073	140,319	18,716,392	13,342,598	65,800	13,408,398	23,434,900	266,200	23,701,100	43,211,938	422,900	43,634,838	**99,460,728**
Benson	Reliability Requirement	Electric General Plant	306,425	(131,232)	175,193	343,001	7,000	350,001							**525,194**
Benson	Reliability Requirement	Electric Transmission Plant	48,039,871	(1,593,193)	46,446,678	20,979,971	328,060	21,308,031	38,477,018	370,752	38,847,770	51,992,522	615,000	52,607,522	**159,210,001**
Benson	Security\Resiliency	Electric General Plant	2,495,033	13,220	2,508,253	12,598,289	135,720	12,734,009	8,125,924	36,080	8,162,004	5,670,400		5,670,400	**29,074,666**
Benson	Security\Resiliency	Electric Intangible Plant				744,000		744,000	1,023,000		1,023,000	1,860,000		1,860,000	**3,627,000**
Benson	Security\Resiliency	Electric Transmission Plant	19,381,685	827,292	20,208,977	31,371,876	435,760	31,807,636	26,247,954	156,080	26,404,034	9,000,047		9,000,047	**87,420,694**
Benson Total			**226,783,893**	**6,245,229**	**233,029,122**	**300,362,173**	**4,457,671**	**304,819,844**	**318,022,595**	**4,231,276**	**322,253,872**	**336,062,094**	**4,549,545**	**340,611,639**	**1,200,714,477**
Bloch	AGIS	Electric Distribution Plant	8,218,349	350,945	8,569,294	79,269,483	3,562,638	82,832,120	117,393,869	4,255,812	121,649,681	101,310,112	2,337,997	103,648,109	**316,699,204**
Bloch	AGIS	Electric General Plant	5,651,824	730	5,652,554	9,196,896	1,464	9,198,360	15,184,400	1,104	15,185,504	12,953,483	1,104	12,954,587	**42,991,005**
Bloch	AGIS	Electric Intangible Plant	1,629,853		1,629,853	2,205,828		2,205,828	3,920,008		3,920,008	1,919,312		1,919,312	**9,675,001**
Bloch	Asset Health & Reliability	Electric Distribution Plant	134,254,957	11,316,573	145,571,530	178,739,632	12,154,376	190,894,008	191,489,560	13,380,440	204,870,000	197,833,009	14,259,964	212,092,973	**753,428,511**
Bloch	Asset Health & Reliability	Electric General Plant	99,098	4,480	103,578	163,676	12,324	176,000	198,088	14,912	213,000	204,600	15,400	220,000	**712,578**
Bloch	Capacity	Electric Distribution Plant	32,257,069	337,314	32,594,383	38,177,994	745,000	38,922,994	39,273,388	928,616	40,202,004	49,582,580	1,320,420	50,903,000	**162,622,381**
Bloch	Capacity	Electric General Plant							700,000		700,000				**700,000**
Bloch	Electric Vehicles	Electric Distribution Plant	7,667,675	7,325	7,675,000	94,120,000		94,120,000	63,100,000		63,100,000	59,073,000		59,073,000	**223,968,000**
Bloch	Fleet, Tools and Communications	Common General Plant	421,013	3,000	424,013	343,488	3,512	347,000	353,400	3,600	357,000	365,276	3,724	369,000	**1,497,013**
Bloch	Fleet, Tools and Communications	Common Intangible Plant	605		605										**605**
Bloch	Fleet, Tools and Communications	Electric Distribution Plant	3,447,366	120,469	3,567,835	400,000		400,000	400,000		400,000	400,000		400,000	**4,767,835**
Bloch	Fleet, Tools and Communications	Electric General Plant	7,593,606	185,761	7,779,367	15,924,158	160,864	16,085,022	16,737,862	169,084	16,906,946	15,284,622	154,391	15,439,013	**56,210,348**
Bloch	Mandates	Electric Distribution Plant	25,861,530	2,461,507	28,323,036	30,299,928	2,068,072	32,368,000	30,341,580	1,870,424	32,212,004	34,709,716	1,907,284	36,617,000	**129,520,040**
Bloch	New Business	Electric Distribution Plant	66,353,308	(158,478)	66,194,830	60,204,260	482,700	60,686,960	61,495,116	452,884	61,948,000	61,469,960	380,040	61,850,000	**250,679,790**
Bloch	Solar	Electric Distribution Plant	(939,214)	(405,051)	(1,344,265)										**(1,344,265)**
Bloch	Solar	Electric General Plant	(85,394)		(85,394)										**(85,394)**
Bloch Total			**292,431,646**	**14,224,574**	**306,656,220**	**509,045,343**	**19,190,950**	**528,236,292**	**540,587,271**	**21,076,876**	**561,664,147**	**535,105,670**	**20,380,324**	**555,485,994**	**1,952,042,653**
Capra	Coal	Electric General Plant	197,189	(13)	197,176	446,000		446,000	350,000		350,000	350,000		350,000	**1,343,176**
Capra	Coal	Electric Steam Production Plant	22,616,492	3,177,918	25,794,411	11,828,498	10,030,265	21,858,763	12,170,579	1,552,000	13,722,579	10,044,370	5,439,283	15,483,653	**76,859,406**
Capra	Dispatchable	Electric General Plant	624,761		624,761	75,000		75,000	75,000		75,000	105,000		105,000	**879,761**
Capra	Dispatchable	Electric Other Production Plant	11,677,661	2,030,008	13,707,669	21,553,460	1,049,228	22,602,688	40,455,627	5,006,657	45,462,284	102,694,544	1,392,713	104,087,257	**185,859,898**
Capra	Dispatchable	Electric Steam Production Plant	8,545,062	930,773	9,475,835	12,548,157	2,510,959	15,059,116	7,215,500	564,500	7,780,000	3,956,750	566,500	4,523,250	**36,838,201**
Capra	Hydro	Electric General Plant	7,500		7,500	15,000		15,000	15,000		15,000	15,000		15,000	**52,500**
Capra	Hydro	Electric Hydro Production Plant	99,654	9,967	109,621	45,000		45,000	140,000		140,000	455,000		455,000	**749,621**
Capra	Intermediate	Electric General Plant	565,856		565,856	1,349,620	2,000	1,351,620	688,470		688,470	691,750		691,750	**3,297,696**
Capra	Intermediate	Electric Intangible Plant	1,190,770		1,190,770	149,640		149,640							**1,340,410**
Capra	Intermediate	Electric Other Production Plant	30,364,027	889,426	31,253,453	34,413,061	1,074,883	35,487,945	24,030,167	1,232,914	25,263,081	30,847,884	1,455,896	32,303,780	**124,308,259**
Capra	Solar	Electric Other Production Plant	11,831,471		11,831,471	172,256,451		172,256,451	279,582,058		279,582,058	316,775,174		316,775,174	**780,445,155**
Capra	Solar	Electric Transmission Plant				120,000		120,000	120,000		120,000	120,000		120,000	**360,000**
Capra	Wind	Electric General Plant	2,371,124		2,371,124	676,506	833	677,340	128,493		128,493	120,000		120,000	**3,296,957**
Capra	Wind	Electric Intangible Plant	301,882		301,882	553,992		553,992	108,495		108,495	74,992		74,992	**1,039,361**
Capra	Wind	Electric Other Production Plant	635,596,342	833,829	636,430,171	384,008,017	15,151,242	399,159,259	79,898,412	8,103,708	88,002,120	58,909,047	888,054	59,797,101	**1,183,388,650**
Capra	Wind	Electric Transmission Plant	21,283,043	(53,168)	21,229,875	3,500,000		3,500,000	6,000,000		6,000,000	6,000,000		6,000,000	**36,729,875**
Capra Total			**747,272,833**	**7,818,740**	**755,091,573**	**643,538,403**	**29,819,410**	**673,357,813**	**450,977,801**	**16,459,780**	**467,437,581**	**531,159,511**	**9,742,446**	**540,901,958**	**2,436,788,925**
Gardner	Dry Cask Storage	Electric Intangible Plant	120,000		120,000				750,000		750,000	750,000		750,000	**1,620,000**
Gardner	Dry Cask Storage	Electric Nuclear Production Plant	18,246,402		18,246,402	16,251,121		16,251,121	11,663,849		11,663,849	15,204,555		15,204,555	**61,365,927**
Gardner	Facilities & Other	Electric General Plant	421,310		421,310	100,000		100,000	700,000		700,000	100,000		100,000	**1,321,310**
Gardner	Facilities & Other	Electric Intangible Plant	711,000		711,000										**711,000**
Gardner	Facilities & Other	Electric Nuclear Production Plant	2,099,199	98,471	2,197,669	933,328	2,600,907	3,534,234	1,160,000		1,160,000	500,000		500,000	**7,391,904**
Gardner	Improvements	Electric General Plant	8,435,324	33,173	8,468,497	4,653,479		4,653,479	601,682		601,682	450,000		450,000	**14,173,658**
Gardner	Improvements	Electric Intangible Plant	8,290,991		8,290,991	1,309,538		1,309,538	265,074		265,074				**9,865,604**
Gardner	Improvements	Electric Nuclear Production Plant	6,495,370	35,953	6,531,323	10,687,491	2,000	10,689,491	14,344,313	24,235	14,368,548	7,638,200	5,000	7,643,200	**39,232,561**
Gardner	Mandated Compliance	Electric Intangible Plant	3,961,682		3,961,682	5,240,202		5,240,202	6,284,728		6,284,728	5,361,270		5,361,270	**20,847,882**
Gardner	Mandated Compliance	Electric Nuclear Production Plant	3,722,604	81,756	3,804,359	2,015,000		2,015,000	2,000,000		2,000,000	2,000,000		2,000,000	**9,819,359**
Gardner	Nuclear Fuel	Nuclear Fuel	104,685,752		104,685,752	86,822,216		86,822,216	104,376,912		104,376,912	83,001,644		83,001,644	**378,886,524**
Gardner	Reliability	Electric General Plant	2,123,674	7,555	2,131,229	4,246,580	36,600	4,283,180	2,150,000		2,150,000	4,752,671	10,000	4,762,671	**13,327,080**
Gardner	Reliability	Electric Intangible Plant	6,443		6,443	790,322	14,900	805,222	480,743	200	480,943				**1,292,608**
Gardner	Reliability	Electric Nuclear Production Plant	64,216,092	1,681,234	65,897,326	86,895,315	1,275,041	88,170,356	96,898,212	3,231,186	100,129,398	59,744,742	767,500	60,512,242	**314,709,321**
Gardner Total			**223,535,843**	**1,938,141**	**225,473,984**	**219,944,591**	**3,929,448**	**223,874,039**	**241,675,513**	**3,255,621**	**244,931,134**	**179,503,082**	**782,500**	**180,285,582**	**874,564,739**
Husen	Fleet, Tools and Communications	Common General Plant	2,080,741	(36,743)	2,043,998	622,539		622,539	2,004,879		2,004,879	707,053		707,053	**5,378,468**
Husen	Fleet, Tools and Communications	Electric General Plant	23,519	(521,655)	(498,136)	1,366,000		1,366,000	162,000		162,000	1,056,000		1,056,000	**2,085,864**
Husen	Fueling Depots	Common General Plant	743,120		743,120	220,000		220,000							**963,120**
Husen	PHEV	Common General Plant	770,000		770,000	693,200		693,200	256,850		256,850	217,900		217,900	**1,937,950**
Husen	PHEV	Electric General Plant	29,500		29,500	272,650		272,650	544,750		544,750	1,516,850		1,516,850	**2,363,750**
Husen	Replacements, Additions, & Repairs	Electric General Plant	19,435,566		19,435,566	28,412,182		28,412,182	31,626,481		31,626,481	28,138,079		28,138,079	**107,612,308**
Husen Total			**23,082,446**	**(558,398)**	**22,524,048**	**31,586,571**		**31,586,571**	**34,594,960**		**34,594,960**	**31,635,882**		**31,635,882**	**120,341,460**

Northern States Power Company
Expenditures and Additions by Witness
Capital Expenditures Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 4
Page 2 of 4

Total Company

Witness	Major category	Functional Class	2021 CWIP spend	2021 RWIP spend	2021 Total	2022 CWIP spend	2022 RWIP spend	2022 Total	2023 CWIP spend	2023 RWIP spend	2023 Total	2024 CWIP spend	2024 RWIP spend	2024 Total	Grand Total
Moeller	Enhance Capabilities	Common General Plant	1,125,410		1,125,410	1,716,876		1,716,876	1,716,876		1,716,876	1,716,876		1,716,876	**6,276,038**
Moeller	Enhance Capabilities	Common Intangible Plant	2,250,000		2,250,000	15,542,000		15,542,000							**17,792,000**
Moeller	Enterprise Security Capital	Common General Plant	71,716	5,992	77,709										**77,709**
Moeller	Enterprise Security Capital	Common Intangible Plant	10,164,312		10,164,312	6,786,756		6,786,756							**16,951,068**
Moeller	Enterprise Security Capital	Electric General Plant	220,680	6,802	227,482										**227,482**
Moeller	Enterprise Security Capital	Electric Hydro Production Plant	34,444	3,827	38,271										**38,271**
Moeller	Fleet, Tools and Communications	Common General Plant	2,109,094		2,109,094	8,562,171		8,562,171	390,000		390,000	390,000		390,000	**11,451,265**
Moeller	Fleet, Tools and Communications	Electric General Plant	337,267		337,267				25,000		25,000				**362,267**
Moeller	Other	Common General Plant	1,017,753	32,326	1,050,080	2,600,000		2,600,000							**3,650,080**
Moeller	Other	Common Intangible Plant	(480,128)		(480,128)										**(480,128)**
Moeller	Other	Electric Distribution Plant	(21,596,599)	18,713	(21,577,886)										**(21,577,886)**
Moeller	Other	Electric General Plant	(33,359)	3,237	(30,121)										**(30,121)**
Moeller	Other	Electric Intangible Plant	33,359		33,359										**33,359**
Moeller	Other	Electric Other Production Plant	22,664,537		22,664,537										**22,664,537**
Moeller	Other	Electric Steam Production Plant	-		-										**-**
Moeller	Other	Electric Transmission Plant	(606,983)	(21,951)	(628,934)										**(628,934)**
Moeller	Property Services Capital	Common General Plant	39,111,268	1,553,761	40,665,029	37,904,483	1,016,604	38,921,087	27,468,743	736,874	28,205,617	4,655,666	143,845	4,799,511	**112,591,244**
Moeller	Property Services Capital	Electric General Plant	10,055,353	201,127	10,256,480	24,801,402	565,363	25,366,765	43,334,628	1,419,324	44,753,952	29,232,138	1,503,010	30,735,148	**111,112,345**
Moeller Total			**66,478,124**	**1,803,836**	**68,281,960**	**97,913,688**	**1,581,967**	**99,495,655**	**72,935,247**	**2,156,198**	**75,091,445**	**35,994,680**	**1,646,855**	**37,641,535**	**280,510,595**
Remington	Aging Technology	Common General Plant	28,511,001		28,511,001	29,217,826		29,217,826	27,668,428		27,668,428	30,287,912		30,287,912	**115,685,167**
Remington	Aging Technology	Common Intangible Plant	24,821,072		24,821,072	26,080,941		26,080,941	39,848,153		39,848,153	9,310,758		9,310,758	**100,060,923**
Remington	Aging Technology	Electric General Plant	9,885,863		9,885,863	16,423,995		16,423,995	9,994,754		9,994,754	2,674,191		2,674,191	**38,978,802**
Remington	Aging Technology	Electric Intangible Plant	8,581,272		8,581,272	8,573,391		8,573,391	2,927,525		2,927,525				**20,082,187**
Remington	AGIS	Common General Plant	295,306		295,306										**295,306**
Remington	AGIS	Electric General Plant	5,433,825		5,433,825	2,586,220		2,586,220				150,000		150,000	**8,170,045**
Remington	AGIS	Electric Intangible Plant	3,008,058		3,008,058	3,448,920		3,448,920	8,152,202		8,152,202	8,224,400		8,224,400	**22,833,580**
Remington	Customer	Common General Plant	4,129,533		4,129,533	9,000		9,000							**4,138,533**
Remington	Customer	Common Intangible Plant	22,330,571		22,330,571	6,365,860		6,365,860	1,218,164		1,218,164	435,059		435,059	**30,349,654**
Remington	Cyber Security	Common General Plant	1,677,847		1,677,847	2,575,000		2,575,000	1,873,301		1,873,301	2,248,301		2,248,301	**8,374,449**
Remington	Cyber Security	Common Intangible Plant	12,302,242		12,302,242	12,073,762		12,073,762	15,206,796		15,206,796	14,756,796		14,756,796	**54,339,596**
Remington	Cyber Security	Electric General Plant	657,606		657,606	235,000		235,000							**892,606**
Remington	Cyber Security	Electric Intangible Plant	517,288		517,288	500,000		500,000							**1,017,288**
Remington	Emergent Demand	Common General Plant	(8,316,570)		(8,316,570)	7,912,324		7,912,324	8,132,583		8,132,583	7,867,036		7,867,036	**15,595,373**
Remington	Emergent Demand	Common Intangible Plant	(5,517,642)		(5,517,642)	1,466,925		1,466,925	(1,607,854)		(1,607,854)	7,205,901		7,205,901	**1,547,329**
Remington	Enhance Capabilities	Common General Plant	9,538,407		9,538,407	6,336,979		6,336,979	1,526,480		1,526,480	750,000		750,000	**18,151,865**
Remington	Enhance Capabilities	Common Intangible Plant	23,468,492		23,468,492	24,901,063		24,901,063	15,256,982		15,256,982	11,558,975		11,558,975	**75,185,512**
Remington	Enhance Capabilities	Electric General Plant	767,134		767,134	1,933,720		1,933,720	350,000		350,000	350,000		350,000	**3,400,854**
Remington	Enhance Capabilities	Electric Intangible Plant	21,527,943		21,527,943	12,813,347		12,813,347	8,505,992		8,505,992	2,349,209		2,349,209	**45,196,492**
Remington Total			**163,619,247**		**163,619,247**	**163,454,273**		**163,454,273**	**139,053,506**		**139,053,506**	**98,168,537**		**98,168,537**	**564,295,563**
Grand Total			**1,743,204,031**	**31,472,123**	**1,774,676,154**	**1,965,845,041**	**58,979,446**	**2,024,824,487**	**1,797,846,892**	**47,179,751**	**1,845,026,644**	**1,747,629,456**	**37,101,670**	**1,784,731,126**	**7,429,258,410**

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

Total Company

Witness	Major category	Functional Class	2021	2022	2023	2024	Grand Total
Benson	Asset Renewal	Electric General Plant	(9,815,515)	(7,106,441)	(8,982,522)	(5,139,306)	**(31,043,784)**
Benson	Asset Renewal	Electric Transmission Plant	(77,982,655)	(145,210,117)	(186,360,412)	(142,575,661)	**(552,128,844)**
Benson	Comm Infrastructure	Electric General Plant	(3,038,869)	(11,203,958)	(23,978,931)	(25,576,441)	**(63,798,199)**
Benson	Comm Infrastructure	Electric Transmission Plant	(4,674,006)	(19,869,765)	(318,500)		**(24,862,272)**
Benson	Interconnection	Electric General Plant	(623,422)				**(623,422)**
Benson	Interconnection	Electric Transmission Plant	(43,233,691)	(5,853,749)	(13,815,950)	(20,907,476)	**(83,810,867)**
Benson	Regional Expansion	Electric General Plant	(122,298)				**(122,298)**
Benson	Regional Expansion	Electric Transmission Plant	(56,059,450)	(4,893,429)		(14,640,702)	**(75,593,582)**
Benson	Reliability Requirement	Electric General Plant	(585,388)	(379,494)			**(964,882)**
Benson	Reliability Requirement	Electric Transmission Plant	(53,142,961)	(12,405,179)	(27,653,013)	(18,388,282)	**(111,589,435)**
Benson	Security\Resiliency	Electric General Plant	(3,047,746)	(13,134,721)	(8,585,593)	(5,791,489)	**(30,559,550)**
Benson	Security\Resiliency	Electric Intangible Plant		(748,253)	(1,028,466)	(1,862,320)	**(3,639,040)**
Benson	Security\Resiliency	Electric Transmission Plant	(20,592,020)	(29,543,620)	(30,490,880)	(9,138,405)	**(89,764,925)**
Benson Total			**(272,918,021)**	**(250,348,728)**	**(301,214,267)**	**(244,020,083)**	**(1,068,501,099)**
Bloch	AGIS	Electric Distribution Plant	(1,062,567)	(86,530,240)	(116,437,075)	(100,385,585)	**(304,415,467)**
Bloch	AGIS	Electric General Plant	(6,730,639)	(1,644,623)	(1,622,959)	(34,454,371)	**(44,452,591)**
Bloch	AGIS	Electric Intangible Plant	(883,875)	(751,418)	(944,702)	(945,064)	**(3,525,059)**
Bloch	Asset Health & Reliability	Electric Distribution Plant	(116,772,804)	(168,756,686)	(180,583,432)	(204,791,070)	**(670,903,992)**
Bloch	Asset Health & Reliability	Electric General Plant	(85,292)	(154,515)	(193,394)	(205,663)	**(638,864)**
Bloch	Capacity	Electric Distribution Plant	(59,706,585)	(33,165,924)	(40,836,235)	(52,954,541)	**(186,663,285)**
Bloch	Capacity	Electric General Plant			(700,000)		**(700,000)**
Bloch	Electric Vehicles	Electric Distribution Plant	(4,925,495)	(79,071,702)	(69,722,962)	(60,484,731)	**(214,204,890)**
Bloch	Fleet, Tools and Communications	Common General Plant	(295,362)	(542,324)	(354,206)	(362,955)	**(1,554,848)**
Bloch	Fleet, Tools and Communications	Common Intangible Plant	(1,085,054)				**(1,085,054)**
Bloch	Fleet, Tools and Communications	Electric Distribution Plant	(1,781,484)	(778,432)	(405,236)	(400,072)	**(3,365,225)**
Bloch	Fleet, Tools and Communications	Electric General Plant	(6,603,150)	(13,091,938)	(15,356,822)	(15,584,166)	**(50,636,076)**
Bloch	Mandates	Electric Distribution Plant	(42,812,996)	(27,999,135)	(29,222,023)	(33,476,186)	**(133,510,342)**
Bloch	New Business	Electric Distribution Plant	(61,390,083)	(60,546,240)	(61,266,682)	(61,465,163)	**(244,668,168)**
Bloch	Solar	Electric Distribution Plant	14,150,947	23,237	1,241	93	**14,175,518**
Bloch	Solar	Electric General Plant	643,825	181,015	12,439	855	**838,134**
Bloch Total			**(289,340,614)**	**(472,828,926)**	**(517,632,048)**	**(565,508,620)**	**(1,845,310,208)**
Capra	Coal	Electric General Plant	(389,686)	(446,000)	(350,000)	(350,000)	**(1,535,686)**
Capra	Coal	Electric Steam Production Plant	(29,027,074)	(12,343,730)	(12,339,799)	(12,562,152)	**(66,272,755)**
Capra	Dispatchable	Electric General Plant	(647,647)	(75,000)	(75,000)	(105,000)	**(902,647)**
Capra	Dispatchable	Electric Other Production Plant	(8,587,889)	(18,650,780)	(20,838,038)	(7,258,251)	**(55,334,959)**
Capra	Dispatchable	Electric Steam Production Plant	(7,434,493)	(12,194,329)	(6,873,856)	(5,028,179)	**(31,530,857)**
Capra	Hydro	Electric General Plant	(7,500)	(15,000)	(15,000)	(15,000)	**(52,500)**
Capra	Hydro	Electric Hydro Production Plant	(81,328)	(25,819)	(74)	(8)	**(107,229)**
Capra	Intermediate	Electric General Plant	(690,985)	(1,344,620)	(570,455)	(636,765)	**(3,242,825)**
Capra	Intermediate	Electric Intangible Plant	(218,018)	(1,339,492)			**(1,557,511)**
Capra	Intermediate	Electric Other Production Plant	(28,569,475)	(35,367,727)	(24,810,120)	(34,148,378)	**(122,895,701)**
Capra	Solar	Electric Other Production Plant			(303,994,870)	(305,794,548)	**(609,789,418)**
Capra	Wind	Electric General Plant	(2,568,349)	(676,506)	(128,493)	(120,000)	**(3,493,349)**
Capra	Wind	Electric Intangible Plant	(51,500)	(596,000)	(8,000)	(203,966)	**(859,466)**
Capra	Wind	Electric Other Production Plant	(1,305,786,744)	(454,806,634)	(120,519,317)	(5,293,468)	**(1,886,406,163)**
Capra	Wind	Electric Transmission Plant	(60,089,208)				**(60,089,208)**
Capra Total			**(1,444,149,897)**	**(537,881,638)**	**(490,523,022)**	**(371,515,716)**	**(2,844,070,274)**
Gardner	Dry Cask Storage	Electric Intangible Plant	(120,160)				**(120,160)**
Gardner	Dry Cask Storage	Electric Nuclear Production Plant	(12,904,361)	(24,789,181)	(16,310,910)		**(54,004,451)**
Gardner	Facilities & Other	Electric General Plant	(572,918)	(100,000)	(700,000)	(100,000)	**(1,472,918)**
Gardner	Facilities & Other	Electric Intangible Plant	(3,220,213)				**(3,220,213)**
Gardner	Facilities & Other	Electric Nuclear Production Plant	(1,989,277)	(658,497)	(870,348)	(204,068)	**(3,722,190)**

			Total Company				
Witness	**Major category**	**Functional Class**	**2021**	**2022**	**2023**	**2024**	**Grand Total**
Gardner	Improvements	Electric General Plant	(9,642,558)	(5,266,248)	(251,682)	(100,000)	**(15,260,488)**
Gardner	Improvements	Electric Intangible Plant	(9,336,357)	(1,026,216)	(8,262,032)		**(18,624,606)**
Gardner	Improvements	Electric Nuclear Production Plant	(1,774,640)	(2,693,587)	(3,468,495)	(5,524,817)	**(13,461,539)**
Gardner	Mandated Compliance	Electric Nuclear Production Plant	(4,923,227)	(1,036,469)	(1,020,054)	(1,020,338)	**(8,000,088)**
Gardner	Nuclear Fuel	Nuclear Fuel	(147,306,554)	(77,578,739)	(158,209,934)	(70,841,762)	**(453,936,990)**
Gardner	Reliability	Electric General Plant	(1,678,073)	(4,755,045)	(1,550,000)	(5,152,671)	**(13,135,790)**
Gardner	Reliability	Electric Intangible Plant			(1,350,452)		**(1,350,452)**
Gardner	Reliability	Electric Nuclear Production Plant	(69,104,308)	(56,433,162)	(125,495,422)	(49,067,159)	**(300,100,052)**
Gardner Total			**(262,572,647)**	**(174,337,144)**	**(317,489,329)**	**(132,010,816)**	**(886,409,935)**
Husen	Fleet, Tools and Communications	Common General Plant	(2,483,247)	(1,189,760)	(1,817,105)	(876,616)	**(6,366,728)**
Husen	Fleet, Tools and Communications	Electric General Plant	(15,722)	(1,158,966)	(359,598)	(919,226)	**(2,453,512)**
Husen	Fueling Depots	Common General Plant	(743,120)	(220,000)			**(963,120)**
Husen	PHEV	Common General Plant	(770,000)	(693,200)	(256,850)	(217,900)	**(1,937,950)**
Husen	PHEV	Electric General Plant	(29,500)	(272,650)	(544,750)	(1,516,850)	**(2,363,750)**
Husen	Replacements, Additions, & Repairs	Electric General Plant	(20,357,357)	(28,809,574)	(31,535,446)	(28,048,131)	**(108,750,508)**
Husen Total			**(24,398,946)**	**(32,344,149)**	**(34,513,750)**	**(31,578,723)**	**(122,835,568)**
Moeller	Enhance Capabilities	Common General Plant		(812)			**(812)**
Moeller	Enhance Capabilities	Common Intangible Plant		(18,424,319)			**(18,424,319)**
Moeller	Enterprise Security Capital	Common General Plant	(303,430)	(266)	(1)		**(303,696)**
Moeller	Enterprise Security Capital	Common Intangible Plant		(17,965,805)			**(17,965,805)**
Moeller	Enterprise Security Capital	Electric General Plant	(1,063,804)	(64,303)			**(1,128,107)**
Moeller	Enterprise Security Capital	Electric Hydro Production Plant	(44,115)				**(44,115)**
Moeller	Fleet, Tools and Communications	Common General Plant	(1,619,741)	(6,324,158)	(2,871,197)	(515,834)	**(11,330,929)**
Moeller	Fleet, Tools and Communications	Electric General Plant	(327,289)	(38,107)	(24,193)	(2,631)	**(392,219)**
Moeller	Other	Common General Plant	(680,306)	(6,691,805)			**(7,372,111)**
Moeller	Property Services Capital	Common General Plant	(20,224,543)	(60,587,478)	(29,315,991)	(4,555,928)	**(114,683,941)**
Moeller	Property Services Capital	Electric General Plant	(5,334,967)	(23,609,571)	(17,900,101)	(14,931,889)	**(61,776,527)**
Moeller Total			**(29,598,193)**	**(133,706,624)**	**(50,111,482)**	**(20,006,282)**	**(233,422,582)**
Remington	Aging Technology	Common General Plant	(32,664,893)	(33,332,519)	(27,973,392)	(29,962,331)	**(123,933,134)**
Remington	Aging Technology	Common Intangible Plant	(37,912,408)	(19,402,280)	(49,800,323)	(11,962,151)	**(119,077,162)**
Remington	Aging Technology	Electric General Plant	(5,016,927)	(2,333,442)	(35,782,308)	(674,191)	**(43,806,867)**
Remington	Aging Technology	Electric Intangible Plant	(10,948,227)	(9,865,474)	(7,642,541)		**(28,456,242)**
Remington	AGIS	Common General Plant	(1,634,660)				**(1,634,660)**
Remington	AGIS	Electric General Plant	(46,409,476)	(7,704,148)		(150,187)	**(54,263,811)**
Remington	AGIS	Electric Intangible Plant	(196,901)	(2,783,888)	(16,251,588)	(7,664,400)	**(26,896,777)**
Remington	Customer	Common General Plant	(4,129,533)	(9,000)			**(4,138,533)**
Remington	Customer	Common Intangible Plant	(36,611,373)	(7,894,925)	(1,218,164)	(435,059)	**(46,159,520)**
Remington	Cyber Security	Common General Plant	(1,526,845)	(2,960,380)	(1,873,301)	(2,248,301)	**(8,608,827)**
Remington	Cyber Security	Common Intangible Plant	(13,541,696)	(13,112,643)	(11,338,533)	(13,335,156)	**(51,328,029)**
Remington	Cyber Security	Electric General Plant	(187,606)	(705,000)			**(892,606)**
Remington	Cyber Security	Electric Intangible Plant	(612,723)	(514,791)			**(1,127,514)**
Remington	Emergent Demand	Common General Plant	1,555,199	1,197,674	(5,441,112)	(7,249,797)	**(9,938,037)**
Remington	Emergent Demand	Common Intangible Plant	2,698,127	1,594,852	1,060,635	(5,523,410)	**(169,797)**
Remington	Enhance Capabilities	Common General Plant	(2,529,008)	(725,000)	(23,811,048)	(250,000)	**(27,315,056)**
Remington	Enhance Capabilities	Common Intangible Plant	(35,504,117)	(21,111,022)	(13,885,546)	(11,878,158)	**(82,378,843)**
Remington	Enhance Capabilities	Electric General Plant	(2,977,483)	(1,683,720)		(200,000)	**(4,861,202)**
Remington	Enhance Capabilities	Electric Intangible Plant	(20,209,231)	(4,745,340)	(18,333,536)	(5,526,144)	**(48,814,250)**
Remington Total			**(248,359,781)**	**(126,091,045)**	**(212,290,757)**	**(97,059,284)**	**(683,800,868)**
Grand Total			**(2,571,338,100)**	**(1,727,538,254)**	**(1,923,774,655)**	**(1,461,699,524)**	**(7,684,350,533)**

Note: This schedule includes only Electric Distribution assets located in the State of Minnesota.

Northern States Power Company
Tie-Out to Rate Base - CWIP
2022-2024

Docket No. E002/GR-21-630
Exhibit ___(MPM-1), Schedule 5
Page 1 of 4

		Schedule 2, Pages 3-4			Schedule 2, Pages 5-6			Schedule 2, Pages 7-8		
		2022			2023			2024		
Line No.	Functional Class	January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average
1	Electric Intangible Plant	$ 30,543,678	$ 46,958,490	$ 38,751,084	$ 46,958,490	$ 27,793,498	$ 37,375,994	$ 27,793,498	$ 34,127,085	$ 30,960,291
2	Electric Steam Production Plant	5,965,038	6,362,066	6,163,552	6,362,066	6,927,548	6,644,807	6,927,548	3,709,834	5,318,691
3	Electric Nuclear Production Plant	54,954,821	91,299,045	73,126,933	91,299,045	76,023,024	83,661,035	76,023,024	111,657,555	93,840,289
4	Nuclear Fuel	101,869,084	117,249,775	109,559,429	117,249,775	69,507,028	93,378,402	69,507,028	86,001,902	77,754,465
5	Electric Hydro Production Plant	245,493	281,403	263,448	281,403	441,072	361,237	441,072	937,076	689,074
6	Electric Other Production Plant	157,000,829	285,176,851	221,088,840	285,176,851	260,816,430	272,996,640	260,816,430	442,680,688	351,748,559
7	Electric Transmission Plant	30,899,364	89,376,143	60,137,753	89,376,143	119,803,284	104,589,713	119,803,284	228,846,412	174,324,848
8	Electric Distribution Plant	48,707,560	85,993,911	67,350,735	85,993,911	79,403,079	82,698,495	79,403,079	74,260,137	76,831,608
9	Electric General Plant	35,524,846	58,494,998	47,009,922	58,494,998	77,214,387	67,854,692	77,214,387	77,270,832	77,242,609
10	***Total Electric Utlity***	**$ 465,710,713**	**$ 781,192,683**	**$ 623,451,698**	**$ 781,192,683**	**$ 717,929,350**	**$ 749,561,016**	**$ 717,929,350**	**$ 1,059,491,520**	**$ 888,710,435**
11	Common Intangible Plant	$ 20,527,593	$ 20,700,736	$ 20,614,165	$ 20,700,736	$ 17,213,553	$ 18,957,144	$ 17,213,553	$ 18,800,161	$ 18,006,857
12	Common General Plant	42,873,232	32,324,545	37,598,889	32,324,545	11,350,384	21,837,465	11,350,384	14,763,013	13,056,699
13	***Total Common Utility***	**$ 63,400,825**	**$ 53,025,281**	**$ 58,213,053**	**$ 53,025,281**	**$ 28,563,937**	**$ 40,794,609**	**$ 28,563,937**	**$ 33,563,174**	**$ 31,063,556**
14	***Total Electric and Common Utility***	**$ 529,111,538**	**$ 834,217,964**	**$ 681,664,751**	**$ 834,217,964**	**$ 746,493,287**	**$ 790,355,625**	**$ 746,493,287**	**$ 1,093,054,694**	**$ 919,773,991**

Line No.	Functional Class	2022 BOY/EOY Average (In Thousands)	Reconciling Items	Unadjusted Test Year Halama Direct Schedule 9 Page 1	2023 BOY/EOY Average (In Thousands)	Reconciling Items	Plan Year Unadjusted Plant Rate Base Schedules - B-2 (Note 1)	2024 BOY/EOY Average (In Thousands)	Reconciling Items	Plan Year Unadjusted Plant Rate Base Schedules - B-2 (Note 1)
15	Subtotal Electric Production Plant	$ 410,202			$ 457,042			$ 529,351		
16	*Include Pre-funded AFUDC*		(2,914)			(5,262)			(7,033)	
17	Total Electric Production Plant	$ 410,202	$ (2,914)	$ 407,288	$ 457,042	$ (5,262)	$ 451,780	$ 529,351	$ (7,033)	$ 522,318
18	Subtotal Electric Transmission Plant	$ 60,138			$ 104,590			$ 174,325		
19	*Include Pre-funded AFUDC*		(681)			(839)			(1,237)	
20	Total Electric Transmission Plant	$ 60,138	$ (681)	$ 59,456	$ 104,590	$ (839)	$ 103,751	$ 174,325	$ (1,237)	$ 173,088
21	Total Electric Distribution Plant	$ 67,351	$ -	$ 67,351	$ 82,698	$ -	$ 82,698	$ 76,832	$ -	$ 76,832
22	Total Electric General Plant	$ 85,761	$ -	$ 85,761	$ 105,231	$ -	$ 105,231	$ 108,203	$ -	$ 108,203
23	Subtotal Common Plant	$ 58,213			$ 40,795			$ 31,064		
24	*Remove Common Allocated to Gas Utility*		(4,449)			(3,258)			(2,604)	
25	Total Common Plant	$ 58,213	$ (4,449)	$ 53,764	$ 40,795	$ (3,258)	$ 37,537	$ 31,064	$ (2,604)	$ 28,460
26	***Total CWIP***	**$ 681,665**	**$ (8,045)**	**$ 673,620**	**$ 790,356**	**$ (9,359)**	**$ 780,997**	**$ 919,774**	**$ (10,874)**	**$ 908,900**

Note 1 - Found at: Volume 3, II Required Financial Information, 3. Rate Base Schedules, B. Detailed Rate Base Components, Schedule B-2

Northern States Power Company
Tie-Out to Rate Base - Plant In-Service
2022-2024

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 5
Page 2 of 4

Line No.	Functional Class	Schedule 2, Pages 11-12			Schedule 2, Pages 13-14			Schedule 2, Pages 15-16		
		2022			2023			2024		
		January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average
1	Electric Intangible Plant	$ 446,681,279	$ 469,052,150	$ 457,866,714	$ 469,052,150	$ 522,873,467	$ 495,962,808	$ 522,873,467	$ 539,075,361	$ 530,974,414
2	Electric Steam Production Plant	2,377,538,182	2,174,164,852	2,275,851,517	2,174,164,852	2,193,378,507	2,183,771,680	2,193,378,507	2,210,968,838	2,202,173,673
3	Electric Nuclear Production Plant	4,031,276,577	4,116,887,473	4,074,082,025	4,116,887,473	4,264,052,702	4,190,470,087	4,264,052,702	4,319,869,084	4,291,960,893
4	Nuclear Fuel	2,981,177,798	3,058,756,537	3,019,967,167	3,058,756,537	3,216,966,471	3,137,861,504	3,216,966,471	3,287,808,233	3,252,387,352
5	Electric Hydro Production Plant	28,007,730	28,033,549	28,020,640	28,033,549	28,033,623	28,033,586	28,033,623	28,033,631	28,033,627
6	Electric Other Production Plant	5,465,107,695	5,511,079,799	5,488,093,747	5,511,079,799	5,767,090,070	5,639,084,935	5,767,090,070	6,119,584,716	5,943,337,393
7	Electric Transmission Plant	4,221,890,099	4,426,354,157	4,324,122,128	4,426,354,157	4,670,982,440	4,548,668,298	4,670,982,440	4,861,775,702	4,766,379,071
8	Electric Distribution Plant	4,808,914,949	5,274,746,894	5,041,830,922	5,274,746,894	5,808,735,826	5,541,741,360	5,808,735,826	6,312,591,976	6,060,663,901
9	Electric General Plant	775,405,029	900,997,604	838,201,317	900,997,604	1,050,192,411	975,595,008	1,050,192,411	1,189,965,533	1,120,078,972
10	***Total Electric Utility***	**$ 25,135,999,338**	**$ 25,960,073,017**	**$ 25,548,036,177**	**$ 25,960,073,017**	**$ 27,522,305,517**	**$ 26,741,189,267**	**$ 27,522,305,517**	**$ 28,869,673,074**	**$ 28,195,989,296**
11	Common Intangible Plant	$ 635,549,985	$ 731,866,128	$ 683,708,057	$ 731,866,128	$ 807,048,060	$ 769,457,094	$ 807,048,060	$ 850,181,994	$ 828,615,027
12	Common General Plant	479,779,013	591,858,041	535,818,527	591,858,041	685,572,245	638,715,143	685,572,245	731,811,906	708,692,075
13	***Total Common Utility***	**$ 1,115,328,998**	**$ 1,323,724,169**	**$ 1,219,526,584**	**$ 1,323,724,169**	**$ 1,492,620,304**	**$ 1,408,172,237**	**$ 1,492,620,304**	**$ 1,581,993,900**	**$ 1,537,307,102**
14	***Total Electric and Common Utility***	**$ 26,251,328,337**	**$ 27,283,797,186**	**$ 26,767,562,761**	**$ 27,283,797,186**	**$ 29,014,925,821**	**$ 28,149,361,504**	**$ 29,014,925,821**	**$ 30,451,666,974**	**$ 29,733,296,398**

Line No.	Functional Class	2022 BOY/EOY Average (In Thousands)	Reconciling Items	Test Year Unadjusted Plant Halama Direct Schedule 9, Page 1	2023 BOY/EOY Average (In Thousands)	Reconciling Items	Plan Year Unadjusted Plant Rate Base Schedules - B-2 (Note 1)	2024 BOY/EOY Average (In Thousands)	Reconciling Items	Plan Year Unadjusted Plant Rate Base Schedules - B-2 (Note 1)
15	Subtotal Electric Production Plant	$ 14,886,015			$ 15,179,222			$ 15,717,893		
16	*Include Pre-funded AFUDC*		(193,613)			(206,726)			(218,816)	
17	Total Electric Production Plant	$ 14,886,015	$ (193,613)	$ 14,692,403	$ 15,179,222	$ (206,726)	$ 14,972,496	$ 15,717,893	$ (218,816)	$ 15,499,076
18	Subtotal Electric Transmission Plant	$ 4,324,122			$ 4,548,668			$ 4,766,379		
19	*Include Pre-funded AFUDC*		(93,437)			(93,979)			(94,508)	
20	Total Electric Transmission Plant	$ 4,324,122	$ (93,437)	$ 4,230,685	$ 4,548,668	$ (93,979)	$ 4,454,690	$ 4,766,379	$ (94,508)	$ 4,671,872
21	Subtotal Electric Distribution Plant	$ 5,041,831			$ 5,541,741			$ 6,060,664		
22	*Include New Business CIAC*		(1,400)			(1,400)			(1,400)	
23	Total Electric Distribution Plant	$ 5,041,831	$ (1,400)	$ 5,040,431	$ 5,541,741	$ (1,400)	$ 5,540,341	$ 6,060,664	$ (1,400)	$ 6,059,264
24	Subtotal Electric General Plant	$ 1,296,068			$ 1,471,558			$ 1,651,053		
25	Total Electric General Plant	$ 1,296,068	$ -	$ 1,296,068	$ 1,471,558	$ -	$ 1,471,558	$ 1,651,053	$ -	$ 1,651,053
26	Subtotal Common Plant	$ 1,219,527			$ 1,408,172			$ 1,537,307		
27	*Remove Common Allocated to Gas Utility*		(102,729)			(117,818)			(128,166)	
28	Total Common Plant	$ 1,219,527	$ (102,729)	$ 1,116,798	$ 1,408,172	$ (117,818)	$ 1,290,354	$ 1,537,307	$ (128,166)	$ 1,409,141
29	***Total Plant In-Service***	**$ 26,767,563**	**$ (391,178)**	**$ 26,376,384**	**$ 28,149,362**	**$ (419,923)**	**$ 27,729,439**	**$ 29,733,296**	**$ (442,890)**	**$ 29,290,406**

Note 1 - Found at: Volume 3, II Required Financial Information, 3. Rate Base Schedules, B. Detailed Rate Base Components, Schedule B-2

Northern States Power Company
Tie-Out to Rate Base Depreciation Reserve
2022-2024

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 5
Page 3 of 4

		Schedule 2, Pages 21-24			Schedule 2, Pages 25-28			Schedule 2, Pages 29-32		
		2022			2023			2024		
Line No.	Functional Class	January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average
1	*Electric Intangible Plant*	$ 249,855,447	$ 282,342,574	$ 266,099,011	$ 282,342,574	$ 316,128,463	$ 299,235,519	$ 316,128,463	$ 352,877,527	$ 334,502,995
2	*Electric Intangible Plant RWIP*	-	(14,900)	(7,450)	(14,900)	-	(7,450)	-	-	-
3	*Total Electric Intangible Including RWIP*	**249,855,447**	**282,327,674**	**266,091,561**	**282,327,674**	**316,128,463**	**299,228,069**	**316,128,463**	**352,877,527**	**334,502,995**
4	*Electric Steam Production Plant*	1,753,836,184	1,634,026,814	1,693,931,499	1,634,026,814	1,720,495,820	1,677,261,317	1,720,495,820	1,821,039,810	1,770,767,815
5	*Electric Steam Production Plant RWIP*	(1,893,334)	(9,756,349)	(5,824,842)	(9,756,349)	(1,896,494)	(5,826,421)	(1,896,494)	(6,764,758)	(4,330,626)
6	*Total Electric Steam Production Including RWIP*	**1,751,942,850**	**1,624,270,465**	**1,688,106,658**	**1,624,270,465**	**1,718,599,326**	**1,671,434,896**	**1,718,599,326**	**1,814,275,052**	**1,766,437,189**
7	*Electric Nuclear Production Plant*	2,231,799,155	2,400,072,531	2,315,935,843	2,400,072,531	2,581,086,985	2,490,579,758	2,581,086,985	2,775,873,726	2,678,480,356
8	*Electric Nuclear Production Plant RWIP*	(1,661,606)	(1,140,583)	(1,401,095)	(1,140,583)	(209,643)	(675,113)	(209,643)	(230,104)	(219,874)
9	*Total Electric Nuclear Production Including RWIP*	**2,230,137,549**	**2,398,931,949**	**2,314,534,749**	**2,398,931,949**	**2,580,877,342**	**2,489,904,646**	**2,580,877,342**	**2,775,643,622**	**2,678,260,482**
10	*Nuclear Fuel*	2,772,531,416	2,892,031,275	2,832,281,346	2,892,031,275	3,008,259,761	2,950,145,518	3,008,259,761	3,128,137,204	3,068,198,483
11	*Nuclear Fuel RWIP*	-	-	-	-	-	-	-	-	-
12	*Total Nuclear Fuel Including RWIP*	**2,772,531,416**	**2,892,031,275**	**2,832,281,346**	**2,892,031,275**	**3,008,259,761**	**2,950,145,518**	**3,008,259,761**	**3,128,137,204**	**3,068,198,483**
13	*Electric Hydro Production Plant*	17,610,750	19,083,032	18,346,891	19,083,032	20,557,503	19,820,267	20,557,503	22,031,985	21,294,744
14	*Electric Hydro Production Plant RWIP*	(1,372)	(1,318)	(1,345)	(1,318)	(1,313)	(1,315)	(1,313)	(1,312)	(1,312)
15	*Total Hydro Production Including RWIP*	**17,609,379**	**19,081,713**	**18,345,546**	**19,081,713**	**20,556,190**	**19,818,952**	**20,556,190**	**22,030,673**	**21,293,432**
16	*Electric Other Production Plant*	1,367,759,531	1,119,741,685	1,243,750,608	1,119,741,685	1,137,663,249	1,128,702,467	1,137,663,249	1,346,279,238	1,241,971,243
17	*Electric Other Production Plant RWIP*	(20,563,337)	(33,830,701)	(27,197,019)	(33,830,701)	(45,529,572)	(39,680,136)	(45,529,572)	(9,531,820)	(27,530,696)
18	*Total Electric Other Production Including RWIP*	**1,347,196,195**	**1,085,910,984**	**1,216,553,589**	**1,085,910,984**	**1,092,133,677**	**1,089,022,330**	**1,092,133,677**	**1,336,747,417**	**1,214,440,547**
19	*Electric Transmission Plant*	1,080,943,236	1,143,636,209	1,112,289,723	1,143,636,209	1,215,849,493	1,179,742,851	1,215,849,493	1,293,586,953	1,254,718,223
20	*Electric Transmission Plant RWIP*	(8,875,702)	(3,253,938)	(6,064,820)	(3,253,938)	(2,189,806)	(2,721,872)	(2,189,806)	(3,165,621)	(2,677,713)
21	*Total Electric Transmission Including RWIP*	**1,072,067,534**	**1,140,382,272**	**1,106,224,903**	**1,140,382,272**	**1,213,659,687**	**1,177,020,979**	**1,213,659,687**	**1,290,421,332**	**1,252,040,509**
22	*Electric Transmission - Theoretical Reserve*	(131,894,499)	(128,353,919)	(130,124,209)	(128,353,919)	(124,813,339)	(126,583,629)	(124,813,339)	(121,272,759)	(123,043,049)
23	*Electric Transmission - Theoretical Reserve RWIP*	-	-	-	-	-	-	-	-	-
24	*Electric Transmission - Theoretical Reserve Including RWIP*	**(131,894,499)**	**(128,353,919)**	**(130,124,209)**	**(128,353,919)**	**(124,813,339)**	**(126,583,629)**	**(124,813,339)**	**(121,272,759)**	**(123,043,049)**
25	*Electric Distribution Plant*	1,804,611,935	1,889,479,003	1,847,045,469	1,889,479,003	1,992,951,032	1,941,215,017	1,992,951,032	2,119,552,706	2,056,251,869
26	*Electric Distribution Plant RWIP*	(5,158,155)	(6,039,157)	(5,598,656)	(6,039,157)	(5,561,574)	(5,800,365)	(5,561,574)	(6,581,714)	(6,071,644)
27	*Total Electric Distribution Including RWIP*	**1,799,453,780**	**1,883,439,846**	**1,841,446,813**	**1,883,439,846**	**1,987,389,458**	**1,935,414,652**	**1,987,389,458**	**2,112,970,992**	**2,050,180,225**
28	*Electric Distribution - Theoretical Reserve*	(81,287,811)	(76,543,268)	(78,915,539)	(76,543,268)	(71,910,495)	(74,226,882)	(71,910,495)	(67,277,722)	(69,594,109)
29	*Electric Distribution - Theoretical Reserve RWIP*	-	-	-	-	-	-	-	-	-
30	*Electric Distribution - Theoretical Reserve Including RWIP*	**(81,287,811)**	**(76,543,268)**	**(78,915,539)**	**(76,543,268)**	**(71,910,495)**	**(74,226,882)**	**(71,910,495)**	**(67,277,722)**	**(69,594,109)**
31	*Electric General Plant*	356,012,606	411,167,553	383,590,079	411,167,553	473,466,649	442,317,101	473,466,649	544,331,248	508,898,949
32	*Electric General Plant RWIP*	(756,916)	(864,416)	(810,666)	(864,416)	(1,955,539)	(1,409,978)	(1,955,539)	(3,394,578)	(2,675,059)
33	*Total Electric General Including RWIP*	**355,255,690**	**410,303,137**	**382,779,413**	**410,303,137**	**471,511,110**	**440,907,123**	**471,511,110**	**540,936,670**	**506,223,890**
34	*General and Intangible - Theoretical Reserve*	(1,024,369)	(851,530)	(937,950)	(851,530)	(747,441)	(799,486)	(747,441)	(659,293)	(703,367)
35	*General and Intangible - Theoretical Reserve RWIP*	-	-	-	-	-	-	-	-	-
36	*General and Intangible - Theoretical Reserve Including RWIP*	**(1,024,369)**	**(851,530)**	**(937,950)**	**(851,530)**	**(747,441)**	**(799,486)**	**(747,441)**	**(659,293)**	**(703,367)**
37	*Total Electric Utility*	**11,420,753,583**	**11,585,831,959**	**11,503,292,771**	**11,585,831,959**	**12,268,987,679**	**11,927,409,819**	**12,268,987,679**	**13,214,500,624**	**12,741,744,151**
38	*Total Electric Utility RWIP*	**(38,910,422)**	**(54,901,361)**	**(46,905,892)**	**(54,901,361)**	**(57,343,940)**	**(56,122,651)**	**(57,343,940)**	**(29,669,907)**	**(43,506,924)**
39	*Total Electric Utility Including RWIP*	**$ 11,381,843,161**	**$ 11,530,930,598**	**$ 11,456,386,879**	**$ 11,530,930,598**	**$ 12,211,643,739**	**$ 11,871,287,168**	**$ 12,211,643,739**	**$ 13,184,830,717**	**$ 12,698,237,228**

Northern States Power Company
Tie-Out to Rate Base Depreciation Reserve
2022-2024

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 5
Page 4 of 4

Line No.	Functional Class	Schedule 2, Pages 21-24			Schedule 2, Pages 25-28			Schedule 2, Pages 29-32		
		2022			2023			2024		
		January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average	January Beginning Balance	December Ending Balance	BOY/EOY Average
40	*Common Intangible Plant*	$ 333,939,964	$ 399,016,210	$ 366,478,087	$ 399,016,210	$ 476,244,560	$ 437,630,385	$ 476,244,560	557,422,484	$ 516,833,522
41	*Common Intangible Plant RWIP*	-	-	-	-	-	-	-	-	-
42	*Total Common Intangible Including RWIP*	333,939,964	399,016,210	366,478,087	399,016,210	476,244,560	437,630,385	476,244,560	557,422,484	516,833,522
43	*Common General Plant*	156,056,357	198,826,805	177,441,581	198,826,805	247,662,893	223,244,849	247,662,893	303,200,150	275,431,522
44	*Common General Plant RWIP*	(1,806,172)	(1,320,222)	(1,563,197)	(1,320,222)	(733,270)	(1,026,746)	(733,270)	(95,174)	(414,222)
45	*Total Common General Including RWIP*	154,250,184	197,506,583	175,878,384	197,506,583	246,929,623	222,218,103	246,929,623	303,104,976	275,017,300
46	*Total Common Utility*	489,996,320	597,843,015	543,919,668	597,843,015	723,907,453	660,875,234	723,907,453	860,622,634	792,265,043
47	*Total Common Utility RWIP*	(1,806,172)	(1,320,222)	(1,563,197)	(1,320,222)	(733,270)	(1,026,746)	(733,270)	(95,174)	(414,222)
48	*Total Common Utility Including RWIP*	488,190,148	596,522,793	542,356,471	596,522,793	723,174,183	659,848,488	723,174,183	860,527,460	791,850,821
49	*Total Electric and Common Utility*	11,910,749,903	12,183,674,974	12,047,212,438	12,183,674,974	12,992,895,132	12,588,285,053	12,992,895,132	14,075,123,258	13,534,009,195
50	*Total Electric and Common Utility RWIP*	(40,716,594)	(56,221,583)	(48,469,089)	(56,221,583)	(58,077,210)	(57,149,397)	(58,077,210)	(29,765,081)	(43,921,146)
51	*Total Electric and Common Utility Including RWIP*	$ 11,870,033,309	$ 12,127,453,391	$ 11,998,743,350	$ 12,127,453,391	$ 12,934,817,922	$ 12,531,135,656	$ 12,934,817,922	$ 14,045,358,177	$ 13,490,088,049

Line No.	Functional Class	2022 BOY/EOY Average (In Thousands)	Reconciling Items	Test Year Unadjusted Reserve Halama Direct Schedule 9, Page 1	2023 BOY/EOY Average (In Thousands)	Reconciling Items	Plan Year Unadjusted Reserve Rate Base Schedules - B-2 (Note 1)	2024 BOY/EOY Average (In Thousands)	Reconciling Items	Plan Year Unadjusted Reserve Rate Base Schedules - B-2 (Note 1)
1	Subtotal Electric Production Plant	$ 8,069,822			$ 8,220,326			$ 8,748,630		
2	*Include Pre-funded AFUDC*		(54,365)			(60,967)			(67,836)	
3	Total Electric Production Plant	$ 8,069,822	$ (54,365)	$ 8,015,457	$ 8,220,326	$ (60,967)	$ 8,159,359	$ 8,748,630	$ (67,836)	$ 8,680,794
4	Subtotal Electric Transmission Plant	$ 976,101			$ 1,050,437			$ 1,128,997		
5	*Include Pre-funded AFUDC*		(13,270)			(15,275)			(17,364)	
6	Total Electric Transmission Plant	$ 976,101	$ (13,270)	$ 962,831	$ 1,050,437	$ (15,275)	$ 1,035,163	$ 1,128,997	$ (17,364)	$ 1,111,634
7	Subtotal Electric Distribution Plant	$ 1,762,531			$ 1,861,188			$ 1,980,586		
8	*Include New Business CIAC*		(751)			(796)			(842)	
9	Total Electric Distribution Plant	$ 1,762,531	$ (751)	$ 1,761,781	$ 1,861,188	$ (796)	$ 1,860,392	$ 1,980,586	$ (842)	$ 1,979,744
10	Subtotal Electric General Plant	$ 647,933			$ 739,336			$ 840,024		
11	Total Electric General Plant	$ 647,933	$ -	$ 647,933	$ 739,336	$ -	$ 739,336	$ 840,024	$ -	$ 840,024
12	Subtotal Common Plant	$ 542,356			$ 659,848			$ 791,851		
13	*Remove Common Allocated to Gas Utility*		(47,949)			(57,947)			(69,145)	
14	Total Common Plant	$ 542,356	$ (47,949)	$ 494,408	$ 659,848	$ (57,947)	$ 601,901	$ 791,851	$ (69,145)	$ 722,706
15	***Total Depreciation Reserve***	**$ 11,998,743**	**$ (116,335)**	**$ 11,882,409**	**$ 12,531,136**	**$ (134,985)**	**$ 12,396,150**	**$ 13,490,088**	**$ (155,187)**	**$ 13,334,901**

Note 1 - Found at: Volume 3, II Required Financial Information, 3. Rate Base Schedules, B. Detailed Rate Base Components, Schedule B-2

	2021				2022				2023				2024			
	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference
Steam	2,363,514,270	102,090,225	103,341,267	1,251,042	2,160,140,940	109,904,784	111,126,875	1,222,092	2,179,354,595	94,193,730	95,405,173	1,211,443	2,196,944,926	99,425,649	100,623,438	1,197,789
Nuclear	4,029,518,865	164,596,903	164,596,903	-	4,115,129,761	172,686,869	172,686,869	-	4,262,294,990	185,215,338	185,215,338	-	4,318,111,372	195,553,303	195,553,303	-
Hydro	26,314,654	1,460,476	1,489,881	29,406	26,340,473	1,471,614	1,501,042	29,428	26,340,547	1,473,756	1,503,189	29,433	26,340,555	1,473,762	1,503,195	29,433
Other	5,448,932,887	191,159,546	195,048,307	3,888,760	5,271,335,455	220,073,918	223,088,100	3,014,182	5,221,924,877	243,161,209	245,271,434	2,110,226	5,268,624,975	257,007,873	258,921,190	1,913,317
TOTAL	**11,868,280,676**	**459,307,150**	**464,476,358**	**5,169,208**	**11,572,946,628**	**504,137,184**	**508,402,886**	**4,265,702**	**11,689,915,009**	**524,044,032**	**527,395,133**	**3,351,101**	**11,810,021,828**	**553,460,588**	**556,601,126**	**3,140,539**

	2021				2022				2023				2024			
	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference	Ending Plant Balance	Original Depreciation Expense	Revised Depreciation Expense	Difference
Steam																
Allen S King	711,068,573	26,196,175	26,641,929	445,755	713,613,191	26,413,349	26,860,907	447,558	716,084,510	26,621,347	27,070,726	449,380	723,763,487	26,966,019	27,418,940	452,920
Red Wing	70,757,962	3,661,941	3,232,156	(429,785)	77,645,847	5,222,327	4,746,289	(476,038)	79,633,461	6,360,894	5,857,318	(503,577)	80,313,612	6,665,820	6,153,198	(512,622)
Sherco 1	500,205,694	30,279,621	30,210,744	(68,877)	503,062,058	31,985,521	31,915,329	(70,192)	506,193,084	33,229,843	33,158,656	(71,187)	510,049,464	35,545,773	35,472,762	(73,011)
Sherco 2	226,731,584	18,822,461	18,809,833	(12,627)	(0)	20,717,969	20,703,938	(14,030)	107,004	-	-	-	114,690	-	-	-
Sherco 2 - FERC 311	336,834	20,466	20,399	(67)	336,834	20,465	20,398	(67)	336,834	20,453	20,386	(67)	336,834	20,423	20,356	(67)
Sherco 3	789,493,633	20,103,655	21,511,494	1,407,839	795,256,577	21,592,425	23,024,656	1,432,231	801,887,027	22,271,731	23,718,581	1,446,850	802,906,135	22,616,925	24,071,564	1,454,639
Wilmarth	64,919,989	3,005,907	2,914,712	(91,195)	70,226,433	3,952,727	3,855,358	(97,369)	75,112,675	5,689,462	5,579,506	(109,956)	79,460,703	7,610,689	7,486,619	(124,070)
Total Steam	**2,363,514,270**	**102,090,225**	**103,341,267**	**1,251,042**	**2,160,140,940**	**109,904,784**	**111,126,875**	**1,222,092**	**2,179,354,595**	**94,193,730**	**95,405,173**	**1,211,443**	**2,196,944,926**	**99,425,649**	**100,623,438**	**1,197,789**
Nuclear																
Monticello	1,673,647,128	80,352,170	80,352,170	-	1,694,400,471	83,982,204	83,982,204	-	1,742,069,585	88,990,971	88,990,971	-	1,751,370,898	92,741,967	92,741,967	-
Prairie Island	2,355,871,738	84,244,733	84,244,733	-	2,420,729,290	88,704,665	88,704,665	-	2,520,225,404	96,224,366	96,224,366	-	2,566,740,474	102,811,336	102,811,336	-
Total Nuclear	**4,029,518,865**	**164,596,903**	**164,596,903**	**-**	**4,115,129,761**	**172,686,869**	**172,686,869**	**-**	**4,262,294,990**	**185,215,338**	**185,215,338**	**-**	**4,318,111,372**	**195,553,303**	**195,553,303**	**-**
Hydro																
Hennepin Island	19,565,932	1,121,586	1,126,026	4,439	19,591,750	1,132,725	1,137,186	4,461	19,591,824	1,134,866	1,139,333	4,466	19,591,832	1,134,873	1,139,339	4,466
Upper Dam	4,514,522	106,781	107,809	1,029	4,514,522	106,781	107,809	1,029	4,514,522	106,781	107,809	1,029	4,514,522	106,781	107,809	1,029
St Croix Falls	2,234,201	232,109	256,047	23,938	2,234,201	232,109	256,047	23,938	2,234,201	232,109	256,047	23,938	2,234,201	232,109	256,046	23,938
Total Hydro	**26,314,654**	**1,460,476**	**1,489,881**	**29,406**	**26,340,473**	**1,471,614**	**1,501,042**	**29,428**	**26,340,547**	**1,473,756**	**1,503,189**	**29,433**	**26,340,555**	**1,473,762**	**1,503,195**	**29,433**
Other																
Angus Anson Unit 2 & 3	87,153,399	1,329,857	1,398,878	69,021	89,782,539	1,498,338	1,569,251	70,913	101,038,722	2,073,433	2,152,382	78,949	102,282,979	2,335,924	2,418,459	82,536
Angus Anson Unit 2 & 3 - FERC 341	7,614,500	103,796	103,796	-	7,614,500	103,796	103,796	-	7,614,500	103,796	103,796	-	7,614,500	103,796	103,796	-
Angus Anson Unit 4	38,839,680	953,494	953,494	-	47,001,268	1,143,297	1,143,297	-	47,565,807	1,360,798	1,360,798	-	47,565,807	1,382,987	1,382,987	-
Black Dog Unit 5	198,989,585	10,287,897	9,539,767	(748,130)	223,186,266	11,275,058	10,490,898	(784,161)	226,267,196	13,778,645	12,903,133	(875,512)	239,715,017	16,431,141	15,523,687	(907,453)
Black Dog Unit 5 FERC 341	43,238,548	555,741	542,971	(12,769)	43,238,548	555,748	542,980	(12,768)	43,238,548	555,746	542,978	(12,768)	43,238,548	555,744	542,975	(12,768)
Black Dog Unit 6	102,682,165	2,459,431	2,605,208	145,776	102,878,893	2,467,866	2,614,032	146,166	102,878,893	2,472,571	2,618,972	146,401	102,878,893	2,472,571	2,618,972	146,401
Blazing Star I WF	308,190,681	13,313,081	13,704,465	391,384	308,190,681	13,358,571	13,751,250	392,680	308,190,681	13,358,570	13,751,250	392,680	308,190,681	13,358,570	13,751,250	392,680
Blazing Star II WF	338,745,018	14,202,218	14,202,218	-	338,745,018	14,953,745	14,953,745	-	338,745,018	14,953,745	14,953,745	-	338,745,018	14,953,745	14,953,745	-
Blue Lake Units 1 thru 4	24,658,386	199,662	958,981	759,319	24,658,386	205,783	965,368	759,585	(0)	102,729	482,521	379,792	(0)	-	-	-
Blue Lake Units 1 thru 4 - FERC 341	1,153,723	8,199	8,671	473	1,153,723	8,199	8,671	473	1,153,723	8,199	8,671	473	1,153,723	8,199	8,671	473
Blue Lake Units 7 & 8	76,679,218	1,883,366	1,913,277	29,911	81,577,739	2,205,684	2,238,323	32,639	87,618,707	2,377,726	2,411,871	34,145	93,366,793	2,685,489	2,722,252	36,763
Border Winds Project	265,256,170	11,546,400	11,678,752	132,352	266,354,430	11,600,040	11,732,874	132,834	266,354,430	11,644,378	11,777,620	133,242	266,354,430	11,644,378	11,777,620	133,242
Community WF	65,149,231	2,841,885	2,841,885	-	65,149,231	2,852,347	2,852,347	-	65,149,231	2,852,347	2,852,347	-	65,149,231	2,852,347	2,852,347	-
Community Wind Rights	-	(1)	(1)	-	-	(1)	(1)	-	-	(1)	(1)	-	-	(1)	(1)	-
Courtenay WF	282,314,631	12,207,028	12,462,181	255,153	283,098,396	12,295,354	12,551,976	256,622	284,421,922	12,361,560	12,619,231	257,671	285,831,292	12,454,753	12,713,865	259,111
Courtenay Wind Rights	2,085,661	83,285	83,285	-	2,085,661	83,285	83,285	-	2,085,661	83,285	83,285	-	2,085,661	83,285	83,285	-
Crowned Ridge WF	310,133,834	13,564,994	13,564,994	-	312,533,834	13,844,959	13,844,959	-	312,533,834	13,849,600	13,849,600	-	312,533,834	13,849,600	13,849,600	-
Dakota Range WF	394,985,740	725,015	725,015	-	388,122,960	17,188,588	17,188,588	-	388,122,960	17,123,543	17,123,543	-	388,122,960	17,123,543	17,123,543	-
Foxtail WF	239,158,778	10,341,402	10,401,121	59,719	239,158,778	10,355,615	10,415,408	59,793	239,158,778	10,355,615	10,415,408	59,793	239,158,778	10,355,615	10,415,408	59,793
Foxtail Wind Rights	177,364	7,187	7,187	-	177,364	7,149	7,149	-	177,364	7,149	7,149	-	177,364	7,149	7,149	-
Freeborn WF	327,286,848	8,916,639	8,916,639	-	327,286,848	14,447,105	14,447,105	-	327,286,848	14,447,105	14,447,105	-	327,286,848	14,447,105	14,447,105	-
Fuel Holders (Wind-to-Battery)	4,128,902	295,369	886,107	590,738	4,128,902	295,369	-	(295,369)	4,128,902	295,369	-	(295,369)	4,128,902	-	-	-
Grand Meadow WF	202,862,391	9,386,610	9,604,606	217,996	203,693,209	9,606,556	9,826,894	220,338	127,245,806	11,066,871	11,285,608	218,737	129,394,489	20,276,091	20,391,906	115,815
Grand Meadow Wind Rights	10,672,452	478,504	478,504	-	10,672,452	478,504	478,504	-	10,672,452	478,504	478,504	-	10,672,452	478,504	478,504	-
High Bridge	409,984,059	11,546,429	11,665,596	119,167	413,195,026	11,695,481	11,815,424	119,943	432,977,985	12,329,409	12,454,055	124,646	445,993,081	12,939,581	13,068,691	129,110
Inver Hills	58,669,635	2,084,997	2,193,107	108,110	61,631,167	2,548,750	2,659,745	110,995	64,607,515	3,571,300	3,691,615	120,315	64,873,424	3,983,450	4,107,462	124,012
Jeffers WF	69,978,427	3,018,814	3,018,814	-	69,978,427	3,033,233	3,033,233	-	69,978,427	3,033,233	3,033,233	-	69,978,427	3,033,233	3,033,233	-
Jeffers Wind Rights	-	(8)	(8)	-	-	(8)	(8)	-	-	(8)	(8)	-	-	(8)	(8)	-
Lake Benton WF	161,290,643	6,947,408	7,101,481	154,072	161,290,643	6,998,453	7,153,607	155,154	161,290,643	6,998,453	7,153,607	155,154	161,290,643	6,998,453	7,153,607	155,154
Lake Benton Wind Rights	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mower WF	223,361,602	5,779,324	5,779,324	-	223,361,602	7,315,367	7,315,367	-	223,361,602	7,315,367	7,315,367	-	223,361,602	7,315,367	7,315,367	-
Mower Wind Rights	626,931	19,816	19,816	-	626,931	25,036	25,036	-	626,931	25,036	25,036	-	626,931	25,036	25,036	-
Nobles WF	516,310,974	22,199,645	23,063,303	863,658	284,611,671	23,095,369	23,979,687	884,318	288,053,400	39,268,928	39,689,432	420,504	288,453,267	39,737,420	40,160,094	422,674
Nobles Wind Rights	3,884,834	156,495	156,495	-	3,884,834	156,495	156,495	-	3,884,834	156,495	156,495	-	3,884,834	156,495	156,495	-
Pleasant Valley WF	332,998,296	14,380,581	14,912,301	531,721	334,831,596	14,461,878	14,995,776	533,897	336,113,394	14,563,802	15,100,532	536,730	337,448,942	14,651,714	15,190,866	539,152
Riverside	339,670,578	9,334,987	9,556,077	221,090	347,433,930	9,912,908	10,143,041	230,132	349,380,161	10,187,911	10,422,555	234,644	357,065,622	10,306,599	10,543,222	236,623
Total Other	**5,448,932,887**	**191,159,546**	**195,048,307**	**3,888,760**	**5,271,335,455**	**220,073,918**	**223,088,100**	**3,014,182**	**5,221,924,877**	**243,161,209**	**245,271,434**	**2,110,226**	**5,268,624,975**	**257,007,873**	**258,921,190**	**1,913,317**
Total	**11,868,280,676**	**459,307,150**	**464,476,358**	**5,169,208**	**11,572,946,628**	**504,137,184**	**508,402,886**	**4,265,702**	**11,689,915,009**	**524,044,032**	**527,395,133**	**3,351,101**	**11,810,021,828**	**553,460,588**	**556,601,126**	**3,140,539**

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Allen S King														
		Plant													
		Beginning Balance	708,724,388	708,725,095	708,725,115	708,729,111	708,786,679	708,751,972	708,754,848	708,777,347	708,786,421	708,812,678	709,180,068	710,953,194	
		Retirements	-	-	-	-	(35,751)	-	-	-	-	-	-	-	
		Additions	706	20	3,996	57,568	1,044	2,876	22,499	9,074	26,257	367,389	1,773,126	115,380	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	708,725,095	708,725,115	708,729,111	708,786,679	708,751,972	708,754,848	708,777,347	708,786,421	708,812,678	709,180,068	710,953,194	711,068,573	
		Reserve													
	Original	Remaining Life (Mos)	198	197	196	195	194	193	192	191	190	189	188	187	
		Net Salvage Rate	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	
	Proposed	Remaining Life (Mos)	198	197	196	195	194	193	192	191	190	189	188	187	
		Net Salvage Rate	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	
	Original	Beginning Balance	334,940,040	337,121,355	339,302,671	341,483,999	343,665,497	345,987,335	348,168,081	350,340,990	352,516,377	354,687,463	356,833,751	359,000,778	
		Depr Expense	2,181,314	2,181,316	2,181,327	2,181,498	2,181,694	2,180,745	2,180,838	2,180,962	2,181,104	2,182,353	2,188,666	2,194,359	26,196,175
		Cost of Removal	-	0	-	-	(12,795)	-	(7,929)	(5,576)	(10,018)	(36,065)	(21,639)	(64,281)	
		Salvage	-	-	-	-	188,690	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(35,751)	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	337,121,355	339,302,671	341,483,999	343,665,497	345,987,335	348,168,081	350,340,990	352,516,377	354,687,463	356,833,751	359,000,778	361,130,856	
	Proposed	Beginning Balance	334,676,008	336,894,450	339,112,894	341,331,349	343,549,977	345,908,946	348,126,821	350,336,860	352,549,377	354,757,595	356,941,025	359,145,251	
		Depr Expense	2,218,441	2,218,443	2,218,455	2,218,627	2,218,825	2,217,874	2,217,967	2,218,093	2,218,235	2,219,495	2,225,865	2,231,608	26,641,929
		Cost of Removal	-	0	-	-	(12,795)	-	(7,929)	(5,576)	(10,018)	(36,065)	(21,639)	(64,281)	
		Salvage	-	-	-	-	188,690	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(35,751)	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	336,894,450	339,112,894	341,331,349	343,549,977	345,908,946	348,126,821	350,336,860	352,549,377	354,757,595	356,941,025	359,145,251	361,312,578	
	Change	Beginning Balance	(264,033)	(226,905)	(189,777)	(152,649)	(115,520)	(78,389)	(41,260)	(4,130)	33,000	70,132	107,274	144,473	
		Depr Expense	37,128	37,128	37,128	37,129	37,131	37,129	37,130	37,131	37,132	37,142	37,199	37,249	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(226,905)**	**(189,777)**	**(152,649)**	**(115,520)**	**(78,389)**	**(41,260)**	**(4,130)**	**33,000**	**70,132**	**107,274**	**144,473**	**181,722**	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Red Wing**														
		Plant													
		Beginning Balance	67,095,552	67,093,936	66,539,493	67,146,502	69,973,766	70,124,607	70,115,492	70,130,154	70,165,119	70,225,467	70,409,506	70,550,632	
		Retirements	-	(571,456)	-	-	-	(92,735)	-	-	-	-	-	-	
		Additions	(1,615)	17,013	607,009	2,827,263	150,842	83,620	14,662	34,965	60,349	184,038	141,127	207,330	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	67,093,936	66,539,493	67,146,502	69,973,766	70,124,607	70,115,492	70,130,154	70,165,119	70,225,467	70,409,506	70,550,632	70,757,962	
		Reserve													
	Original	Remaining Life (Mos)	84	83	82	81	80	79	78	77	76	75	74	73	
		Net Salvage Rate	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	
	Proposed	Remaining Life (Mos)	84	83	82	81	80	79	78	77	76	75	74	73	
		Net Salvage Rate	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	
	Original	Beginning Balance	63,941,559	64,201,045	63,771,555	64,035,643	64,327,555	64,643,101	64,831,511	64,785,959	65,103,596	65,422,557	65,731,624	66,050,442	
		Depr Expense	259,590	260,423	264,071	291,158	314,938	317,057	320,172	322,992	323,854	326,238	329,145	332,304	3,661,941
		Cost of Removal	-	(118,399)	-	-	-	(35,816)	(375,957)	(15,179)	(13,661)	(49,180)	(29,508)	(24,757)	
		Salvage	-	-	-	-	-	-	10,254	9,913	8,922	32,119	19,271	13,008	
		Retirements	-	(571,456)	-	-	-	(92,735)	-	-	-	-	-	-	
		Transfers/Adjustments	(105)	(58)	17	753	609	(96)	(23)	(89)	(153)	(110)	(90)	(86)	
		Ending Balance	64,201,045	63,771,555	64,035,643	64,327,555	64,643,101	64,831,511	64,785,959	65,103,596	65,422,557	65,731,624	66,050,442	66,370,911	
	Proposed	Beginning Balance	63,965,081	64,189,940	63,725,820	63,955,414	64,211,920	64,491,261	64,643,401	64,561,602	64,842,980	65,125,655	65,398,364	65,680,731	
		Depr Expense	224,964	225,793	229,577	255,753	278,732	280,788	283,927	286,732	287,567	289,881	292,694	295,750	3,232,156
		Cost of Removal	-	(118,399)	-	-	-	(35,816)	(375,957)	(15,179)	(13,661)	(49,180)	(29,508)	(24,757)	
		Salvage	-	-	-	-	-	-	10,254	9,913	8,922	32,119	19,271	13,008	
		Retirements	-	(571,456)	-	-	-	(92,735)	-	-	-	-	-	-	
		Transfers/Adjustments	(105)	(58)	17	753	609	(96)	(23)	(89)	(153)	(110)	(90)	(86)	
		Ending Balance	64,189,940	63,725,820	63,955,414	64,211,920	64,491,261	64,643,401	64,561,602	64,842,980	65,125,655	65,398,364	65,680,731	65,964,647	
	Change	Beginning Balance	23,521	(11,105)	(45,735)	(80,229)	(115,635)	(151,841)	(188,111)	(224,356)	(260,616)	(296,903)	(333,259)	(369,710)	
		Depr Expense	(34,626)	(34,630)	(34,494)	(35,406)	(36,206)	(36,270)	(36,246)	(36,260)	(36,287)	(36,357)	(36,451)	(36,554)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(11,105)**	**(45,735)**	**(80,229)**	**(115,635)**	**(151,841)**	**(188,111)**	**(224,356)**	**(260,616)**	**(296,903)**	**(333,259)**	**(369,710)**	**(406,264)**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Sherco 1														
		Plant													
		Beginning Balance	492,053,949	492,053,949	491,601,225	491,802,597	491,960,199	496,090,552	496,189,238	496,603,191	497,060,474	497,740,660	498,824,283	499,475,498	
		Retirements	-	(452,724)	-	-	-	(98,951)	-	-	-	-	-	-	
		Additions	-	-	201,371	157,603	4,130,353	197,637	413,953	457,284	680,185	1,083,623	651,215	730,196	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	492,053,949	491,601,225	491,802,597	491,960,199	496,090,552	496,189,238	496,603,191	497,060,474	497,740,660	498,824,283	499,475,498	500,205,694	
		Reserve													
	Original	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	420,712,610	423,148,115	424,974,239	427,413,262	429,855,915	432,342,674	434,722,713	437,089,305	439,368,654	441,916,827	444,353,173	446,870,980	
		Depr Expense	2,435,559	2,436,899	2,439,076	2,442,704	2,486,810	2,532,624	2,540,980	2,555,741	2,570,150	2,591,810	2,614,315	2,632,954	30,279,621
		Cost of Removal	-	(157,973)	-	-	-	(53,580)	(174,339)	(386,572)	(21,931)	(155,418)	(96,463)	(138,628)	
		Salvage	-	-	-	-	-	-	-	110,229	-	-	-	-	
		Retirements	-	(452,724)	-	-	-	(98,951)	-	-	-	-	-	-	
		Transfers/Adjustments	(54)	(79)	(52)	(52)	(50)	(54)	(49)	(48)	(47)	(46)	(45)	(44)	
		Ending Balance	423,148,115	424,974,239	427,413,262	429,855,915	432,342,674	434,722,713	437,089,305	439,368,654	441,916,827	444,353,173	446,870,980	449,365,262	
	Proposed	Beginning Balance	420,561,153	422,990,982	424,811,429	427,244,782	429,681,761	432,162,808	434,537,095	436,897,932	439,171,518	441,713,917	444,144,471	446,656,469	
		Depr Expense	2,429,883	2,431,223	2,433,405	2,437,030	2,481,098	2,526,872	2,535,225	2,549,978	2,564,375	2,586,018	2,608,506	2,627,130	30,210,744
		Cost of Removal	-	(157,973)	-	-	-	(53,580)	(174,339)	(386,572)	(21,931)	(155,418)	(96,463)	(138,628)	
		Salvage	-	-	-	-	-	-	-	110,229	-	-	-	-	
		Retirements	-	(452,724)	-	-	-	(98,951)	-	-	-	-	-	-	
		Transfers/Adjustments	(54)	(79)	(52)	(52)	(50)	(54)	(49)	(48)	(47)	(46)	(45)	(44)	
		Ending Balance	422,990,982	424,811,429	427,244,782	429,681,761	432,162,808	434,537,095	436,897,932	439,171,518	441,713,917	444,144,471	446,656,469	449,144,928	
	Change	Beginning Balance	(151,457)	(157,133)	(162,810)	(168,481)	(174,154)	(179,866)	(185,618)	(191,373)	(197,136)	(202,910)	(208,702)	(214,511)	
		Depr Expense	(5,677)	(5,677)	(5,671)	(5,674)	(5,712)	(5,751)	(5,755)	(5,763)	(5,774)	(5,792)	(5,809)	(5,823)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(157,133)**	**(162,810)**	**(168,481)**	**(174,154)**	**(179,866)**	**(185,618)**	**(191,373)**	**(197,136)**	**(202,910)**	**(208,702)**	**(214,511)**	**(220,334)**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Sherco 2														
		Plant													
		Beginning Balance	226,303,986	226,303,986	226,136,072	226,134,326	226,251,792	226,252,743	226,211,255	226,214,481	226,224,653	226,413,110	226,522,107	226,651,602	
		Retirements	-	(167,914)	-	-	-	(41,489)	-	-	-	-	-	-	
		Additions	-	-	(1,747)	117,467	951	-	3,226	10,173	188,457	108,996	129,496	79,982	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	226,303,986	226,136,072	226,134,326	226,251,792	226,252,743	226,211,255	226,214,481	226,224,653	226,413,110	226,522,107	226,651,602	226,731,584	
		Reserve													
	Original	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	223,398,293	224,952,892	226,319,923	227,874,176	229,431,588	230,992,394	232,500,225	234,012,638	235,575,046	237,144,930	238,721,478	240,311,008	
		Depr Expense	1,554,323	1,554,748	1,553,986	1,557,147	1,560,545	1,560,871	1,562,331	1,564,309	1,571,572	1,583,275	1,593,468	1,605,886	18,822,461
		Cost of Removal	-	(20,109)	-	-	-	(11,818)	(50,182)	(2,153)	(1,938)	(6,976)	(4,186)	(77,892)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(167,914)	-	-	-	(41,489)	-	-	-	-	-	-	
		Transfers/Adjustments	275	306	267	264	261	268	264	252	250	250	248	261	
		Ending Balance	224,952,892	226,319,923	227,874,176	229,431,588	230,992,394	232,500,225	234,012,638	235,575,046	237,144,930	238,721,478	240,311,008	241,839,264	
	Proposed	Beginning Balance	223,197,163	224,750,713	226,116,695	227,669,907	229,226,275	230,786,034	232,292,818	233,804,186	235,365,549	236,934,381	238,509,868	240,098,329	
		Depr Expense	1,553,274	1,553,699	1,552,945	1,556,103	1,559,498	1,559,824	1,561,286	1,563,264	1,570,521	1,582,213	1,592,398	1,604,808	18,809,833
		Cost of Removal	-	(20,109)	-	-	-	(11,818)	(50,182)	(2,153)	(1,938)	(6,976)	(4,186)	(77,892)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(167,914)	-	-	-	(41,489)	-	-	-	-	-	-	
		Transfers/Adjustments	275	306	267	264	261	268	264	252	250	250	248	261	
		Ending Balance	224,750,713	226,116,695	227,669,907	229,226,275	230,786,034	232,292,818	233,804,186	235,365,549	236,934,381	238,509,868	240,098,329	241,625,506	
	Change	Beginning Balance	(201,130)	(202,179)	(203,228)	(204,269)	(205,313)	(206,360)	(207,407)	(208,452)	(209,497)	(210,548)	(211,609)	(212,679)	
		Depr Expense	(1,049)	(1,049)	(1,041)	(1,044)	(1,047)	(1,047)	(1,045)	(1,045)	(1,051)	(1,061)	(1,070)	(1,078)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(202,179)**	**(203,228)**	**(204,269)**	**(205,313)**	**(206,360)**	**(207,407)**	**(208,452)**	**(209,497)**	**(210,548)**	**(211,609)**	**(212,679)**	**(213,757)**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Sherco 2 - FERC 311														
		Plant													
		Beginning Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Reserve													
	Original	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	285,701	287,407	289,112	290,818	292,524	294,230	295,935	297,641	299,347	301,053	302,758	304,464	
		Depr Expense	1,706	1,706	1,706	1,706	1,706	1,706	1,706	1,706	1,706	1,705	1,705	1,705	20,466
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	287,407	289,112	290,818	292,524	294,230	295,935	297,641	299,347	301,053	302,758	304,464	306,170	
	Proposed	Beginning Balance	285,701	287,401	289,101	290,801	292,501	294,202	295,902	297,602	299,302	301,002	302,702	304,402	
		Depr Expense	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	20,399
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	287,401	289,101	290,801	292,501	294,202	295,902	297,602	299,302	301,002	302,702	304,402	306,102	
	Change	Beginning Balance	-	(6)	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(51)	(56)	(62)	
		Depr Expense	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(6)**	**(11)**	**(17)**	**(22)**	**(28)**	**(34)**	**(39)**	**(45)**	**(51)**	**(56)**	**(62)**	**(67)**	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 3**														
		Plant													
		Beginning Balance	776,440,159	776,545,851	773,663,006	773,975,635	774,900,882	774,941,870	773,763,875	774,530,253	774,565,519	786,487,399	788,237,155	788,885,521	
		Retirements	-	(2,911,898)	-	-	-	(1,269,869)	-	-	-	-	-	-	
		Additions	105,693	29,053	312,630	925,247	40,988	91,874	766,379	35,265	11,921,881	1,749,755	648,367	608,112	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	776,545,851	773,663,006	773,975,635	774,900,882	774,941,870	773,763,875	774,530,253	774,565,519	786,487,399	788,237,155	788,885,521	789,493,633	
		Reserve													
	Original	Remaining Life (Mos)	168	167	166	165	164	163	162	161	160	159	158	157	
		Net Salvage Rate	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	
	Proposed	Remaining Life (Mos)	168	167	166	165	164	163	162	161	160	159	158	157	
		Net Salvage Rate	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	
	Original	Beginning Balance	545,272,049	546,897,949	544,639,017	546,271,401	547,907,679	549,547,063	549,539,341	549,217,688	550,855,387	552,539,479	554,224,262	552,175,070	
		Depr Expense	1,625,902	1,629,250	1,632,328	1,636,282	1,639,387	1,640,981	1,650,647	1,659,422	1,698,920	1,744,473	1,764,728	1,781,334	20,103,655
		Cost of Removal	-	(975,978)	58	(2)	-	(379,758)	(1,986,371)	(22,348)	(15,390)	(61,720)	(3,815,135)	(77,443)	
		Salvage	-	(302)	-	-	-	926	14,074	627	564	2,031	1,219	823	
		Retirements	-	(2,911,898)	-	-	-	(1,269,869)	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(3)	(2)	(2)	(2)	(3)	(3)	(2)	(2)	(2)	(3)	(2)	
		Ending Balance	546,897,949	544,639,017	546,271,401	547,907,679	549,547,063	549,539,341	549,217,688	550,855,387	552,539,479	554,224,262	552,175,070	553,879,781	
	Proposed	Beginning Balance	545,037,078	546,779,926	544,637,953	546,386,882	548,139,799	549,895,896	550,004,897	549,799,838	551,554,192	553,355,874	555,159,321	553,228,984	
		Depr Expense	1,742,850	1,746,208	1,748,874	1,752,921	1,756,100	1,757,704	1,767,241	1,776,078	1,816,510	1,863,138	1,883,582	1,900,288	21,511,494
		Cost of Removal	-	(975,978)	58	(2)	-	(379,758)	(1,986,371)	(22,348)	(15,390)	(61,720)	(3,815,135)	(77,443)	
		Salvage	-	(302)	-	-	-	926	14,074	627	564	2,031	1,219	823	
		Retirements	-	(2,911,898)	-	-	-	(1,269,869)	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(3)	(2)	(2)	(2)	(3)	(3)	(2)	(2)	(2)	(3)	(2)	
		Ending Balance	546,779,926	544,637,953	546,386,882	548,139,799	549,895,896	550,004,897	549,799,838	551,554,192	553,355,874	555,159,321	553,228,984	555,052,649	
	Change	Beginning Balance	(234,971)	(118,023)	(1,065)	115,481	232,120	348,833	465,556	582,149	698,805	816,395	935,059	1,053,914	
		Depr Expense	116,948	116,958	116,545	116,639	116,713	116,723	116,593	116,656	117,590	118,665	118,854	118,954	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(118,023)**	**(1,065)**	**115,481**	**232,120**	**348,833**	**465,556**	**582,149**	**698,805**	**816,395**	**935,059**	**1,053,914**	**1,172,868**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Wilmarth														
		Plant													
		Beginning Balance	62,480,165	62,518,224	62,684,728	62,848,610	62,849,661	62,850,430	62,403,143	62,421,774	62,462,822	62,860,745	63,094,340	64,832,542	
		Retirements	-	(202,137)	-	-	-	(465,930)	-	-	-	-	-	-	
		Additions	38,059	368,641	163,883	1,051	769	18,644	18,630	41,048	397,923	233,595	1,738,202	87,447	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	62,518,224	62,684,728	62,848,610	62,849,661	62,850,430	62,403,143	62,421,774	62,462,822	62,860,745	63,094,340	64,832,542	64,919,989	
		Reserve													
	Original	Remaining Life (Mos)	84	83	82	81	80	79	78	77	76	75	74	73	
		Net Salvage Rate	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	
	Proposed	Remaining Life (Mos)	84	83	82	81	80	79	78	77	76	75	74	73	
		Net Salvage Rate	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	
	Original	Beginning Balance	59,718,933	59,951,400	59,597,966	59,841,788	60,086,815	60,331,837	60,055,231	60,267,064	60,503,744	60,743,745	60,964,724	61,216,768	
		Depr Expense	232,501	237,952	243,782	245,073	245,088	245,601	244,875	245,640	249,422	255,051	272,312	288,609	3,005,907
		Cost of Removal	-	(389,309)	-	-	-	(56,237)	(32,981)	(8,905)	(9,414)	(34,092)	(20,455)	(44,363)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(202,137)	-	-	-	(465,930)	-	-	-	-	-	-	
		Transfers/Adjustments	(33)	60	39	(46)	(67)	(39)	(62)	(54)	(8)	20	188	165	
		Ending Balance	59,951,400	59,597,966	59,841,788	60,086,815	60,331,837	60,055,231	60,267,064	60,503,744	60,743,745	60,964,724	61,216,768	61,461,179	
	Proposed	Beginning Balance	59,727,001	59,951,933	59,590,938	59,827,191	60,064,639	60,302,081	60,017,895	60,222,205	60,451,359	60,683,804	60,897,185	61,141,498	
		Depr Expense	224,964	230,391	236,214	237,494	237,509	238,021	237,353	238,113	241,867	247,453	264,581	280,753	2,914,712
		Cost of Removal	-	(389,309)	-	-	-	(56,237)	(32,981)	(8,905)	(9,414)	(34,092)	(20,455)	(44,363)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(202,137)	-	-	-	(465,930)	-	-	-	-	-	-	
		Transfers/Adjustments	(33)	60	39	(46)	(67)	(39)	(62)	(54)	(8)	20	188	165	
		Ending Balance	59,951,933	59,590,938	59,827,191	60,064,639	60,302,081	60,017,895	60,222,205	60,451,359	60,683,804	60,897,185	61,141,498	61,378,053	
	Change	Beginning Balance	8,069	532	(7,029)	(14,597)	(22,176)	(29,755)	(37,336)	(44,858)	(52,385)	(59,941)	(67,539)	(75,270)	
		Depr Expense	(7,536)	(7,561)	(7,569)	(7,579)	(7,579)	(7,580)	(7,523)	(7,527)	(7,556)	(7,598)	(7,731)	(7,856)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**532**	**(7,029)**	**(14,597)**	**(22,176)**	**(29,755)**	**(37,336)**	**(44,858)**	**(52,385)**	**(59,941)**	**(67,539)**	**(75,270)**	**(83,126)**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Allen S King**														
		Plant													
		Beginning Balance	711,068,573	711,072,089	711,074,567	711,078,229	711,084,179	711,465,769	711,739,218	711,844,419	711,865,044	711,886,451	713,352,093	713,477,959	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	3,516	2,478	3,662	5,950	381,589	273,449	105,201	20,626	21,407	1,465,642	125,866	135,232	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	711,072,089	711,074,567	711,078,229	711,084,179	711,465,769	711,739,218	711,844,419	711,865,044	711,886,451	713,352,093	713,477,959	713,613,191	
		Reserve													
	Original	Remaining Life (Mos)	186	185	184	183	182	181	180	179	178	177	176	175	
		Net Salvage Rate	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	
	Proposed	Remaining Life (Mos)	186	185	184	183	182	181	180	179	178	177	176	175	
		Net Salvage Rate	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	
	Original	Beginning Balance	361,130,856	363,063,633	365,259,596	367,455,416	369,650,950	371,845,319	374,044,184	376,244,223	378,424,161	380,619,418	382,803,630	385,001,510	
		Depr Expense	2,195,584	2,196,313	2,196,333	2,196,365	2,197,528	2,199,497	2,200,638	2,201,079	2,201,283	2,205,907	2,210,897	2,211,924	26,413,349
		Cost of Removal	(262,808)	(350)	(514)	(832)	(3,160)	(632)	(600)	(21,141)	(6,027)	(21,696)	(13,018)	(63,787)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	0	0	0	0	1	
		Ending Balance	363,063,633	365,259,596	367,455,416	369,650,950	371,845,319	374,044,184	376,244,223	378,424,161	380,619,418	382,803,630	385,001,510	387,149,648	
	Proposed	Beginning Balance	361,312,578	363,282,608	365,515,824	367,748,896	369,981,684	372,213,317	374,449,464	376,686,794	378,904,029	381,136,583	383,358,134	385,593,398	
		Depr Expense	2,232,837	2,233,566	2,233,586	2,233,619	2,234,792	2,236,779	2,237,931	2,238,375	2,238,580	2,243,246	2,248,282	2,249,316	26,860,907
		Cost of Removal	(262,808)	(350)	(514)	(832)	(3,160)	(632)	(600)	(21,141)	(6,027)	(21,696)	(13,018)	(63,787)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	0	0	0	0	1	
		Ending Balance	363,282,608	365,515,824	367,748,896	369,981,684	372,213,317	374,449,464	376,686,794	378,904,029	381,136,583	383,358,134	385,593,398	387,778,928	
	Change	Beginning Balance	181,722	218,975	256,227	293,480	330,734	367,997	405,279	442,572	479,868	517,165	554,504	591,888	
		Depr Expense	37,253	37,253	37,253	37,253	37,264	37,282	37,292	37,296	37,297	37,339	37,384	37,392	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**218,975**	**256,227**	**293,480**	**330,734**	**367,997**	**405,279**	**442,572**	**479,868**	**517,165**	**554,504**	**591,888**	**629,280**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Red Wing														
		Plant													
		Beginning Balance	70,757,962	70,763,126	70,768,360	74,627,115	75,905,796	77,261,357	77,275,009	77,288,494	77,317,695	77,348,642	77,478,651	77,571,963	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	5,163	5,234	3,858,755	1,278,681	1,355,561	13,652	13,486	29,201	30,947	130,009	93,312	73,884	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	70,763,126	70,768,360	74,627,115	75,905,796	77,261,357	77,275,009	77,288,494	77,317,695	77,348,642	77,478,651	77,571,963	77,645,847	
		Reserve													
	Original	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	
	Proposed	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	
	Original	Beginning Balance	66,370,911	66,704,803	67,038,744	67,408,839	67,826,632	68,267,446	68,265,279	68,101,971	68,308,698	68,784,954	69,261,594	69,741,266	
		Depr Expense	334,186	334,284	369,556	417,126	441,899	458,386	466,912	474,241	476,936	478,608	480,925	489,269	5,222,327
		Cost of Removal	(487)	(477)	(701)	(1,134)	(4,309)	(461,362)	(630,819)	(268,499)	(1,400)	(5,040)	(3,024)	(804,991)	
		Salvage	318	312	458	741	2,814	563	535	1,016	914	3,292	1,975	1,333	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(124)	(177)	783	1,060	409	247	64	(31)	(194)	(220)	(204)	53	
		Ending Balance	66,704,803	67,038,744	67,408,839	67,826,632	68,267,446	68,265,279	68,101,971	68,308,698	68,784,954	69,261,594	69,741,266	69,426,929	
	Proposed	Beginning Balance	65,964,647	66,261,922	66,559,243	66,891,531	67,269,915	67,670,488	67,627,642	67,423,644	67,589,668	68,025,201	68,461,062	68,899,879	
		Depr Expense	297,568	297,663	331,749	377,719	401,658	417,706	426,223	433,538	436,212	437,830	440,069	448,354	4,746,289
		Cost of Removal	(487)	(477)	(701)	(1,134)	(4,309)	(461,362)	(630,819)	(268,499)	(1,400)	(5,040)	(3,024)	(804,991)	
		Salvage	318	312	458	741	2,814	563	535	1,016	914	3,292	1,975	1,333	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(124)	(177)	783	1,060	409	247	64	(31)	(194)	(220)	(204)	53	
		Ending Balance	66,261,922	66,559,243	66,891,531	67,269,915	67,670,488	67,627,642	67,423,644	67,589,668	68,025,201	68,461,062	68,899,879	68,544,627	
	Change	Beginning Balance	(406,264)	(442,881)	(479,502)	(517,309)	(556,717)	(596,958)	(637,638)	(678,327)	(719,030)	(759,753)	(800,532)	(841,387)	
		Depr Expense	(36,617)	(36,620)	(37,807)	(39,408)	(40,241)	(40,680)	(40,689)	(40,703)	(40,723)	(40,778)	(40,856)	(40,915)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(442,881)**	**(479,502)**	**(517,309)**	**(556,717)**	**(596,958)**	**(637,638)**	**(678,327)**	**(719,030)**	**(759,753)**	**(800,532)**	**(841,387)**	**(882,302)**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 1**														
		Plant													
		Beginning Balance	500,205,694	500,243,226	500,282,497	500,305,223	500,346,932	500,537,835	500,584,127	500,636,245	500,951,628	501,156,167	502,262,451	502,682,062	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	37,532	39,271	22,725	41,710	190,903	46,292	52,118	315,383	204,538	1,106,284	419,612	379,995	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	500,243,226	500,282,497	500,305,223	500,346,932	500,537,835	500,584,127	500,636,245	500,951,628	501,156,167	502,262,451	502,682,062	503,062,058	
		Reserve													
	Original	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	449,365,262	452,008,057	454,650,302	457,294,543	459,938,948	462,581,402	465,232,666	467,885,382	470,542,126	473,206,668	475,879,134	478,517,214	
		Depr Expense	2,643,619	2,644,594	2,645,409	2,646,267	2,649,413	2,652,687	2,654,070	2,659,281	2,666,828	2,686,395	2,710,663	2,726,295	31,985,521
		Cost of Removal	(782)	(2,307)	(1,126)	(1,820)	(6,917)	(1,383)	(1,314)	(2,497)	(2,247)	(13,894)	(72,554)	(162,974)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(43)	(42)	(42)	(42)	(41)	(41)	(40)	(39)	(38)	(35)	(29)	(21)	
		Ending Balance	452,008,057	454,650,302	457,294,543	459,938,948	462,581,402	465,232,666	467,885,382	470,542,126	473,206,668	475,879,134	478,517,214	481,080,513	
	Proposed	Beginning Balance	449,144,928	451,781,892	454,418,305	457,056,713	459,695,285	462,331,904	464,977,329	467,624,205	470,275,104	472,933,796	475,600,394	478,232,586	
		Depr Expense	2,637,788	2,638,762	2,639,576	2,640,434	2,643,577	2,646,849	2,648,230	2,653,436	2,660,977	2,680,528	2,704,775	2,720,396	31,915,329
		Cost of Removal	(782)	(2,307)	(1,126)	(1,820)	(6,917)	(1,383)	(1,314)	(2,497)	(2,247)	(13,894)	(72,554)	(162,974)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(43)	(42)	(42)	(42)	(41)	(41)	(40)	(39)	(38)	(35)	(29)	(21)	
		Ending Balance	451,781,892	454,418,305	457,056,713	459,695,285	462,331,904	464,977,329	467,624,205	470,275,104	472,933,796	475,600,394	478,232,586	480,789,987	
	Change	Beginning Balance	(220,334)	(226,165)	(231,997)	(237,829)	(243,663)	(249,499)	(255,337)	(261,177)	(267,021)	(272,872)	(278,740)	(284,628)	
		Depr Expense	(5,831)	(5,832)	(5,833)	(5,833)	(5,836)	(5,839)	(5,840)	(5,844)	(5,851)	(5,868)	(5,888)	(5,899)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(226,165)**	**(231,997)**	**(237,829)**	**(243,663)**	**(249,499)**	**(255,337)**	**(261,177)**	**(267,021)**	**(272,872)**	**(278,740)**	**(284,628)**	**(290,526)**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 2**														
		Plant													
		Beginning Balance	226,731,584	226,733,536	226,736,061	226,740,695	226,749,728	226,790,230	227,046,038	227,096,336	227,159,386	227,183,619	227,590,620	227,663,676	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	(227,911,389)	
		Additions	1,953	2,525	4,633	9,033	40,502	255,808	50,298	63,050	24,233	407,001	73,056	247,713	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	226,733,536	226,736,061	226,740,695	226,749,728	226,790,230	227,046,038	227,096,336	227,159,386	227,183,619	227,590,620	227,663,676	(0)	
		Reserve													
	Original	Remaining Life (Mos)	12	11	10	9	8	7	6	5	4	3	2	1	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	12	11	10	9	8	7	6	5	4	3	2	1	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	241,839,264	243,452,486	245,065,925	246,679,725	248,294,325	249,912,057	251,554,681	253,226,681	254,868,878	256,577,087	258,367,661	260,284,958	
		Depr Expense	1,613,046	1,613,265	1,613,662	1,614,525	1,618,110	1,642,511	1,671,878	1,689,670	1,708,168	1,791,035	1,933,443	2,208,656	20,717,969
		Cost of Removal	(69)	(68)	(100)	(161)	(611)	(122)	(116)	(47,721)	(199)	(715)	(16,429)	(86,090)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	(227,911,389)	
		Transfers/Adjustments	245	242	238	235	233	235	238	248	239	254	283	(78,665)	
		Ending Balance	243,452,486	245,065,925	246,679,725	248,294,325	249,912,057	251,554,681	253,226,681	254,868,878	256,577,087	258,367,661	260,284,958	34,417,471	
	Proposed	Beginning Balance	241,625,506	243,237,647	244,850,005	246,462,724	248,076,240	249,692,887	251,334,404	253,005,271	254,646,325	256,353,379	258,142,727	260,058,678	
		Depr Expense	1,611,965	1,612,184	1,612,580	1,613,442	1,617,024	1,641,404	1,670,745	1,688,527	1,707,013	1,789,809	1,932,097	2,207,149	20,703,938
		Cost of Removal	(69)	(68)	(100)	(161)	(611)	(122)	(116)	(47,721)	(199)	(715)	(16,429)	(86,090)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	(227,911,389)	
		Transfers/Adjustments	245	242	238	235	233	235	238	248	239	254	283	(78,665)	
		Ending Balance	243,237,647	244,850,005	246,462,724	248,076,240	249,692,887	251,334,404	253,005,271	254,646,325	256,353,379	258,142,727	260,058,678	34,189,684	
	Change	Beginning Balance	(213,757)	(214,838)	(215,920)	(217,002)	(218,084)	(219,170)	(220,277)	(221,409)	(222,553)	(223,708)	(224,934)	(226,281)	
		Depr Expense	(1,081)	(1,081)	(1,082)	(1,083)	(1,086)	(1,107)	(1,132)	(1,144)	(1,155)	(1,227)	(1,347)	(1,507)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(214,838)**	**(215,920)**	**(217,002)**	**(218,084)**	**(219,170)**	**(220,277)**	**(221,409)**	**(222,553)**	**(223,708)**	**(224,934)**	**(226,281)**	**(227,788)**	

Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
			2022												
Steam	Sherco 2 - FERC 311														
		Plant													
		Beginning Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Reserve													
	Original	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	306,170	307,876	309,581	311,287	312,993	314,698	316,404	318,110	319,815	321,521	323,227	324,932	
		Depr Expense	1,705	1,705	1,705	1,705	1,705	1,705	1,705	1,705	1,705	1,705	1,705	1,705	20,465
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	307,876	309,581	311,287	312,993	314,698	316,404	318,110	319,815	321,521	323,227	324,932	326,638	
	Proposed	Beginning Balance	306,102	307,803	309,503	311,203	312,903	314,603	316,303	318,003	319,703	321,403	323,103	324,803	
		Depr Expense	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	20,398
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	307,803	309,503	311,203	312,903	314,603	316,303	318,003	319,703	321,403	323,103	324,803	326,503	
	Change	Beginning Balance	(67)	(73)	(79)	(84)	(90)	(95)	(101)	(107)	(112)	(118)	(124)	(129)	
		Depr Expense	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(73)**	**(79)**	**(84)**	**(90)**	**(95)**	**(101)**	**(107)**	**(112)**	**(118)**	**(124)**	**(129)**	**(135)**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 3**														
		Plant													
		Beginning Balance	789,493,633	789,733,413	789,750,383	789,763,046	791,548,275	791,632,888	791,646,056	791,657,178	791,783,022	791,925,058	792,703,788	794,775,156	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	239,780	16,971	12,663	1,785,229	84,613	13,168	11,122	125,844	142,036	778,730	2,071,369	481,421	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	789,733,413	789,750,383	789,763,046	791,548,275	791,632,888	791,646,056	791,657,178	791,783,022	791,925,058	792,703,788	794,775,156	795,256,577	
		Reserve													
	Original	Remaining Life (Mos)	156	155	154	153	152	151	150	149	148	147	146	145	
		Net Salvage Rate	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	
	Proposed	Remaining Life (Mos)	156	155	154	153	152	151	150	149	148	147	146	145	
		Net Salvage Rate	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	
	Original	Beginning Balance	553,879,781	555,655,216	557,438,877	559,208,599	560,999,151	562,792,760	564,434,196	566,219,377	568,018,052	569,817,861	571,617,045	573,386,266	
		Depr Expense	1,784,471	1,785,378	1,785,537	1,791,785	1,798,288	1,799,166	1,799,826	1,800,366	1,801,330	1,804,656	1,815,119	1,826,504	21,592,425
		Cost of Removal	(9,053)	(1,735)	(15,842)	(1,277)	(4,854)	(157,764)	(14,678)	(1,752)	(1,577)	(5,678)	(46,021)	(565,227)	
		Salvage	20	20	29	47	178	36	34	64	58	208	125	84	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	
		Ending Balance	555,655,216	557,438,877	559,208,599	560,999,151	562,792,760	564,434,196	566,219,377	568,018,052	569,817,861	571,617,045	573,386,266	574,647,624	
	Proposed	Beginning Balance	555,052,649	556,947,106	558,849,810	560,738,577	562,648,322	564,561,277	566,322,067	568,226,604	570,144,647	572,063,846	573,982,498	575,871,431	
		Depr Expense	1,903,493	1,904,421	1,904,582	1,910,977	1,917,634	1,918,521	1,919,182	1,919,733	1,920,721	1,924,124	1,934,832	1,946,437	23,024,656
		Cost of Removal	(9,053)	(1,735)	(15,842)	(1,277)	(4,854)	(157,764)	(14,678)	(1,752)	(1,577)	(5,678)	(46,021)	(565,227)	
		Salvage	20	20	29	47	178	36	34	64	58	208	125	84	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	
		Ending Balance	556,947,106	558,849,810	560,738,577	562,648,322	564,561,277	566,322,067	568,226,604	570,144,647	572,063,846	573,982,498	575,871,431	577,252,723	
	Change	Beginning Balance	1,172,868	1,291,890	1,410,933	1,529,978	1,649,171	1,768,517	1,887,871	2,007,227	2,126,595	2,245,985	2,365,453	2,485,166	
		Depr Expense	119,022	119,043	119,045	119,192	119,346	119,354	119,356	119,368	119,390	119,469	119,713	119,933	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,291,890**	**1,410,933**	**1,529,978**	**1,649,171**	**1,768,517**	**1,887,871**	**2,007,227**	**2,126,595**	**2,245,985**	**2,365,453**	**2,485,166**	**2,605,099**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Wilmarth														
		Plant													
		Beginning Balance	64,919,989	64,937,954	65,562,955	65,570,826	65,578,565	65,606,698	65,613,395	65,621,148	65,639,285	67,426,014	69,576,535	70,138,446	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	17,965	625,000	7,871	7,740	28,132	6,698	7,753	18,137	1,786,729	2,150,521	561,911	87,987	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	64,937,954	65,562,955	65,570,826	65,578,565	65,606,698	65,613,395	65,621,148	65,639,285	67,426,014	69,576,535	70,138,446	70,226,433	
		Reserve													
	Original	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	
	Proposed	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	
	Original	Beginning Balance	61,461,179	61,750,628	61,488,682	61,797,541	62,101,155	62,368,272	62,678,431	62,988,762	63,298,851	63,627,160	63,992,848	64,298,289	
		Depr Expense	289,847	299,545	309,291	309,480	310,174	310,830	310,979	311,245	329,140	368,794	397,296	406,107	3,952,727
		Cost of Removal	(338)	(561,585)	(486)	(5,786)	(42,987)	(597)	(568)	(1,078)	(970)	(3,494)	(92,096)	(158,915)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(60)	94	55	(80)	(71)	(73)	(80)	(78)	139	388	240	7	
		Ending Balance	61,750,628	61,488,682	61,797,541	62,101,155	62,368,272	62,678,431	62,988,762	63,298,851	63,627,160	63,992,848	64,298,289	64,545,487	
	Proposed	Beginning Balance	61,378,053	61,659,639	61,389,784	61,690,690	61,986,348	62,245,507	62,547,706	62,850,076	63,152,202	63,472,406	63,829,678	64,126,483	
		Depr Expense	281,983	291,636	301,337	301,525	302,216	302,870	303,017	303,282	321,036	360,377	388,661	397,418	3,855,358
		Cost of Removal	(338)	(561,585)	(486)	(5,786)	(42,987)	(597)	(568)	(1,078)	(970)	(3,494)	(92,096)	(158,915)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(60)	94	55	(80)	(71)	(73)	(80)	(78)	139	388	240	7	
		Ending Balance	61,659,639	61,389,784	61,690,690	61,986,348	62,245,507	62,547,706	62,850,076	63,152,202	63,472,406	63,829,678	64,126,483	64,364,992	
	Change	Beginning Balance	(83,126)	(90,989)	(98,898)	(106,852)	(114,807)	(122,764)	(130,725)	(138,686)	(146,649)	(154,754)	(163,170)	(171,806)	
		Depr Expense	(7,863)	(7,909)	(7,954)	(7,955)	(7,958)	(7,960)	(7,961)	(7,963)	(8,104)	(8,417)	(8,636)	(8,689)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(90,989)**	**(98,898)**	**(106,852)**	**(114,807)**	**(122,764)**	**(130,725)**	**(138,686)**	**(146,649)**	**(154,754)**	**(163,170)**	**(171,806)**	**(180,495)**	

			2023												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Allen S King														
		Plant													
		Beginning Balance	713,613,191	713,616,144	713,619,052	713,623,348	713,630,327	714,369,227	714,735,822	714,782,806	714,842,456	714,868,453	715,442,223	715,598,285	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	2,953	2,908	4,296	6,979	738,900	366,595	46,984	59,649	25,997	573,770	156,062	486,225	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	713,616,144	713,619,052	713,623,348	713,630,327	714,369,227	714,735,822	714,782,806	714,842,456	714,868,453	715,442,223	715,598,285	716,084,510	
		Reserve													
	Original	Remaining Life (Mos)	174	173	172	171	170	169	168	167	166	165	164	163	
		Net Salvage Rate	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	
	Proposed	Remaining Life (Mos)	174	173	172	171	170	169	168	167	166	165	164	163	
		Net Salvage Rate	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	
	Original	Beginning Balance	387,149,648	389,361,971	391,574,318	393,786,590	395,998,710	398,211,809	400,428,479	402,648,007	404,810,530	407,028,882	409,238,702	411,452,231	
		Depr Expense	2,212,538	2,212,557	2,212,581	2,212,619	2,215,000	2,218,550	2,219,889	2,220,408	2,220,869	2,222,883	2,225,367	2,228,085	26,621,347
		Cost of Removal	(215)	(210)	(309)	(500)	(1,901)	(1,880)	(361)	(57,886)	(2,518)	(13,063)	(11,838)	(179,456)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	797,509	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	389,361,971	391,574,318	393,786,590	395,998,710	398,211,809	400,428,479	402,648,007	404,810,530	407,028,882	409,238,702	411,452,231	414,298,370	
	Proposed	Beginning Balance	387,778,928	390,028,647	392,278,390	394,528,058	396,777,574	399,028,092	401,282,214	403,539,205	405,739,194	407,995,016	410,242,323	412,493,362	
		Depr Expense	2,249,933	2,249,953	2,249,977	2,250,016	2,252,418	2,256,001	2,257,352	2,257,875	2,258,339	2,260,371	2,262,876	2,265,615	27,070,726
		Cost of Removal	(215)	(210)	(309)	(500)	(1,901)	(1,880)	(361)	(57,886)	(2,518)	(13,063)	(11,838)	(179,456)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	797,509	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	390,028,647	392,278,390	394,528,058	396,777,574	399,028,092	401,282,214	403,539,205	405,739,194	407,995,016	410,242,323	412,493,362	415,377,029	
	Change	Beginning Balance	629,280	666,676	704,072	741,468	778,865	816,283	853,734	891,198	928,664	966,133	1,003,621	1,041,130	
		Depr Expense	37,396	37,396	37,396	37,396	37,418	37,451	37,463	37,467	37,469	37,487	37,510	37,529	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**666,676**	**704,072**	**741,468**	**778,865**	**816,283**	**853,734**	**891,198**	**928,664**	**966,133**	**1,003,621**	**1,041,130**	**1,078,660**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Red Wing														
		Plant													
		Beginning Balance	77,645,847	77,647,731	77,649,734	79,060,555	79,076,703	79,354,027	79,360,717	79,368,507	79,386,829	79,407,929	79,502,317	79,574,149	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	1,884	2,003	1,410,822	16,147	277,324	6,690	7,791	18,321	21,100	94,388	71,832	59,312	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	77,647,731	77,649,734	79,060,555	79,076,703	79,354,027	79,360,717	79,368,507	79,386,829	79,407,929	79,502,317	79,574,149	79,633,461	
		Reserve													
	Original	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	
	Proposed	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	
	Original	Beginning Balance	69,426,929	69,923,585	70,420,113	70,932,532	71,460,926	71,992,293	72,242,287	72,782,520	73,318,046	73,859,122	74,401,544	74,946,182	
		Depr Expense	496,762	496,808	512,375	528,372	531,726	537,641	540,478	540,846	541,385	542,841	544,972	546,688	6,360,894
		Cost of Removal	(50)	(49)	(72)	(116)	(442)	(287,588)	(84)	(5,159)	(143)	(516)	(310)	(209)	
		Salvage	33	32	47	76	288	58	55	104	94	337	202	137	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(90)	(262)	69	63	(206)	(116)	(217)	(264)	(259)	(240)	(226)	(232)	
		Ending Balance	69,923,585	70,420,113	70,932,532	71,460,926	71,992,293	72,242,287	72,782,520	73,318,046	73,859,122	74,401,544	74,946,182	75,492,565	
	Proposed	Beginning Balance	68,544,627	69,000,341	69,455,926	69,926,878	70,413,267	70,902,515	71,110,281	71,608,279	72,101,560	72,600,375	73,100,486	73,602,742	
		Depr Expense	455,820	455,864	470,908	486,367	489,608	495,413	498,244	498,601	499,123	500,531	502,590	504,249	5,857,318
		Cost of Removal	(50)	(49)	(72)	(116)	(442)	(287,588)	(84)	(5,159)	(143)	(516)	(310)	(209)	
		Salvage	33	32	47	76	288	58	55	104	94	337	202	137	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(90)	(262)	69	63	(206)	(116)	(217)	(264)	(259)	(240)	(226)	(232)	
		Ending Balance	69,000,341	69,455,926	69,926,878	70,413,267	70,902,515	71,110,281	71,608,279	72,101,560	72,600,375	73,100,486	73,602,742	74,106,686	
	Change	Beginning Balance	(882,302)	(923,244)	(964,187)	(1,005,654)	(1,047,659)	(1,089,777)	(1,132,006)	(1,174,241)	(1,216,486)	(1,258,748)	(1,301,058)	(1,343,440)	
		Depr Expense	(40,942)	(40,943)	(41,467)	(42,005)	(42,118)	(42,229)	(42,235)	(42,245)	(42,262)	(42,310)	(42,382)	(42,439)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(923,244)**	**(964,187)**	**(1,005,654)**	**(1,047,659)**	**(1,089,777)**	**(1,132,006)**	**(1,174,241)**	**(1,216,486)**	**(1,258,748)**	**(1,301,058)**	**(1,343,440)**	**(1,385,879)**	

Northern States Power Company
Steam Production

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 6
Page 19 of 122

Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
			2023												
Steam	Sherco 1														
		Plant													
		Beginning Balance	503,062,058	503,077,914	503,096,246	503,118,027	503,159,964	503,358,273	503,487,589	503,546,322	503,674,742	504,129,924	505,368,368	505,809,658	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	15,856	18,332	21,781	41,937	198,310	129,316	58,732	128,420	455,181	1,238,445	441,290	383,426	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	503,077,914	503,096,246	503,118,027	503,159,964	503,358,273	503,487,589	503,546,322	503,674,742	504,129,924	505,368,368	505,809,658	506,193,084	
		Reserve													
	Original	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	481,080,513	483,813,647	486,547,419	489,281,384	492,015,488	494,746,342	497,491,989	500,241,442	502,992,926	505,749,097	508,540,922	511,269,007	
		Depr Expense	2,734,917	2,735,530	2,736,269	2,737,467	2,742,019	2,748,330	2,752,028	2,755,865	2,768,163	2,804,755	2,844,454	2,870,047	33,229,843
		Cost of Removal	(1,197)	(1,173)	(1,725)	(2,788)	(10,595)	(2,119)	(2,013)	(3,825)	(11,442)	(12,392)	(115,835)	(212,664)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(585)	(585)	(580)	(575)	(569)	(564)	(561)	(557)	(549)	(538)	(534)	(536)	
		Ending Balance	483,813,647	486,547,419	489,281,384	492,015,488	494,746,342	497,491,989	500,241,442	502,992,926	505,749,097	508,540,922	511,269,007	513,925,854	
	Proposed	Beginning Balance	480,789,987	483,517,217	486,245,084	488,973,144	491,701,342	494,426,287	497,166,018	499,909,554	502,655,116	505,405,355	508,191,217	510,913,306	
		Depr Expense	2,729,013	2,729,625	2,730,364	2,731,561	2,736,109	2,742,414	2,746,109	2,749,943	2,762,231	2,798,792	2,838,459	2,864,035	33,158,656
		Cost of Removal	(1,197)	(1,173)	(1,725)	(2,788)	(10,595)	(2,119)	(2,013)	(3,825)	(11,442)	(12,392)	(115,835)	(212,664)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(585)	(585)	(580)	(575)	(569)	(564)	(561)	(557)	(549)	(538)	(534)	(536)	
		Ending Balance	483,517,217	486,245,084	488,973,144	491,701,342	494,426,287	497,166,018	499,909,554	502,655,116	505,405,355	508,191,217	510,913,306	513,564,141	
	Change	Beginning Balance	(290,526)	(296,430)	(302,335)	(308,240)	(314,146)	(320,055)	(325,971)	(331,889)	(337,810)	(343,742)	(349,705)	(355,701)	
		Depr Expense	(5,904)	(5,904)	(5,905)	(5,906)	(5,910)	(5,915)	(5,918)	(5,921)	(5,932)	(5,963)	(5,996)	(6,012)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(296,430)**	**(302,335)**	**(308,240)**	**(314,146)**	**(320,055)**	**(325,971)**	**(331,889)**	**(337,810)**	**(343,742)**	**(349,705)**	**(355,701)**	**(361,713)**	

Northern States Power Company
Steam Production

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 6
Page 20 of 122

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 2**														
		Plant													
		Beginning Balance	(0)	19,532	39,040	41,269	44,888	58,704	61,481	64,131	69,190	73,765	90,297	100,256	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	19,532	19,509	2,228	3,620	13,816	2,776	2,650	5,059	4,574	16,533	9,959	6,748	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,532	39,040	41,269	44,888	58,704	61,481	64,131	69,190	73,765	90,297	100,256	107,004	
		Reserve													
	Original	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	34,417,471	34,418,642	34,395,684	34,396,743	34,397,562	34,396,608	34,397,586	34,398,592	34,399,189	34,399,876	34,398,529	34,398,313	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	(271)	(24,266)	(391)	(631)	(2,399)	(480)	(456)	(866)	(779)	(2,806)	(1,684)	(1,136)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1,442	1,307	1,449	1,451	1,444	1,459	1,462	1,463	1,466	1,459	1,468	1,475	
		Ending Balance	34,418,642	34,395,684	34,396,743	34,397,562	34,396,608	34,397,586	34,398,592	34,399,189	34,399,876	34,398,529	34,398,313	34,398,652	
	Proposed	Beginning Balance	34,189,684	34,190,855	34,167,896	34,168,955	34,169,775	34,168,820	34,169,799	34,170,805	34,171,402	34,172,089	34,170,741	34,170,526	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	(271)	(24,266)	(391)	(631)	(2,399)	(480)	(456)	(866)	(779)	(2,806)	(1,684)	(1,136)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1,442	1,307	1,449	1,451	1,444	1,459	1,462	1,463	1,466	1,459	1,468	1,475	
		Ending Balance	34,190,855	34,167,896	34,168,955	34,169,775	34,168,820	34,169,799	34,170,805	34,171,402	34,172,089	34,170,741	34,170,526	34,170,864	
	Change	Beginning Balance	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 2 - FERC 311**														
		Plant													
		Beginning Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Reserve													
	Original	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	326,638	328,349	330,059	331,770	333,480	335,190	336,899	338,609	340,318	342,027	343,736	345,445	
		Depr Expense	1,705	1,705	1,705	1,705	1,705	1,705	1,704	1,704	1,704	1,704	1,704	1,703	20,453
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	5	5	5	5	5	5	5	5	5	5	5	5	
		Ending Balance	328,349	330,059	331,770	333,480	335,190	336,899	338,609	340,318	342,027	343,736	345,445	347,153	
	Proposed	Beginning Balance	326,503	328,208	329,913	331,618	333,323	335,027	336,731	338,435	340,138	341,842	343,545	345,248	
		Depr Expense	1,700	1,700	1,699	1,699	1,699	1,699	1,699	1,699	1,698	1,698	1,698	1,698	20,386
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	5	5	5	5	5	5	5	5	5	5	5	5	
		Ending Balance	328,208	329,913	331,618	333,323	335,027	336,731	338,435	340,138	341,842	343,545	345,248	346,951	
	Change	Beginning Balance	(135)	(140)	(146)	(152)	(157)	(163)	(168)	(174)	(180)	(185)	(191)	(197)	
		Depr Expense	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(140)**	**(146)**	**(152)**	**(157)**	**(163)**	**(168)**	**(174)**	**(180)**	**(185)**	**(191)**	**(197)**	**(202)**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Sherco 3														
		Plant													
		Beginning Balance	795,256,577	795,294,585	795,332,893	795,335,799	796,432,452	799,280,373	799,575,550	799,829,213	800,030,580	800,150,041	801,292,554	801,779,325	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	38,008	38,308	2,906	1,096,653	2,847,921	295,177	253,664	201,367	119,460	1,142,513	486,771	107,703	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	795,294,585	795,332,893	795,335,799	796,432,452	799,280,373	799,575,550	799,829,213	800,030,580	800,150,041	801,292,554	801,779,325	801,887,027	
		Reserve													
	Original	Remaining Life (Mos)	144	143	142	141	140	139	138	137	136	135	134	133	
		Net Salvage Rate	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	
	Proposed	Remaining Life (Mos)	144	143	142	141	140	139	138	137	136	135	134	133	
		Net Salvage Rate	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	
	Original	Beginning Balance	574,647,624	576,477,804	578,268,409	580,099,224	581,933,986	583,782,390	585,640,050	587,447,468	589,280,264	591,147,486	593,018,251	594,884,251	
		Depr Expense	1,830,368	1,830,790	1,831,085	1,835,198	1,850,054	1,861,992	1,864,309	1,866,390	1,867,759	1,872,694	1,879,158	1,881,934	22,271,731
		Cost of Removal	(188)	(40,184)	(271)	(438)	(1,666)	(4,333)	(56,893)	(33,598)	(541)	(1,948)	(13,169)	(98,515)	
		Salvage	2	2	3	5	18	4	3	7	6	21	13	9	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	
		Ending Balance	576,477,804	578,268,409	580,099,224	581,933,986	583,782,390	585,640,050	587,447,468	589,280,264	591,147,486	593,018,251	594,884,251	596,667,676	
	Proposed	Beginning Balance	577,252,723	579,202,880	581,113,470	583,064,273	585,019,120	586,987,962	588,966,342	590,894,530	592,848,138	594,836,201	596,827,924	598,815,034	
		Depr Expense	1,950,345	1,950,774	1,951,073	1,955,283	1,970,491	1,982,712	1,985,080	1,987,202	1,988,600	1,993,652	2,000,268	2,003,099	23,718,581
		Cost of Removal	(188)	(40,184)	(271)	(438)	(1,666)	(4,333)	(56,893)	(33,598)	(541)	(1,948)	(13,169)	(98,515)	
		Salvage	2	2	3	5	18	4	3	7	6	21	13	9	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	
		Ending Balance	579,202,880	581,113,470	583,064,273	585,019,120	586,987,962	588,966,342	590,894,530	592,848,138	594,836,201	596,827,924	598,815,034	600,719,625	
	Change	Beginning Balance	2,605,099	2,725,076	2,845,061	2,965,049	3,085,134	3,205,572	3,326,292	3,447,062	3,567,874	3,688,715	3,809,673	3,930,783	
		Depr Expense	119,978	119,984	119,988	120,086	120,438	120,720	120,770	120,812	120,841	120,958	121,110	121,166	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**2,725,076**	**2,845,061**	**2,965,049**	**3,085,134**	**3,205,572**	**3,326,292**	**3,447,062**	**3,567,874**	**3,688,715**	**3,809,673**	**3,930,783**	**4,051,948**	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Wilmarth**														
		Plant													
		Beginning Balance	70,226,433	70,439,489	71,684,365	72,639,746	72,655,904	72,685,399	72,691,264	72,698,219	72,714,828	73,478,997	74,971,581	75,051,330	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	213,055	1,244,876	955,381	16,158	29,496	5,864	6,955	16,609	764,169	1,492,584	79,749	61,346	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	70,439,489	71,684,365	72,639,746	72,655,904	72,685,399	72,691,264	72,698,219	72,714,828	73,478,997	74,971,581	75,051,330	75,112,675	
		Reserve													
	Original	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	
	Proposed	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	
	Original	Beginning Balance	64,545,487	64,750,272	65,175,130	65,629,125	66,019,416	66,306,204	66,776,275	67,246,484	67,716,929	68,196,993	68,705,018	69,188,500	
		Depr Expense	412,341	429,809	453,902	465,366	468,173	470,231	470,384	470,670	480,193	508,251	528,642	531,502	5,689,462
		Cost of Removal	(207,535)	(5,034)	(50)	(75,081)	(181,306)	(61)	(58)	(111)	(99)	(358)	(45,215)	(56,145)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(22)	83	143	6	(79)	(99)	(117)	(115)	(29)	132	55	(101)	
		Ending Balance	64,750,272	65,175,130	65,629,125	66,019,416	66,306,204	66,776,275	67,246,484	67,716,929	68,196,993	68,705,018	69,188,500	69,663,756	
	Proposed	Beginning Balance	64,364,992	64,561,063	64,977,084	65,422,052	65,803,231	66,080,902	66,541,853	67,002,941	67,464,263	67,935,129	68,433,735	68,907,640	
		Depr Expense	403,628	420,971	444,875	456,253	459,056	461,111	461,263	461,547	470,995	498,831	519,065	521,911	5,579,506
		Cost of Removal	(207,535)	(5,034)	(50)	(75,081)	(181,306)	(61)	(58)	(111)	(99)	(358)	(45,215)	(56,145)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(22)	83	143	6	(79)	(99)	(117)	(115)	(29)	132	55	(101)	
		Ending Balance	64,561,063	64,977,084	65,422,052	65,803,231	66,080,902	66,541,853	67,002,941	67,464,263	67,935,129	68,433,735	68,907,640	69,373,305	
	Change	Beginning Balance	(180,495)	(189,209)	(198,046)	(207,073)	(216,186)	(225,302)	(234,422)	(243,543)	(252,666)	(261,864)	(271,283)	(280,860)	
		Depr Expense	(8,714)	(8,837)	(9,027)	(9,112)	(9,116)	(9,120)	(9,121)	(9,123)	(9,198)	(9,419)	(9,577)	(9,591)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(189,209)**	**(198,046)**	**(207,073)**	**(216,186)**	**(225,302)**	**(234,422)**	**(243,543)**	**(252,666)**	**(261,864)**	**(271,283)**	**(280,860)**	**(290,451)**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Allen S King**														
		Plant													
		Beginning Balance	716,084,510	716,119,454	716,122,677	716,128,014	716,666,741	717,589,692	721,150,427	721,172,332	721,244,460	721,290,863	721,460,149	721,580,790	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	34,944	3,223	5,337	538,727	922,951	3,560,735	21,905	72,128	46,404	169,286	120,641	2,182,697	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	716,119,454	716,122,677	716,128,014	716,666,741	717,589,692	721,150,427	721,172,332	721,244,460	721,290,863	721,460,149	721,580,790	723,763,487	
		Reserve													
	Original	Remaining Life (Mos)	162	161	160	159	158	157	156	155	154	153	152	151	
		Net Salvage Rate	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	-8.2%	
	Proposed	Remaining Life (Mos)	162	161	160	159	158	157	156	155	154	153	152	151	
		Net Salvage Rate	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%	
	Original	Beginning Balance	414,298,370	416,512,255	418,737,614	420,962,863	423,189,696	425,419,554	427,662,296	429,922,261	432,113,566	434,374,367	436,625,751	438,887,410	
		Depr Expense	2,225,492	2,225,658	2,225,689	2,227,544	2,232,559	2,248,035	2,260,478	2,261,033	2,261,678	2,262,480	2,263,555	2,271,818	26,966,019
		Cost of Removal	(11,608)	(299)	(440)	(711)	(2,702)	(5,293)	(513)	(69,728)	(878)	(11,097)	(1,896)	(1,280)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	416,512,255	418,737,614	420,962,863	423,189,696	425,419,554	427,662,296	429,922,261	432,113,566	434,374,367	436,625,751	438,887,410	441,157,948	
	Proposed	Beginning Balance	415,377,029	417,628,460	419,891,366	422,154,162	424,418,559	426,686,027	428,966,522	431,264,355	433,493,531	435,792,206	438,081,472	440,381,022	
		Depr Expense	2,263,038	2,263,204	2,263,236	2,265,108	2,270,170	2,285,788	2,298,346	2,298,904	2,299,553	2,300,362	2,301,446	2,309,785	27,418,940
		Cost of Removal	(11,608)	(299)	(440)	(711)	(2,702)	(5,293)	(513)	(69,728)	(878)	(11,097)	(1,896)	(1,280)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	417,628,460	419,891,366	422,154,162	424,418,559	426,686,027	428,966,522	431,264,355	433,493,531	435,792,206	438,081,472	440,381,022	442,689,528	
	Change	Beginning Balance	1,078,660	1,116,205	1,153,752	1,191,299	1,228,863	1,266,473	1,304,226	1,342,094	1,379,965	1,417,840	1,455,721	1,493,613	
		Depr Expense	37,545	37,547	37,547	37,564	37,610	37,753	37,868	37,871	37,875	37,882	37,891	37,968	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,116,205**	**1,153,752**	**1,191,299**	**1,228,863**	**1,266,473**	**1,304,226**	**1,342,094**	**1,379,965**	**1,417,840**	**1,455,721**	**1,493,613**	**1,531,580**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Red Wing														
		Plant													
		Beginning Balance	79,633,461	79,635,017	79,636,761	79,725,651	79,731,757	79,760,710	79,768,222	79,966,033	79,988,505	80,015,320	80,138,204	80,233,678	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	1,556	1,744	88,890	6,106	28,953	7,513	197,810	22,473	26,815	122,884	95,474	79,934	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	79,635,017	79,636,761	79,725,651	79,731,757	79,760,710	79,768,222	79,966,033	79,988,505	80,015,320	80,138,204	80,233,678	80,313,612	
		Reserve													
	Original	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	-27.8%	
	Proposed	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	-23.5%	
	Original	Beginning Balance	75,492,565	76,039,820	76,587,115	77,135,695	77,685,631	78,236,061	78,777,171	79,331,568	79,889,402	80,408,505	80,963,184	81,529,154	
		Depr Expense	547,502	547,553	548,817	550,171	550,686	551,350	554,598	558,036	559,329	562,397	566,173	569,207	6,665,820
		Cost of Removal	(5)	(5)	(7)	(12)	(45)	(10,009)	(9)	(16)	(40,015)	(7,553)	(32)	(21)	
		Salvage	3	3	5	8	30	6	6	11	10	35	21	14	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(246)	(256)	(234)	(231)	(242)	(236)	(199)	(196)	(221)	(200)	(192)	(201)	
		Ending Balance	76,039,820	76,587,115	77,135,695	77,685,631	78,236,061	78,777,171	79,331,568	79,889,402	80,408,505	80,963,184	81,529,154	82,098,153	
	Proposed	Beginning Balance	74,106,686	74,611,474	75,116,301	75,622,371	76,129,752	76,637,608	77,136,128	77,647,828	78,162,851	78,639,115	79,150,873	79,673,799	
		Depr Expense	505,036	505,085	506,307	507,616	508,113	508,759	511,902	515,225	516,491	519,476	523,128	526,061	6,153,198
		Cost of Removal	(5)	(5)	(7)	(12)	(45)	(10,009)	(9)	(16)	(40,015)	(7,553)	(32)	(21)	
		Salvage	3	3	5	8	30	6	6	11	10	35	21	14	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(246)	(256)	(234)	(231)	(242)	(236)	(199)	(196)	(221)	(200)	(192)	(201)	
		Ending Balance	74,611,474	75,116,301	75,622,371	76,129,752	76,637,608	77,136,128	77,647,828	78,162,851	78,639,115	79,150,873	79,673,799	80,199,651	
	Change	Beginning Balance	(1,385,879)	(1,428,345)	(1,470,813)	(1,513,324)	(1,555,880)	(1,598,453)	(1,641,044)	(1,683,740)	(1,726,552)	(1,769,390)	(1,812,311)	(1,855,355)	
		Depr Expense	(42,467)	(42,468)	(42,510)	(42,556)	(42,573)	(42,591)	(42,696)	(42,812)	(42,838)	(42,921)	(43,044)	(43,146)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(1,428,345)**	**(1,470,813)**	**(1,513,324)**	**(1,555,880)**	**(1,598,453)**	**(1,641,044)**	**(1,683,740)**	**(1,726,552)**	**(1,769,390)**	**(1,812,311)**	**(1,855,355)**	**(1,898,501)**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 1**														
		Plant													
		Beginning Balance	506,193,084	506,204,997	506,220,476	506,248,962	506,304,605	506,963,155	507,072,697	507,311,939	507,485,179	507,667,180	508,713,319	509,223,015	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	11,913	15,479	28,486	55,643	658,550	109,542	239,242	173,240	182,001	1,046,139	509,696	826,449	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	506,204,997	506,220,476	506,248,962	506,304,605	506,963,155	507,072,697	507,311,939	507,485,179	507,667,180	508,713,319	509,223,015	510,049,464	
		Reserve													
	Original	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	513,925,854	516,807,807	519,690,566	522,573,883	525,458,314	528,353,787	531,237,600	534,181,705	537,123,162	540,093,692	543,100,649	546,092,409	
		Depr Expense	2,884,020	2,884,795	2,886,054	2,888,525	2,909,548	2,934,538	2,947,194	2,961,861	2,975,441	3,023,310	3,091,467	3,159,021	35,545,773
		Cost of Removal	(1,532)	(1,501)	(2,207)	(3,567)	(13,556)	(50,211)	(2,576)	(19,894)	(4,405)	(15,856)	(99,214)	(116,969)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(535)	(535)	(531)	(526)	(518)	(514)	(513)	(510)	(506)	(497)	(493)	(491)	
		Ending Balance	516,807,807	519,690,566	522,573,883	525,458,314	528,353,787	531,237,600	534,181,705	537,123,162	540,093,692	543,100,649	546,092,409	549,133,970	
	Proposed	Beginning Balance	513,564,141	516,440,074	519,316,812	522,194,107	525,072,514	527,961,946	530,839,696	533,777,730	536,713,104	539,677,539	542,678,360	545,663,929	
		Depr Expense	2,877,999	2,878,774	2,880,033	2,882,501	2,903,506	2,928,476	2,941,123	2,955,777	2,969,346	3,017,174	3,085,275	3,152,778	35,472,762
		Cost of Removal	(1,532)	(1,501)	(2,207)	(3,567)	(13,556)	(50,211)	(2,576)	(19,894)	(4,405)	(15,856)	(99,214)	(116,969)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(535)	(535)	(531)	(526)	(518)	(514)	(513)	(510)	(506)	(497)	(493)	(491)	
		Ending Balance	516,440,074	519,316,812	522,194,107	525,072,514	527,961,946	530,839,696	533,777,730	536,713,104	539,677,539	542,678,360	545,663,929	548,699,246	
	Change	Beginning Balance	(361,713)	(367,733)	(373,754)	(379,776)	(385,800)	(391,841)	(397,903)	(403,975)	(410,059)	(416,153)	(422,289)	(428,481)	
		Depr Expense	(6,020)	(6,021)	(6,022)	(6,024)	(6,042)	(6,062)	(6,072)	(6,084)	(6,095)	(6,136)	(6,191)	(6,243)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(367,733)**	**(373,754)**	**(379,776)**	**(385,800)**	**(391,841)**	**(397,903)**	**(403,975)**	**(410,059)**	**(416,153)**	**(422,289)**	**(428,481)**	**(434,723)**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 2**														
		Plant													
		Beginning Balance	107,004	107,170	107,333	107,574	107,966	109,461	109,762	110,049	110,596	111,091	112,882	113,960	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	166	163	241	392	1,495	301	287	548	495	1,790	1,078	731	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	107,170	107,333	107,574	107,966	109,461	109,762	110,049	110,596	111,091	112,882	113,960	114,690	
		Reserve													
	Original	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	34,398,652	34,400,108	34,401,568	34,403,018	34,404,446	34,405,696	34,407,146	34,408,602	34,410,019	34,411,448	34,412,672	34,414,014	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	(28)	(27)	(40)	(65)	(246)	(49)	(47)	(89)	(80)	(288)	(173)	(116)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1,484	1,487	1,490	1,493	1,495	1,500	1,503	1,506	1,509	1,511	1,515	1,518	
		Ending Balance	34,400,108	34,401,568	34,403,018	34,404,446	34,405,696	34,407,146	34,408,602	34,410,019	34,411,448	34,412,672	34,414,014	34,415,416	
	Proposed	Beginning Balance	34,170,864	34,172,320	34,173,780	34,175,230	34,176,659	34,177,908	34,179,359	34,180,815	34,182,232	34,183,661	34,184,884	34,186,227	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	(28)	(27)	(40)	(65)	(246)	(49)	(47)	(89)	(80)	(288)	(173)	(116)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1,484	1,487	1,490	1,493	1,495	1,500	1,503	1,506	1,509	1,511	1,515	1,518	
		Ending Balance	34,172,320	34,173,780	34,175,230	34,176,659	34,177,908	34,179,359	34,180,815	34,182,232	34,183,661	34,184,884	34,186,227	34,187,629	
	Change	Beginning Balance	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	(227,788)	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	**(227,788)**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 2 - FERC 311**														
		Plant													
		Beginning Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	336,834	
		Reserve													
	Original	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	-15.2%	
	Proposed	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	-15.1%	
	Original	Beginning Balance	347,153	348,861	350,569	352,276	353,983	355,690	357,397	359,104	360,810	362,515	364,221	365,926	
		Depr Expense	1,703	1,703	1,703	1,703	1,702	1,702	1,702	1,702	1,701	1,701	1,701	1,700	20,423
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	5	5	5	5	5	5	5	5	4	4	4	4	
		Ending Balance	348,861	350,569	352,276	353,983	355,690	357,397	359,104	360,810	362,515	364,221	365,926	367,631	
	Proposed	Beginning Balance	346,951	348,653	350,355	352,057	353,759	355,460	357,161	358,862	360,563	362,263	363,963	365,662	
		Depr Expense	1,698	1,697	1,697	1,697	1,697	1,696	1,696	1,696	1,696	1,695	1,695	1,695	20,356
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	5	5	5	5	5	5	5	5	4	4	4	4	
		Ending Balance	348,653	350,355	352,057	353,759	355,460	357,161	358,862	360,563	362,263	363,963	365,662	367,361	
	Change	Beginning Balance	(202)	(208)	(213)	(219)	(225)	(230)	(236)	(241)	(247)	(253)	(258)	(264)	
		Depr Expense	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(208)**	**(213)**	**(219)**	**(225)**	**(230)**	**(236)**	**(241)**	**(247)**	**(253)**	**(258)**	**(264)**	**(269)**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Steam	**Sherco 3**														
		Plant													
		Beginning Balance	801,887,027	801,903,080	801,904,898	801,908,385	801,915,387	801,947,459	801,955,241	801,964,006	801,983,413	802,109,097	802,467,741	802,805,144	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	16,053	1,818	3,487	7,002	32,072	7,782	8,766	19,406	125,684	358,644	337,402	100,991	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	801,903,080	801,904,898	801,908,385	801,915,387	801,947,459	801,955,241	801,964,006	801,983,413	802,109,097	802,467,741	802,805,144	802,906,135	
		Reserve													
	Original	Remaining Life (Mos)	132	131	130	129	128	127	126	125	124	123	122	121	
		Net Salvage Rate	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	-5.4%	
	Proposed	Remaining Life (Mos)	132	131	130	129	128	127	126	125	124	123	122	121	
		Net Salvage Rate	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	-7.9%	
	Original	Beginning Balance	596,667,676	598,538,569	600,421,384	602,304,151	604,186,829	606,068,690	607,951,792	609,834,979	611,718,059	613,601,807	615,486,509	617,361,310	
		Depr Expense	1,882,846	1,882,964	1,882,987	1,883,032	1,883,200	1,883,371	1,883,443	1,883,564	1,884,185	1,886,268	1,889,341	1,891,724	22,616,925
		Cost of Removal	(11,951)	(148)	(218)	(352)	(1,339)	(268)	(254)	(483)	(435)	(1,566)	(14,540)	(100,055)	
		Salvage	0	0	0	0	2	0	0	1	1	2	1	1	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	
		Ending Balance	598,538,569	600,421,384	602,304,151	604,186,829	606,068,690	607,951,792	609,834,979	611,718,059	613,601,807	615,486,509	617,361,310	619,152,978	
	Proposed	Beginning Balance	600,719,625	602,711,695	604,715,689	606,719,636	608,723,495	610,726,540	612,730,831	614,735,207	616,739,480	618,744,436	620,750,395	622,746,524	
		Depr Expense	2,004,024	2,004,143	2,004,167	2,004,213	2,004,384	2,004,560	2,004,633	2,004,757	2,005,392	2,007,525	2,010,669	2,013,097	24,071,564
		Cost of Removal	(11,951)	(148)	(218)	(352)	(1,339)	(268)	(254)	(483)	(435)	(1,566)	(14,540)	(100,055)	
		Salvage	0	0	0	0	2	0	0	1	1	2	1	1	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	
		Ending Balance	602,711,695	604,715,689	606,719,636	608,723,495	610,726,540	612,730,831	614,735,207	616,739,480	618,744,436	620,750,395	622,746,524	624,659,565	
	Change	Beginning Balance	4,051,948	4,173,126	4,294,305	4,415,485	4,536,666	4,657,850	4,779,038	4,900,229	5,021,421	5,142,629	5,263,886	5,385,214	
		Depr Expense	121,177	121,179	121,180	121,181	121,185	121,188	121,190	121,193	121,208	121,257	121,328	121,373	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**4,173,126**	**4,294,305**	**4,415,485**	**4,536,666**	**4,657,850**	**4,779,038**	**4,900,229**	**5,021,421**	**5,142,629**	**5,263,886**	**5,385,214**	**5,506,587**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Steam	Wilmarth														
		Plant													
		Beginning Balance	75,112,675	75,317,113	77,755,302	78,853,538	79,015,420	79,060,418	79,067,719	79,076,676	79,098,659	79,124,953	79,287,112	79,382,015	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	204,437	2,438,189	1,098,236	161,882	44,998	7,301	8,957	21,982	26,295	162,159	94,903	78,688	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	75,317,113	77,755,302	78,853,538	79,015,420	79,060,418	79,067,719	79,076,676	79,098,659	79,124,953	79,287,112	79,382,015	79,460,703	
		Reserve													
	Original	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	-26.8%	
	Proposed	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	-25.8%	
	Original	Beginning Balance	69,663,756	70,199,258	70,770,657	71,390,874	71,969,260	72,177,223	72,830,040	73,483,065	74,136,572	74,790,852	75,448,190	76,109,843	
		Depr Expense	535,600	571,246	619,983	638,401	647,054	652,932	653,181	653,663	654,432	657,499	661,792	664,906	7,610,689
		Cost of Removal	(4)	(3)	(5)	(60,008)	(439,031)	(6)	(6)	(11)	(10)	(37)	(22)	(10,015)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(94)	156	238	(6)	(60)	(109)	(149)	(145)	(141)	(125)	(117)	(123)	
		Ending Balance	70,199,258	70,770,657	71,390,874	71,969,260	72,177,223	72,830,040	73,483,065	74,136,572	74,790,852	75,448,190	76,109,843	76,764,610	
	Proposed	Beginning Balance	69,373,305	69,899,189	70,460,688	71,070,620	71,638,582	71,836,097	72,478,460	73,121,030	73,764,077	74,407,892	75,054,740	75,705,869	
		Depr Expense	525,981	561,346	609,699	627,977	636,606	642,478	642,725	643,203	643,966	647,010	651,269	654,359	7,486,619
		Cost of Removal	(4)	(3)	(5)	(60,008)	(439,031)	(6)	(6)	(11)	(10)	(37)	(22)	(10,015)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(94)	156	238	(6)	(60)	(109)	(149)	(145)	(141)	(125)	(117)	(123)	
		Ending Balance	69,899,189	70,460,688	71,070,620	71,638,582	71,836,097	72,478,460	73,121,030	73,764,077	74,407,892	75,054,740	75,705,869	76,350,089	
	Change	Beginning Balance	(290,451)	(300,070)	(309,969)	(320,254)	(330,678)	(341,126)	(351,580)	(362,035)	(372,495)	(382,960)	(393,450)	(403,974)	
		Depr Expense	(9,619)	(9,900)	(10,284)	(10,424)	(10,448)	(10,454)	(10,456)	(10,460)	(10,466)	(10,490)	(10,524)	(10,547)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(300,070)**	**(309,969)**	**(320,254)**	**(330,678)**	**(341,126)**	**(351,580)**	**(362,035)**	**(372,495)**	**(382,960)**	**(393,450)**	**(403,974)**	**(414,521)**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	Monticello														
		Plant													
		Beginning Balance	1,633,500,130	1,634,205,114	1,633,181,257	1,633,190,202	1,634,483,727	1,659,058,127	1,659,998,783	1,662,236,005	1,663,845,832	1,666,065,345	1,667,446,550	1,671,713,857	
		Retirements	-	(1,244,195)	-	(111,406)	-	-	-	-	-	-	-	-	
		Additions	704,984	220,338	8,945	1,404,931	24,574,401	940,656	2,237,222	1,609,827	2,219,513	1,381,205	4,267,307	1,933,270	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,634,205,114	1,633,181,257	1,633,190,202	1,634,483,727	1,659,058,127	1,659,998,783	1,662,236,005	1,663,845,832	1,666,065,345	1,667,446,550	1,671,713,857	1,673,647,128	
		Reserve													
	Original	Remaining Life (Mos)	117	116	115	114	113	112	111	110	109	108	107	106	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	117	116	115	114	113	112	111	110	109	108	107	106	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	872,502,532	879,009,728	884,140,079	890,653,519	896,992,929	903,628,132	910,377,242	917,077,396	923,708,188	929,723,034	936,290,413	942,946,911	
		Depr Expense	6,507,266	6,511,847	6,513,440	6,519,945	6,635,204	6,749,110	6,763,769	6,782,175	6,804,055	6,825,574	6,854,099	6,885,687	80,352,170
		Cost of Removal	(69)	(137,300)	-	(69,127)	-	-	(76,364)	(151,381)	(789,209)	(258,195)	(197,600)	(298,421)	
		Salvage	-	-	-	-	-	-	12,750	-	-	-	-	-	
		Retirements	-	(1,244,195)	-	(111,406)	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	879,009,728	884,140,079	890,653,519	896,992,929	903,628,132	910,377,242	917,077,396	923,708,188	929,723,034	936,290,413	942,946,911	949,534,176	
	Proposed	Beginning Balance	872,502,532	879,009,728	884,140,079	890,653,519	896,992,929	903,628,132	910,377,242	917,077,396	923,708,188	929,723,034	936,290,413	942,946,911	
		Depr Expense	6,507,266	6,511,847	6,513,440	6,519,945	6,635,204	6,749,110	6,763,769	6,782,175	6,804,055	6,825,574	6,854,099	6,885,687	80,352,170
		Cost of Removal	(69)	(137,300)	-	(69,127)	-	-	(76,364)	(151,381)	(789,209)	(258,195)	(197,600)	(298,421)	
		Salvage	-	-	-	-	-	-	12,750	-	-	-	-	-	
		Retirements	-	(1,244,195)	-	(111,406)	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	879,009,728	884,140,079	890,653,519	896,992,929	903,628,132	910,377,242	917,077,396	923,708,188	929,723,034	936,290,413	942,946,911	949,534,176	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Nuclear	**Prairie Island**														
		Plant													
		Beginning Balance	2,306,905,508	2,307,061,516	2,306,831,120	2,307,352,541	2,316,164,869	2,316,164,062	2,316,170,469	2,319,542,054	2,321,066,034	2,335,969,655	2,344,199,410	2,346,852,794	
		Retirements	-	(226,984)	-	-	-	-	-	-	-	-	-	-	
		Additions	156,008	(3,412)	521,421	8,812,328	(807)	6,406	3,371,586	1,523,980	14,903,621	8,229,755	2,653,384	9,018,943	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,307,061,516	2,306,831,120	2,307,352,541	2,316,164,869	2,316,164,062	2,316,170,469	2,319,542,054	2,321,066,034	2,335,969,655	2,344,199,410	2,346,852,794	2,355,871,738	
		Reserve													
	Original	Remaining Life (Mos)	160	159	158	157	156	155	154	153	152	151	150	149	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	160	159	158	157	156	155	154	153	152	151	150	149	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,200,799,782	1,207,713,512	1,214,348,457	1,221,264,539	1,228,210,365	1,235,184,451	1,242,158,536	1,248,834,610	1,254,318,452	1,261,381,770	1,268,525,499	1,275,663,598	
		Depr Expense	6,913,648	6,914,292	6,916,097	6,945,823	6,974,065	6,974,083	6,986,205	7,008,049	7,067,114	7,143,727	7,180,144	7,221,486	84,244,733
		Cost of Removal	78	(52,367)	(18)	-	18	-	(355,768)	(1,524,210)	(3,799)	-	(42,048)	(605,344)	
		Salvage	-	-	-	-	-	-	45,635	-	-	-	-	-	
		Retirements	-	(226,984)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	3	3	3	3	3	3	3	3	3	3	3	3	
		Ending Balance	1,207,713,512	1,214,348,457	1,221,264,539	1,228,210,365	1,235,184,451	1,242,158,536	1,248,834,610	1,254,318,452	1,261,381,770	1,268,525,499	1,275,663,598	1,282,279,742	
	Proposed	Beginning Balance	1,200,799,782	1,207,713,512	1,214,348,457	1,221,264,539	1,228,210,365	1,235,184,451	1,242,158,536	1,248,834,610	1,254,318,452	1,261,381,770	1,268,525,499	1,275,663,598	
		Depr Expense	6,913,648	6,914,292	6,916,097	6,945,823	6,974,065	6,974,083	6,986,205	7,008,049	7,067,114	7,143,727	7,180,144	7,221,486	84,244,733
		Cost of Removal	78	(52,367)	(18)	-	18	-	(355,768)	(1,524,210)	(3,799)	-	(42,048)	(605,344)	
		Salvage	-	-	-	-	-	-	45,635	-	-	-	-	-	
		Retirements	-	(226,984)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	3	3	3	3	3	3	3	3	3	3	3	3	
		Ending Balance	1,207,713,512	1,214,348,457	1,221,264,539	1,228,210,365	1,235,184,451	1,242,158,536	1,248,834,610	1,254,318,452	1,261,381,770	1,268,525,499	1,275,663,598	1,282,279,742	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	Monticello														
		Plant													
		Beginning Balance	1,673,647,128	1,673,653,128	1,673,980,657	1,673,989,657	1,673,992,657	1,684,063,506	1,684,963,506	1,686,297,863	1,686,732,334	1,686,733,427	1,686,951,800	1,687,182,984	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	6,000	327,529	9,000	3,000	10,070,849	900,000	1,334,357	434,471	1,093	218,372	231,184	7,217,487	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,673,653,128	1,673,980,657	1,673,989,657	1,673,992,657	1,684,063,506	1,684,963,506	1,686,297,863	1,686,732,334	1,686,733,427	1,686,951,800	1,687,182,984	1,694,400,471	
		Reserve													
	Original	Remaining Life (Mos)	105	104	103	102	101	100	99	98	97	96	95	94	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	105	104	103	102	101	100	99	98	97	96	95	94	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	949,534,176	956,430,518	963,328,464	969,891,197	976,794,137	981,193,358	988,226,559	995,271,044	1,002,324,554	1,008,940,579	1,016,002,058	1,023,065,903	
		Depr Expense	6,896,342	6,897,946	6,901,223	6,902,941	6,965,516	7,033,201	7,044,486	7,053,511	7,058,034	7,061,480	7,063,846	7,103,679	83,982,204
		Cost of Removal	-	-	(338,489)	-	(2,566,295)	-	-	-	(442,010)	-	-	(40,000)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	956,430,518	963,328,464	969,891,197	976,794,137	981,193,358	988,226,559	995,271,044	1,002,324,554	1,008,940,579	1,016,002,058	1,023,065,903	1,030,129,581	
	Proposed	Beginning Balance	949,534,176	956,430,518	963,328,464	969,891,197	976,794,137	981,193,358	988,226,559	995,271,044	1,002,324,554	1,008,940,579	1,016,002,058	1,023,065,903	
		Depr Expense	6,896,342	6,897,946	6,901,223	6,902,941	6,965,516	7,033,201	7,044,486	7,053,511	7,058,034	7,061,480	7,063,846	7,103,679	83,982,204
		Cost of Removal	-	-	(338,489)	-	(2,566,295)	-	-	-	(442,010)	-	-	(40,000)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	956,430,518	963,328,464	969,891,197	976,794,137	981,193,358	988,226,559	995,271,044	1,002,324,554	1,008,940,579	1,016,002,058	1,023,065,903	1,030,129,581	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	Prairie Island														
		Plant													
		Beginning Balance	2,355,871,738	2,355,924,517	2,357,485,452	2,357,946,262	2,358,306,262	2,358,631,299	2,358,747,549	2,382,670,340	2,385,765,416	2,389,738,737	2,397,583,036	2,407,710,507	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	52,779	1,560,935	460,810	360,000	325,036	116,250	23,922,791	3,095,076	3,973,321	7,844,299	10,127,471	13,018,783	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,355,924,517	2,357,485,452	2,357,946,262	2,358,306,262	2,358,631,299	2,358,747,549	2,382,670,340	2,385,765,416	2,389,738,737	2,397,583,036	2,407,710,507	2,420,729,290	
		Reserve													
	Original	Remaining Life (Mos)	148	147	146	145	144	143	142	141	140	139	138	137	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	148	147	146	145	144	143	142	141	140	139	138	137	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,282,279,742	1,289,533,923	1,296,540,968	1,303,809,292	1,310,763,936	1,318,039,666	1,325,316,940	1,332,653,946	1,340,106,866	1,347,590,049	1,355,115,741	1,362,704,555	
		Depr Expense	7,254,178	7,260,529	7,268,321	7,272,247	7,275,728	7,277,271	7,362,004	7,457,918	7,483,180	7,525,689	7,590,812	7,676,787	88,704,665
		Cost of Removal	-	(253,486)	-	(317,606)	-	-	(25,000)	(5,000)	-	-	(2,000)	(409,087)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	3	3	3	3	3	3	3	3	3	2	2	2	
		Ending Balance	1,289,533,923	1,296,540,968	1,303,809,292	1,310,763,936	1,318,039,666	1,325,316,940	1,332,653,946	1,340,106,866	1,347,590,049	1,355,115,741	1,362,704,555	1,369,972,258	
	Proposed	Beginning Balance	1,282,279,742	1,289,533,923	1,296,540,968	1,303,809,292	1,310,763,936	1,318,039,666	1,325,316,940	1,332,653,946	1,340,106,866	1,347,590,049	1,355,115,741	1,362,704,555	
		Depr Expense	7,254,178	7,260,529	7,268,321	7,272,247	7,275,728	7,277,271	7,362,004	7,457,918	7,483,180	7,525,689	7,590,812	7,676,787	88,704,665
		Cost of Removal	-	(253,486)	-	(317,606)	-	-	(25,000)	(5,000)	-	-	(2,000)	(409,087)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	3	3	3	3	3	3	3	3	3	2	2	2	
		Ending Balance	1,289,533,923	1,296,540,968	1,303,809,292	1,310,763,936	1,318,039,666	1,325,316,940	1,332,653,946	1,340,106,866	1,347,590,049	1,355,115,741	1,362,704,555	1,369,972,258	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2023												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	Monticello														
		Plant													
		Beginning Balance	1,694,400,471	1,694,403,264	1,694,405,127	1,696,942,377	1,697,028,091	1,726,097,596	1,730,110,302	1,730,334,319	1,731,007,501	1,732,004,651	1,732,492,781	1,732,658,552	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	2,793	1,863	2,537,250	85,714	29,069,505	4,012,706	224,017	673,182	997,150	488,130	165,771	9,411,033	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,694,403,264	1,694,405,127	1,696,942,377	1,697,028,091	1,726,097,596	1,730,110,302	1,730,334,319	1,731,007,501	1,732,004,651	1,732,492,781	1,732,658,552	1,742,069,585	
		Reserve													
	Original	Remaining Life (Mos)	93	92	91	90	89	88	87	86	85	84	83	82	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	93	92	91	90	89	88	87	86	85	84	83	82	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,030,129,581	1,037,272,293	1,044,298,866	1,051,456,831	1,058,629,368	1,065,965,699	1,073,489,997	1,081,018,758	1,088,089,967	1,094,825,923	1,102,342,344	1,109,935,516	
		Depr Expense	7,142,713	7,143,373	7,157,966	7,172,538	7,336,331	7,524,298	7,548,762	7,556,919	7,574,534	7,588,797	7,593,173	7,651,568	88,990,971
		Cost of Removal	-	(116,800)	-	-	-	-	(20,000)	(485,709)	(838,578)	(72,375)	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	1,037,272,293	1,044,298,866	1,051,456,831	1,058,629,368	1,065,965,699	1,073,489,997	1,081,018,758	1,088,089,967	1,094,825,923	1,102,342,344	1,109,935,516	1,117,587,083	
	Proposed	Beginning Balance	1,030,129,581	1,037,272,293	1,044,298,866	1,051,456,831	1,058,629,368	1,065,965,699	1,073,489,997	1,081,018,758	1,088,089,967	1,094,825,923	1,102,342,344	1,109,935,516	
		Depr Expense	7,142,713	7,143,373	7,157,966	7,172,538	7,336,331	7,524,298	7,548,762	7,556,919	7,574,534	7,588,797	7,593,173	7,651,568	88,990,971
		Cost of Removal	-	(116,800)	-	-	-	-	(20,000)	(485,709)	(838,578)	(72,375)	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	1,037,272,293	1,044,298,866	1,051,456,831	1,058,629,368	1,065,965,699	1,073,489,997	1,081,018,758	1,088,089,967	1,094,825,923	1,102,342,344	1,109,935,516	1,117,587,083	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		January 2023	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	Prairie Island														
		Plant													
		Beginning Balance	2,420,729,290	2,420,808,013	2,420,871,728	2,436,986,047	2,446,550,184	2,455,093,884	2,455,342,347	2,471,884,288	2,474,496,578	2,475,095,165	2,482,308,593	2,489,458,171	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	78,723	63,715	16,114,319	9,564,137	8,543,701	248,463	16,541,941	2,612,290	598,587	7,213,428	7,149,578	30,767,233	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,420,808,013	2,420,871,728	2,436,986,047	2,446,550,184	2,455,093,884	2,455,342,347	2,471,884,288	2,474,496,578	2,475,095,165	2,482,308,593	2,489,458,171	2,520,225,404	
		Reserve													
	Original	Remaining Life (Mos)	136	135	134	133	132	131	130	129	128	127	126	125	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	136	135	134	133	132	131	130	129	128	127	126	125	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,369,972,258	1,377,698,705	1,385,204,222	1,392,993,214	1,400,868,780	1,408,822,974	1,416,810,725	1,424,218,426	1,431,602,901	1,439,644,772	1,447,826,326	1,456,064,876	
		Depr Expense	7,726,444	7,727,795	7,788,990	7,885,563	7,954,191	7,987,749	8,054,817	8,134,473	8,150,369	8,181,552	8,238,548	8,393,875	96,224,366
		Cost of Removal	-	(222,280)	-	(10,000)	-	-	(647,117)	(750,000)	(108,501)	-	-	(915,000)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	2	2	2	2	2	2	2	2	2	2	2	2	
		Ending Balance	1,377,698,705	1,385,204,222	1,392,993,214	1,400,868,780	1,408,822,974	1,416,810,725	1,424,218,426	1,431,602,901	1,439,644,772	1,447,826,326	1,456,064,876	1,463,543,753	
	Proposed	Beginning Balance	1,369,972,258	1,377,698,705	1,385,204,222	1,392,993,214	1,400,868,780	1,408,822,974	1,416,810,725	1,424,218,426	1,431,602,901	1,439,644,772	1,447,826,326	1,456,064,876	
		Depr Expense	7,726,444	7,727,795	7,788,990	7,885,563	7,954,191	7,987,749	8,054,817	8,134,473	8,150,369	8,181,552	8,238,548	8,393,875	96,224,366
		Cost of Removal	-	(222,280)	-	(10,000)	-	-	(647,117)	(750,000)	(108,501)	-	-	(915,000)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	2	2	2	2	2	2	2	2	2	2	2	2	
		Ending Balance	1,377,698,705	1,385,204,222	1,392,993,214	1,400,868,780	1,408,822,974	1,416,810,725	1,424,218,426	1,431,602,901	1,439,644,772	1,447,826,326	1,456,064,876	1,463,543,753	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		January 2024	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	**Monticello**														
		Plant													
		Beginning Balance	1,742,069,585	1,742,074,406	1,742,075,410	1,743,041,253	1,743,065,121	1,743,083,021	1,743,307,235	1,743,491,062	1,743,491,562	1,743,492,062	1,743,924,599	1,743,966,885	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	4,820	1,004	965,843	23,868	17,900	224,214	183,827	500	500	432,537	42,286	7,404,013	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,742,074,406	1,742,075,410	1,743,041,253	1,743,065,121	1,743,083,021	1,743,307,235	1,743,491,062	1,743,491,562	1,743,492,062	1,743,924,599	1,743,966,885	1,751,370,898	
		Reserve													
	Original	Remaining Life (Mos)	81	80	79	78	77	76	75	74	73	72	71	70	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	81	80	79	78	77	76	75	74	73	72	71	70	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,117,587,083	1,125,296,773	1,132,997,322	1,140,713,284	1,148,435,590	1,156,158,167	1,163,882,337	1,171,599,294	1,179,327,564	1,187,050,875	1,194,782,228	1,202,516,924	
		Depr Expense	7,709,690	7,709,784	7,715,962	7,722,306	7,722,578	7,724,171	7,726,957	7,728,271	7,728,312	7,731,354	7,734,697	7,787,885	92,741,967
		Cost of Removal	-	(9,235)	-	-	-	-	(10,000)	-	(5,000)	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	1,125,296,773	1,132,997,322	1,140,713,284	1,148,435,590	1,156,158,167	1,163,882,337	1,171,599,294	1,179,327,564	1,187,050,875	1,194,782,228	1,202,516,924	1,210,304,809	
	Proposed	Beginning Balance	1,117,587,083	1,125,296,773	1,132,997,322	1,140,713,284	1,148,435,590	1,156,158,167	1,163,882,337	1,171,599,294	1,179,327,564	1,187,050,875	1,194,782,228	1,202,516,924	
		Depr Expense	7,709,690	7,709,784	7,715,962	7,722,306	7,722,578	7,724,171	7,726,957	7,728,271	7,728,312	7,731,354	7,734,697	7,787,885	92,741,967
		Cost of Removal	-	(9,235)	-	-	-	-	(10,000)	-	(5,000)	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	1,125,296,773	1,132,997,322	1,140,713,284	1,148,435,590	1,156,158,167	1,163,882,337	1,171,599,294	1,179,327,564	1,187,050,875	1,194,782,228	1,202,516,924	1,210,304,809	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name			January 2024	February	March	April	May	June	July	August	September	October	November	December	
Nuclear	**Prairie Island**															
			Plant													
			Beginning Balance	2,520,225,404	2,520,230,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,692,709	2,525,699,969	2,532,876,382	2,540,853,960	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Additions	5,000	5,000	-	-	-	-	-	457,305	5,007,260	7,176,413	7,977,578	25,886,514	
			Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
			Ending Balance	2,520,230,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,235,404	2,520,692,709	2,525,699,969	2,532,876,382	2,540,853,960	2,566,740,474	
			Reserve													
	Original		Remaining Life (Mos)	124	123	122	121	120	119	118	117	116	115	114	113	
			Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed		Remaining Life (Mos)	124	123	122	121	120	119	118	117	116	115	114	113	
			Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original		Beginning Balance	1,463,543,753	1,472,065,402	1,480,562,193	1,489,084,107	1,497,606,020	1,506,127,934	1,514,649,847	1,523,171,761	1,531,695,629	1,540,243,051	1,548,843,445	1,557,510,304	
			Depr Expense	8,521,646	8,521,789	8,521,912	8,521,912	8,521,912	8,521,912	8,521,911	8,523,866	8,547,420	8,600,392	8,666,857	8,819,808	102,811,336
			Cost of Removal	-	(25,000)	-	-	-	-	-	-	-	-	-	(702,804)	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	2	2	2	2	2	2	2	2	2	2	2	2	
			Ending Balance	1,472,065,402	1,480,562,193	1,489,084,107	1,497,606,020	1,506,127,934	1,514,649,847	1,523,171,761	1,531,695,629	1,540,243,051	1,548,843,445	1,557,510,304	1,565,627,311	
	Proposed		Beginning Balance	1,463,543,753	1,472,065,402	1,480,562,193	1,489,084,107	1,497,606,020	1,506,127,934	1,514,649,847	1,523,171,761	1,531,695,629	1,540,243,051	1,548,843,445	1,557,510,304	
			Depr Expense	8,521,646	8,521,789	8,521,912	8,521,912	8,521,912	8,521,912	8,521,911	8,523,866	8,547,420	8,600,392	8,666,857	8,819,808	102,811,336
			Cost of Removal	-	(25,000)	-	-	-	-	-	-	-	-	-	(702,804)	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	2	2	2	2	2	2	2	2	2	2	2	2	
			Ending Balance	1,472,065,402	1,480,562,193	1,489,084,107	1,497,606,020	1,506,127,934	1,514,649,847	1,523,171,761	1,531,695,629	1,540,243,051	1,548,843,445	1,557,510,304	1,565,627,311	
	Change		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
			Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
			Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	Hennepin Island														
		Plant													
		Beginning Balance	19,440,489	19,447,367	19,455,305	19,454,870	19,454,870	19,454,870	19,454,870	19,499,219	19,499,665	19,500,069	19,501,530	19,565,335	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	6,879	7,937	(435)	-	-	-	44,349	447	404	1,461	63,805	597	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,447,367	19,455,305	19,454,870	19,454,870	19,454,870	19,454,870	19,499,219	19,499,665	19,500,069	19,501,530	19,565,335	19,565,932	
		Reserve													
	Original	Remaining Life (Mos)	158	157	156	155	154	153	152	151	150	149	148	147	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	158	157	156	155	154	153	152	151	150	149	148	147	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	9,873,182	9,966,274	10,059,426	10,152,608	10,245,789	10,338,969	10,432,149	10,499,603	10,593,259	10,686,923	10,780,508	10,874,420	
		Depr Expense	93,063	93,122	93,153	93,151	93,150	93,150	93,420	93,693	93,697	93,706	93,985	94,296	1,121,586
		Cost of Removal	-	-	-	-	-	-	(25,965)	(37)	(34)	(121)	(73)	(10,049)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	29	30	30	30	30	30	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	9,966,274	10,059,426	10,152,608	10,245,789	10,338,969	10,432,149	10,499,603	10,593,259	10,686,923	10,780,508	10,874,420	10,958,667	
	Proposed	Beginning Balance	9,873,182	9,966,643	10,060,164	10,153,716	10,247,266	10,340,816	10,434,365	10,502,189	10,596,216	10,690,249	10,784,204	10,878,488	
		Depr Expense	93,432	93,492	93,522	93,520	93,520	93,520	93,790	94,064	94,068	94,076	94,356	94,668	1,126,026
		Cost of Removal	-	-	-	-	-	-	(25,965)	(37)	(34)	(121)	(73)	(10,049)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	29	30	30	30	30	30	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	9,966,643	10,060,164	10,153,716	10,247,266	10,340,816	10,434,365	10,502,189	10,596,216	10,690,249	10,784,204	10,878,488	10,963,107	
	Change	Beginning Balance	-	369	739	1,108	1,477	1,847	2,216	2,586	2,956	3,327	3,697	4,068	
		Depr Expense	369	369	369	369	369	369	370	370	370	370	371	372	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**369**	**739**	**1,108**	**1,477**	**1,847**	**2,216**	**2,586**	**2,956**	**3,327**	**3,697**	**4,068**	**4,439**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	Upper Dam														
		Plant													
		Beginning Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Reserve													
	Original	Remaining Life (Mos)	158	157	156	155	154	153	152	151	150	149	148	147	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	158	157	156	155	154	153	152	151	150	149	148	147	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	4,300,412	4,309,311	4,318,209	4,327,107	4,336,006	4,344,904	4,353,802	4,362,701	4,371,599	4,380,497	4,389,396	4,398,294	
		Depr Expense	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	106,781
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,309,311	4,318,209	4,327,107	4,336,006	4,344,904	4,353,802	4,362,701	4,371,599	4,380,497	4,389,396	4,398,294	4,407,192	
	Proposed	Beginning Balance	4,300,412	4,309,396	4,318,380	4,327,364	4,336,348	4,345,333	4,354,317	4,363,301	4,372,285	4,381,269	4,390,253	4,399,237	
		Depr Expense	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	107,809
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,309,396	4,318,380	4,327,364	4,336,348	4,345,333	4,354,317	4,363,301	4,372,285	4,381,269	4,390,253	4,399,237	4,408,221	
	Change	Beginning Balance	-	86	171	257	343	429	514	600	686	771	857	943	
		Depr Expense	86	86	86	86	86	86	86	86	86	86	86	86	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**86**	**171**	**257**	**343**	**429**	**514**	**600**	**686**	**771**	**857**	**943**	**1,029**	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Hydro	**St Croix Falls**														
		Plant													
		Beginning Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Reserve													
	Original	Remaining Life (Mos)	84	83	82	81	80	79	78	77	76	75	74	73	
		Net Salvage Rate	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	
	Proposed	Remaining Life (Mos)	84	83	82	81	80	79	78	77	76	75	74	73	
		Net Salvage Rate	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	
	Original	Beginning Balance	777,005	796,348	815,690	835,033	854,375	873,717	893,060	912,402	931,745	951,087	970,429	989,772	
		Depr Expense	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	232,109
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	0	-	-	-	-	-	-	-	
		Ending Balance	796,348	815,690	835,033	854,375	873,717	893,060	912,402	931,745	951,087	970,429	989,772	1,009,114	
	Proposed	Beginning Balance	777,005	798,343	819,680	841,017	862,354	883,691	905,029	926,366	947,703	969,040	990,378	1,011,715	
		Depr Expense	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	256,047
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	0	-	-	-	-	-	-	-	
		Ending Balance	798,343	819,680	841,017	862,354	883,691	905,029	926,366	947,703	969,040	990,378	1,011,715	1,033,052	
	Change	Beginning Balance	-	1,995	3,990	5,984	7,979	9,974	11,969	13,964	15,959	17,953	19,948	21,943	
		Depr Expense	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,995**	**3,990**	**5,984**	**7,979**	**9,974**	**11,969**	**13,964**	**15,959**	**17,953**	**19,948**	**21,943**	**23,938**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	Hennepin Island														
		Plant													
		Beginning Balance	19,565,932	19,565,946	19,565,961	19,565,982	19,566,017	19,566,149	19,566,176	19,566,201	19,566,250	19,583,098	19,587,423	19,591,686	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	15	14	21	35	132	27	25	49	16,848	4,325	4,262	65	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,565,946	19,565,961	19,565,982	19,566,017	19,566,149	19,566,176	19,566,201	19,566,250	19,583,098	19,587,423	19,591,686	19,591,750	
		Reserve													
	Original	Remaining Life (Mos)	146	145	144	143	142	141	140	139	138	137	136	135	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	146	145	144	143	142	141	140	139	138	137	136	135	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	10,958,667	11,052,999	11,147,332	11,241,664	11,335,995	11,430,319	11,524,652	11,618,986	11,713,318	11,807,728	11,902,227	11,996,770	
		Depr Expense	94,333	94,334	94,334	94,334	94,335	94,336	94,336	94,336	94,414	94,511	94,551	94,572	1,132,725
		Cost of Removal	(1)	(1)	(2)	(3)	(11)	(2)	(2)	(4)	(3)	(12)	(7)	(5)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	11,052,999	11,147,332	11,241,664	11,335,995	11,430,319	11,524,652	11,618,986	11,713,318	11,807,728	11,902,227	11,996,770	12,091,337	
	Proposed	Beginning Balance	10,963,107	11,057,810	11,152,514	11,247,218	11,341,921	11,436,616	11,531,321	11,626,027	11,720,730	11,815,512	11,910,383	12,005,299	
		Depr Expense	94,705	94,705	94,705	94,706	94,706	94,707	94,707	94,708	94,785	94,883	94,923	94,944	1,137,186
		Cost of Removal	(1)	(1)	(2)	(3)	(11)	(2)	(2)	(4)	(3)	(12)	(7)	(5)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	11,057,810	11,152,514	11,247,218	11,341,921	11,436,616	11,531,321	11,626,027	11,720,730	11,815,512	11,910,383	12,005,299	12,100,238	
	Change	Beginning Balance	4,439	4,811	5,183	5,554	5,926	6,298	6,669	7,041	7,413	7,784	8,156	8,529	
		Depr Expense	372	372	372	372	372	372	372	372	372	372	372	372	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**4,811**	**5,183**	**5,554**	**5,926**	**6,298**	**6,669**	**7,041**	**7,413**	**7,784**	**8,156**	**8,529**	**8,901**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	Upper Dam														
		Plant													
		Beginning Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Reserve													
	Original	Remaining Life (Mos)	146	145	144	143	142	141	140	139	138	137	136	135	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	146	145	144	143	142	141	140	139	138	137	136	135	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	4,407,192	4,416,091	4,424,989	4,433,887	4,442,786	4,451,684	4,460,582	4,469,481	4,478,379	4,487,277	4,496,176	4,505,074	
		Depr Expense	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	106,781
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,416,091	4,424,989	4,433,887	4,442,786	4,451,684	4,460,582	4,469,481	4,478,379	4,487,277	4,496,176	4,505,074	4,513,972	
	Proposed	Beginning Balance	4,408,221	4,417,205	4,426,189	4,435,173	4,444,157	4,453,141	4,462,125	4,471,109	4,480,093	4,489,077	4,498,061	4,507,046	
		Depr Expense	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	107,809
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,417,205	4,426,189	4,435,173	4,444,157	4,453,141	4,462,125	4,471,109	4,480,093	4,489,077	4,498,061	4,507,046	4,516,030	
	Change	Beginning Balance	1,029	1,114	1,200	1,286	1,371	1,457	1,543	1,629	1,714	1,800	1,886	1,972	
		Depr Expense	86	86	86	86	86	86	86	86	86	86	86	86	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,114**	**1,200**	**1,286**	**1,371**	**1,457**	**1,543**	**1,629**	**1,714**	**1,800**	**1,886**	**1,972**	**2,057**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Hydro	**St Croix Falls**														
		Plant													
		Beginning Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Reserve													
	Original	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	
	Proposed	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	
	Original	Beginning Balance	1,009,114	1,028,456	1,047,799	1,067,141	1,086,484	1,105,826	1,125,168	1,144,511	1,163,853	1,183,196	1,202,538	1,221,880	
		Depr Expense	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	232,109
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	-	(0)	0	-	(0)	0	-	-	
		Ending Balance	1,028,456	1,047,799	1,067,141	1,086,484	1,105,826	1,125,168	1,144,511	1,163,853	1,183,196	1,202,538	1,221,880	1,241,223	
	Proposed	Beginning Balance	1,033,052	1,054,389	1,075,726	1,097,064	1,118,401	1,139,738	1,161,075	1,182,412	1,203,750	1,225,087	1,246,424	1,267,761	
		Depr Expense	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	256,047
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	-	(0)	0	-	(0)	0	-	-	
		Ending Balance	1,054,389	1,075,726	1,097,064	1,118,401	1,139,738	1,161,075	1,182,412	1,203,750	1,225,087	1,246,424	1,267,761	1,289,098	
	Change	Beginning Balance	23,938	25,933	27,928	29,922	31,917	33,912	35,907	37,902	39,896	41,891	43,886	45,881	
		Depr Expense	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**25,933**	**27,928**	**29,922**	**31,917**	**33,912**	**35,907**	**37,902**	**39,896**	**41,891**	**43,886**	**45,881**	**47,876**	

Functional Class	Plant Name		January 2023	February	March	April	May	June	July	August	September	October	November	December	
Hydro	Hennepin Island														
		Plant													
		Beginning Balance	19,591,750	19,591,752	19,591,754	19,591,756	19,591,760	19,591,774	19,591,777	19,591,780	19,591,785	19,591,790	19,591,807	19,591,817	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	2	2	2	4	14	3	3	5	5	17	10	7	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,591,752	19,591,754	19,591,756	19,591,760	19,591,774	19,591,777	19,591,780	19,591,785	19,591,790	19,591,807	19,591,817	19,591,824	
		Reserve													
	Original	Remaining Life (Mos)	134	133	132	131	130	129	128	127	126	125	124	123	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	134	133	132	131	130	129	128	127	126	125	124	123	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	12,091,337	12,185,909	12,280,480	12,375,052	12,469,624	12,564,195	12,658,766	12,753,338	12,847,910	12,942,482	13,037,053	13,131,625	
		Depr Expense	94,572	94,572	94,572	94,572	94,572	94,572	94,572	94,572	94,572	94,572	94,573	94,573	1,134,866
		Cost of Removal	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	12,185,909	12,280,480	12,375,052	12,469,624	12,564,195	12,658,766	12,753,338	12,847,910	12,942,482	13,037,053	13,131,625	13,226,197	
	Proposed	Beginning Balance	12,100,238	12,195,182	12,290,125	12,385,069	12,480,013	12,574,956	12,669,900	12,764,844	12,859,788	12,954,732	13,049,676	13,144,620	
		Depr Expense	94,944	94,944	94,944	94,944	94,944	94,944	94,944	94,944	94,944	94,945	94,945	94,945	1,139,333
		Cost of Removal	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	12,195,182	12,290,125	12,385,069	12,480,013	12,574,956	12,669,900	12,764,844	12,859,788	12,954,732	13,049,676	13,144,620	13,239,564	
	Change	Beginning Balance	8,901	9,273	9,645	10,017	10,390	10,762	11,134	11,506	11,878	12,251	12,623	12,995	
		Depr Expense	372	372	372	372	372	372	372	372	372	372	372	372	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**9,273**	**9,645**	**10,017**	**10,390**	**10,762**	**11,134**	**11,506**	**11,878**	**12,251**	**12,623**	**12,995**	**13,367**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	Upper Dam														
		Plant													
		Beginning Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Reserve													
	Original	Remaining Life (Mos)	134	133	132	131	130	129	128	127	126	125	124	123	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	134	133	132	131	130	129	128	127	126	125	124	123	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	4,513,972	4,522,871	4,531,769	4,540,667	4,549,566	4,558,464	4,567,362	4,576,261	4,585,159	4,594,057	4,602,956	4,611,854	
		Depr Expense	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	106,781
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,522,871	4,531,769	4,540,667	4,549,566	4,558,464	4,567,362	4,576,261	4,585,159	4,594,057	4,602,956	4,611,854	4,620,753	
	Proposed	Beginning Balance	4,516,030	4,525,014	4,533,998	4,542,982	4,551,966	4,560,950	4,569,934	4,578,918	4,587,902	4,596,886	4,605,870	4,614,854	
		Depr Expense	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	107,809
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,525,014	4,533,998	4,542,982	4,551,966	4,560,950	4,569,934	4,578,918	4,587,902	4,596,886	4,605,870	4,614,854	4,623,838	
	Change	Beginning Balance	2,057	2,143	2,229	2,314	2,400	2,486	2,572	2,657	2,743	2,829	2,914	3,000	
		Depr Expense	86	86	86	86	86	86	86	86	86	86	86	86	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**2,143**	**2,229**	**2,314**	**2,400**	**2,486**	**2,572**	**2,657**	**2,743**	**2,829**	**2,914**	**3,000**	**3,086**	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Hydro	**St Croix Falls**														
		Plant													
		Beginning Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Reserve													
	Original	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	
	Proposed	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	
	Original	Beginning Balance	1,241,223	1,260,565	1,279,907	1,299,250	1,318,592	1,337,935	1,357,277	1,376,619	1,395,962	1,415,304	1,434,647	1,453,989	
		Depr Expense	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	232,109
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	0	(0)	0	(0)	(0)	0	(0)	0	
		Ending Balance	1,260,565	1,279,907	1,299,250	1,318,592	1,337,935	1,357,277	1,376,619	1,395,962	1,415,304	1,434,647	1,453,989	1,473,331	
	Proposed	Beginning Balance	1,289,098	1,310,436	1,331,773	1,353,110	1,374,447	1,395,785	1,417,122	1,438,459	1,459,796	1,481,133	1,502,471	1,523,808	
		Depr Expense	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	256,047
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	0	(0)	0	(0)	(0)	0	(0)	0	
		Ending Balance	1,310,436	1,331,773	1,353,110	1,374,447	1,395,785	1,417,122	1,438,459	1,459,796	1,481,133	1,502,471	1,523,808	1,545,145	
	Change	Beginning Balance	47,876	49,871	51,865	53,860	55,855	57,850	59,845	61,840	63,834	65,829	67,824	69,819	
		Depr Expense	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**49,871**	**51,865**	**53,860**	**55,855**	**57,850**	**59,845**	**61,840**	**63,834**	**65,829**	**67,824**	**69,819**	**71,814**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Hydro	**Hennepin Island**														
		Plant													
		Beginning Balance	19,591,824	19,591,824	19,591,825	19,591,825	19,591,825	19,591,827	19,591,827	19,591,827	19,591,828	19,591,828	19,591,830	19,591,831	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	0	0	0	0	2	0	0	1	1	2	1	1	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,591,824	19,591,825	19,591,825	19,591,825	19,591,827	19,591,827	19,591,827	19,591,828	19,591,828	19,591,830	19,591,831	19,591,832	
		Reserve													
	Original	Remaining Life (Mos)	122	121	120	119	118	117	116	115	114	113	112	111	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	122	121	120	119	118	117	116	115	114	113	112	111	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	13,226,197	13,320,769	13,415,342	13,509,915	13,604,487	13,699,060	13,793,632	13,888,205	13,982,778	14,077,350	14,171,923	14,266,495	
		Depr Expense	94,573	94,573	94,573	94,573	94,573	94,573	94,573	94,573	94,573	94,573	94,573	94,573	1,134,873
		Cost of Removal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	13,320,769	13,415,342	13,509,915	13,604,487	13,699,060	13,793,632	13,888,205	13,982,778	14,077,350	14,171,923	14,266,495	14,361,068	
	Proposed	Beginning Balance	13,239,564	13,334,509	13,429,453	13,524,398	13,619,343	13,714,288	13,809,233	13,904,177	13,999,122	14,094,067	14,189,012	14,283,957	
		Depr Expense	94,945	94,945	94,945	94,945	94,945	94,945	94,945	94,945	94,945	94,945	94,945	94,945	1,139,339
		Cost of Removal	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	13,334,509	13,429,453	13,524,398	13,619,343	13,714,288	13,809,233	13,904,177	13,999,122	14,094,067	14,189,012	14,283,957	14,378,902	
	Change	Beginning Balance	13,367	13,739	14,112	14,484	14,856	15,228	15,600	15,972	16,345	16,717	17,089	17,461	
		Depr Expense	372	372	372	372	372	372	372	372	372	372	372	372	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**13,739**	**14,112**	**14,484**	**14,856**	**15,228**	**15,600**	**15,972**	**16,345**	**16,717**	**17,089**	**17,461**	**17,833**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	**Upper Dam**														
		Plant													
		Beginning Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	4,514,522	
		Reserve													
	Original	Remaining Life (Mos)	122	121	120	119	118	117	116	115	114	113	112	111	
		Net Salvage Rate	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	-26.4%	
	Proposed	Remaining Life (Mos)	122	121	120	119	118	117	116	115	114	113	112	111	
		Net Salvage Rate	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	-26.7%	
	Original	Beginning Balance	4,620,753	4,629,651	4,638,549	4,647,448	4,656,346	4,665,244	4,674,143	4,683,041	4,691,939	4,700,838	4,709,736	4,718,634	
		Depr Expense	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	8,898	106,781
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,629,651	4,638,549	4,647,448	4,656,346	4,665,244	4,674,143	4,683,041	4,691,939	4,700,838	4,709,736	4,718,634	4,727,533	
	Proposed	Beginning Balance	4,623,838	4,632,822	4,641,806	4,650,791	4,659,775	4,668,759	4,677,743	4,686,727	4,695,711	4,704,695	4,713,679	4,722,663	
		Depr Expense	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	8,984	107,809
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	4,632,822	4,641,806	4,650,791	4,659,775	4,668,759	4,677,743	4,686,727	4,695,711	4,704,695	4,713,679	4,722,663	4,731,647	
	Change	Beginning Balance	3,086	3,172	3,257	3,343	3,429	3,514	3,600	3,686	3,772	3,857	3,943	4,029	
		Depr Expense	86	86	86	86	86	86	86	86	86	86	86	86	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**3,172**	**3,257**	**3,343**	**3,429**	**3,514**	**3,600**	**3,686**	**3,772**	**3,857**	**3,943**	**4,029**	**4,114**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Hydro	St Croix Falls														
		Plant													
		Beginning Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	2,234,201	
		Reserve													
	Original	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	-7.5%	
	Proposed	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	-15.0%	
	Original	Beginning Balance	1,473,331	1,492,674	1,512,016	1,531,358	1,550,701	1,570,043	1,589,386	1,608,728	1,628,070	1,647,413	1,666,755	1,686,098	
		Depr Expense	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	19,342	232,109
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	-	0	(0)	-	0	(0)	(0)	
		Ending Balance	1,492,674	1,512,016	1,531,358	1,550,701	1,570,043	1,589,386	1,608,728	1,628,070	1,647,413	1,666,755	1,686,098	1,705,440	
	Proposed	Beginning Balance	1,545,145	1,566,482	1,587,819	1,609,157	1,630,494	1,651,831	1,673,168	1,694,505	1,715,843	1,737,180	1,758,517	1,779,854	
		Depr Expense	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	21,337	256,046
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	-	0	(0)	-	0	(0)	(0)	
		Ending Balance	1,566,482	1,587,819	1,609,157	1,630,494	1,651,831	1,673,168	1,694,505	1,715,843	1,737,180	1,758,517	1,779,854	1,801,191	
	Change	Beginning Balance	71,814	73,809	75,803	77,798	79,793	81,788	83,783	85,777	87,772	89,767	91,762	93,757	
		Depr Expense	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	1,995	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**73,809**	**75,803**	**77,798**	**79,793**	**81,788**	**83,783**	**85,777**	**87,772**	**89,767**	**91,762**	**93,757**	**95,752**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 2 & 3														
		Plant													
		Beginning Balance	87,225,286	87,225,286	84,578,118	84,650,212	85,883,196	85,881,648	85,995,323	86,210,522	86,228,051	86,271,996	86,822,858	86,978,195	
		Retirements	-	(2,647,167)	-	-	(26,021)	-	-	-	-	-	-	-	
		Additions	-	-	72,094	1,232,984	24,473	113,675	215,199	17,529	43,945	550,861	155,338	175,204	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	87,225,286	84,578,118	84,650,212	85,883,196	85,881,648	85,995,323	86,210,522	86,228,051	86,271,996	86,822,858	86,978,195	87,153,399	
		Reserve													
	Original	Remaining Life (Mos)	240	239	238	237	236	235	234	233	232	231	230	229	
		Net Salvage Rate	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	
	Proposed	Remaining Life (Mos)	240	239	238	237	236	235	234	233	232	231	230	229	
		Net Salvage Rate	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	
	Original	Beginning Balance	71,125,151	71,227,121	67,667,175	67,772,552	67,880,964	67,963,018	68,074,618	68,186,299	68,297,872	68,409,731	68,420,090	68,534,114	
		Depr Expense	101,974	104,101	105,336	108,353	111,280	111,598	112,370	112,922	113,072	114,712	116,627	117,512	1,329,857
		Cost of Removal	-	(1,016,937)	-	-	(3,260)	-	(709)	(1,346)	(1,212)	(104,406)	(2,617)	(40,422)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(2,647,167)	-	-	(26,021)	-	-	-	-	-	-	-	
		Transfers/Adjustments	(4)	57	41	58	56	2	21	(3)	(1)	52	15	13	
		Ending Balance	71,227,121	67,667,175	67,772,552	67,880,964	67,963,018	68,074,618	68,186,299	68,297,872	68,409,731	68,420,090	68,534,114	68,611,217	
	Proposed	Beginning Balance	71,125,151	71,232,936	67,678,805	67,789,821	67,903,917	67,991,697	68,109,026	68,226,448	68,343,769	68,461,379	68,477,508	68,597,328	
		Depr Expense	107,789	109,916	110,975	114,037	117,006	117,327	118,110	118,670	118,823	120,483	122,423	123,319	1,398,878
		Cost of Removal	-	(1,016,937)	-	-	(3,260)	-	(709)	(1,346)	(1,212)	(104,406)	(2,617)	(40,422)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(2,647,167)	-	-	(26,021)	-	-	-	-	-	-	-	
		Transfers/Adjustments	(4)	57	41	58	56	2	21	(3)	(1)	52	15	13	
		Ending Balance	71,232,936	67,678,805	67,789,821	67,903,917	67,991,697	68,109,026	68,226,448	68,343,769	68,461,379	68,477,508	68,597,328	68,680,238	
	Change	Beginning Balance	-	5,815	11,630	17,270	22,953	28,679	34,408	40,149	45,897	51,647	57,418	63,214	
		Depr Expense	5,815	5,815	5,639	5,684	5,726	5,729	5,740	5,748	5,750	5,771	5,796	5,807	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**5,815**	**11,630**	**17,270**	**22,953**	**28,679**	**34,408**	**40,149**	**45,897**	**51,647**	**57,418**	**63,214**	**69,021**	
Other	Angus Anson Unit 2 & 3 - FERC 341														
		Plant													
		Beginning Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Reserve													
	Original	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	5,575,085	5,583,735	5,592,385	5,601,034	5,609,684	5,618,334	5,626,984	5,635,634	5,644,284	5,652,934	5,661,583	5,670,233	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,583,735	5,592,385	5,601,034	5,609,684	5,618,334	5,626,984	5,635,634	5,644,284	5,652,934	5,661,583	5,670,233	5,678,883	
	Proposed	Beginning Balance	5,575,085	5,583,735	5,592,385	5,601,034	5,609,684	5,618,334	5,626,984	5,635,634	5,644,284	5,652,934	5,661,583	5,670,233	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,583,735	5,592,385	5,601,034	5,609,684	5,618,334	5,626,984	5,635,634	5,644,284	5,652,934	5,661,583	5,670,233	5,678,883	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 4														
		Plant													
		Beginning Balance	38,642,199	38,642,199	38,642,199	38,642,205	38,647,092	38,661,813	38,682,684	38,682,684	38,682,684	38,682,684	38,819,680	38,839,680	
		Retirements	-	-	-	(2,793)	-	-	-	-	-	-	-	-	
		Additions	-	-	6	7,680	14,721	20,871	-	-	-	136,996	20,000	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	38,642,199	38,642,199	38,642,205	38,647,092	38,661,813	38,682,684	38,682,684	38,682,684	38,682,684	38,819,680	38,839,680	38,839,680	
		Reserve													
	Original	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	17,935,922	18,015,166	18,094,409	18,173,653	18,248,823	18,328,126	18,407,495	18,486,902	18,566,310	18,645,717	18,725,381	18,805,341	
		Depr Expense	79,242	79,242	79,242	79,259	79,302	79,367	79,406	79,406	79,406	79,663	79,958	79,999	953,494
		Cost of Removal	-	-	-	(1,298)	-	-	-	-	-	-	-	(1,739)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	(2,793)	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	18,015,166	18,094,409	18,173,653	18,248,823	18,328,126	18,407,495	18,486,902	18,566,310	18,645,717	18,725,381	18,805,341	18,883,603	
	Proposed	Beginning Balance	17,935,922	18,015,166	18,094,409	18,173,653	18,248,823	18,328,126	18,407,495	18,486,902	18,566,310	18,645,717	18,725,381	18,805,341	
		Depr Expense	79,242	79,242	79,242	79,259	79,302	79,367	79,406	79,406	79,406	79,663	79,958	79,999	953,494
		Cost of Removal	-	-	-	(1,298)	-	-	-	-	-	-	-	(1,739)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	(2,793)	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	18,015,166	18,094,409	18,173,653	18,248,823	18,328,126	18,407,495	18,486,902	18,566,310	18,645,717	18,725,381	18,805,341	18,883,603	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Black Dog Unit 5														
		Plant													
		Beginning Balance	195,055,640	195,345,698	195,417,212	195,422,349	195,422,325	195,431,961	195,431,961	195,500,833	195,525,897	195,582,810	197,015,291	197,665,748	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	290,058	71,514	5,138	(24)	9,637	-	68,872	25,064	56,913	1,432,481	650,458	1,323,837	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	195,345,698	195,417,212	195,422,349	195,422,325	195,431,961	195,431,961	195,500,833	195,525,897	195,582,810	197,015,291	197,665,748	198,989,585	
		Reserve													
	Original	Remaining Life (Mos)	132	131	130	129	128	127	126	125	124	123	122	121	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	132	131	130	129	128	127	126	125	124	123	122	121	
		Net Salvage Rate	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	
	Original	Beginning Balance	105,218,552	106,068,818	106,920,620	107,772,751	108,624,904	109,477,099	110,329,336	110,984,352	111,835,568	112,687,512	113,528,171	114,393,097	
		Depr Expense	850,265	851,802	852,131	852,153	852,195	852,237	853,328	854,554	854,947	861,790	871,413	881,081	10,287,897
		Cost of Removal	-	-	-	-	-	-	(198,314)	(3,337)	(3,004)	(21,131)	(6,488)	(133,687)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	1	0	0	0	0	1	
		Ending Balance	106,068,818	106,920,620	107,772,751	108,624,904	109,477,099	110,329,336	110,984,352	111,835,568	112,687,512	113,528,171	114,393,097	115,140,492	
	Proposed	Beginning Balance	105,218,552	106,006,708	106,796,344	107,586,295	108,376,268	109,166,280	109,956,334	110,549,154	111,338,160	112,127,879	112,906,059	113,708,147	
		Depr Expense	788,156	789,635	789,951	789,972	790,013	790,053	791,133	792,343	792,723	799,311	808,576	817,900	9,539,767
		Cost of Removal	-	-	-	-	-	-	(198,314)	(3,337)	(3,004)	(21,131)	(6,488)	(133,687)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	1	0	0	0	0	1	
		Ending Balance	106,006,708	106,796,344	107,586,295	108,376,268	109,166,280	109,956,334	110,549,154	111,338,160	112,127,879	112,906,059	113,708,147	114,392,361	
	Change	Beginning Balance	-	(62,109)	(124,277)	(186,456)	(248,637)	(310,819)	(373,002)	(435,198)	(497,408)	(559,633)	(622,112)	(684,950)	
		Depr Expense	(62,109)	(62,167)	(62,180)	(62,180)	(62,182)	(62,184)	(62,195)	(62,211)	(62,225)	(62,479)	(62,838)	(63,180)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(62,109)**	**(124,277)**	**(186,456)**	**(248,637)**	**(310,819)**	**(373,002)**	**(435,198)**	**(497,408)**	**(559,633)**	**(622,112)**	**(684,950)**	**(748,130)**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Black Dog Unit 5 FERC 341														
		Plant													
		Beginning Balance	43,246,586	43,246,586	43,246,586	43,246,586	43,246,586	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Retirements	-	-	-	-	(8,038)	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	43,246,586	43,246,586	43,246,586	43,246,586	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Reserve													
	Original	Remaining Life (Mos)	447	446	445	444	443	442	441	440	439	438	437	436	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	447	446	445	444	443	442	441	440	439	438	437	436	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	27,476,027	27,522,345	27,568,662	27,614,980	27,661,297	27,697,585	27,743,905	27,790,225	27,836,544	27,882,864	27,929,184	27,975,503	
		Depr Expense	46,310	46,310	46,310	46,310	46,312	46,313	46,313	46,313	46,313	46,313	46,312	46,312	555,741
		Cost of Removal	-	-	-	-	(1,994)	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(8,038)	-	-	-	-	-	-	-	
		Transfers/Adjustments	7	7	7	7	7	7	7	7	7	7	7	7	
		Ending Balance	27,522,345	27,568,662	27,614,980	27,661,297	27,697,585	27,743,905	27,790,225	27,836,544	27,882,864	27,929,184	27,975,503	28,021,823	
	Proposed	Beginning Balance	27,476,027	27,521,281	27,566,534	27,611,787	27,657,041	27,692,264	27,737,520	27,782,775	27,828,031	27,873,287	27,918,542	27,963,798	
		Depr Expense	45,246	45,246	45,246	45,246	45,248	45,249	45,249	45,249	45,248	45,248	45,248	45,248	542,971
		Cost of Removal	-	-	-	-	(1,994)	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(8,038)	-	-	-	-	-	-	-	
		Transfers/Adjustments	7	7	7	7	7	7	7	7	7	7	7	7	
		Ending Balance	27,521,281	27,566,534	27,611,787	27,657,041	27,692,264	27,737,520	27,782,775	27,828,031	27,873,287	27,918,542	27,963,798	28,009,053	
	Change	Beginning Balance	-	(1,064)	(2,128)	(3,193)	(4,257)	(5,321)	(6,385)	(7,449)	(8,513)	(9,577)	(10,641)	(11,705)	
		Depr Expense	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(1,064)**	**(2,128)**	**(3,193)**	**(4,257)**	**(5,321)**	**(6,385)**	**(7,449)**	**(8,513)**	**(9,577)**	**(10,641)**	**(11,705)**	**(12,769)**	
Other	Black Dog Unit 6														
		Plant													
		Beginning Balance	102,402,794	102,404,720	102,405,201	102,405,216	102,405,216	102,405,217	102,405,217	102,405,217	102,405,217	102,405,217	102,593,807	102,674,665	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	1,926	481	15	-	0	-	-	-	-	188,590	80,858	7,500	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	102,404,720	102,405,201	102,405,216	102,405,216	102,405,217	102,405,217	102,405,217	102,405,217	102,405,217	102,593,807	102,674,665	102,682,165	
		Reserve													
	Original	Remaining Life (Mos)	447	446	445	444	443	442	441	440	439	438	437	436	
		Net Salvage Rate	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	
	Proposed	Remaining Life (Mos)	447	446	445	444	443	442	441	440	439	438	437	436	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	15,973,755	16,178,565	16,383,378	16,588,192	16,793,005	16,997,819	17,202,632	17,388,324	17,593,181	17,798,038	18,003,121	18,208,528	
		Depr Expense	204,810	204,813	204,814	204,814	204,814	204,814	204,835	204,857	204,857	205,083	205,407	205,513	2,459,431
		Cost of Removal	-	-	-	-	-	-	(19,144)	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	16,178,565	16,383,378	16,588,192	16,793,005	16,997,819	17,202,632	17,388,324	17,593,181	17,798,038	18,003,121	18,208,528	18,414,041	
	Proposed	Beginning Balance	15,973,755	16,190,707	16,407,662	16,624,618	16,841,573	17,058,529	17,275,484	17,473,317	17,690,316	17,907,315	18,124,552	18,342,128	
		Depr Expense	216,952	216,955	216,956	216,956	216,956	216,956	216,977	216,999	216,999	217,237	217,577	217,688	2,605,208
		Cost of Removal	-	-	-	-	-	-	(19,144)	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	16,190,707	16,407,662	16,624,618	16,841,573	17,058,529	17,275,484	17,473,317	17,690,316	17,907,315	18,124,552	18,342,128	18,559,817	
	Change	Beginning Balance	-	12,142	24,284	36,426	48,568	60,710	72,852	84,994	97,136	109,278	121,431	133,601	
		Depr Expense	12,142	12,142	12,142	12,142	12,142	12,142	12,142	12,142	12,142	12,153	12,170	12,175	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**12,142**	**24,284**	**36,426**	**48,568**	**60,710**	**72,852**	**84,994**	**97,136**	**109,278**	**121,431**	**133,601**	**145,776**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blazing Star I WF														
		Plant													
		Beginning Balance	306,469,567	306,480,262	306,515,673	306,664,993	306,998,946	307,036,912	307,160,028	307,190,028	307,195,028	307,927,027	307,962,957	307,963,457	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	10,695	35,411	149,319	333,954	37,966	123,116	30,000	5,000	732,000	35,930	500	227,224	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	306,480,262	306,515,673	306,664,993	306,998,946	307,036,912	307,160,028	307,190,028	307,195,028	307,927,027	307,962,957	307,963,457	308,190,681	
		Reserve													
	Original	Remaining Life (Mos)	292	291	290	289	288	287	286	285	284	283	282	281	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	292	291	290	289	288	287	286	285	284	283	282	281	
		Net Salvage Rate	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	
	Original	Beginning Balance	9,377,044	10,483,716	11,590,474	12,697,578	13,805,589	14,914,300	16,023,316	17,132,622	18,241,995	19,352,776	20,465,029	21,574,156	
		Depr Expense	1,106,672	1,106,758	1,107,104	1,108,011	1,108,711	1,109,016	1,109,306	1,109,373	1,110,781	1,112,253	1,112,323	1,112,774	13,313,081
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(33)	
		Salvage	-	-	-	-	-	-	-	-	-	-	(3,195)	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	(0)	-	-	-	-	-	0	(0)	0	(0)	
		Ending Balance	10,483,716	11,590,474	12,697,578	13,805,589	14,914,300	16,023,316	17,132,622	18,241,995	19,352,776	20,465,029	21,574,156	22,686,898	
	Proposed	Beginning Balance	9,377,044	10,516,253	11,655,550	12,795,203	13,935,789	15,077,095	16,218,714	17,360,633	18,502,619	19,646,054	20,791,003	21,932,829	
		Depr Expense	1,139,209	1,139,297	1,139,653	1,140,586	1,141,306	1,141,620	1,141,918	1,141,987	1,143,435	1,144,949	1,145,021	1,145,485	13,704,465
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(33)	
		Salvage	-	-	-	-	-	-	-	-	-	-	(3,195)	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	(0)	-	-	-	-	-	0	(0)	0	(0)	
		Ending Balance	10,516,253	11,655,550	12,795,203	13,935,789	15,077,095	16,218,714	17,360,633	18,502,619	19,646,054	20,791,003	21,932,829	23,078,281	
	Change	Beginning Balance	-	32,537	65,076	97,625	130,200	162,795	195,399	228,011	260,624	293,279	325,975	358,673	
		Depr Expense	32,537	32,539	32,549	32,575	32,595	32,604	32,612	32,614	32,654	32,696	32,698	32,711	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**32,537**	**65,076**	**97,625**	**130,200**	**162,795**	**195,399**	**228,011**	**260,624**	**293,279**	**325,975**	**358,673**	**391,384**	
Other	Blazing Star II WF														
		Plant													
		Beginning Balance	-	327,585,821	334,753,567	335,365,491	334,683,517	335,230,471	335,963,724	336,462,858	337,402,571	337,859,314	338,590,480	338,605,000	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	327,585,821	7,167,746	611,924	(681,975)	546,955	733,253	499,134	939,713	456,743	731,166	14,520	140,018	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	327,585,821	334,753,567	335,365,491	334,683,517	335,230,471	335,963,724	336,462,858	337,402,571	337,859,314	338,590,480	338,605,000	338,745,018	
		Reserve													
	Original	Remaining Life (Mos)	301	300	299	298	297	296	295	294	293	292	291	290	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	301	300	299	298	297	296	295	294	293	292	291	290	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	-	601,300	1,819,104	3,051,283	4,283,333	5,515,131	6,749,319	7,985,815	9,225,016	10,466,849	11,710,930	12,956,427	
		Depr Expense	601,300	1,217,804	1,232,180	1,232,050	1,231,798	1,234,188	1,236,496	1,239,200	1,241,833	1,244,081	1,245,497	1,245,791	14,202,218
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	1	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	(24,991)	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	0	(0)	-	0	0	(0)	-	-	-	-	
		Ending Balance	601,300	1,819,104	3,051,283	4,283,333	5,515,131	6,749,319	7,985,815	9,225,016	10,466,849	11,710,930	12,956,427	14,177,227	
	Proposed	Beginning Balance	-	601,300	1,819,104	3,051,283	4,283,333	5,515,131	6,749,319	7,985,815	9,225,016	10,466,849	11,710,930	12,956,427	
		Depr Expense	601,300	1,217,804	1,232,180	1,232,050	1,231,798	1,234,188	1,236,496	1,239,200	1,241,833	1,244,081	1,245,497	1,245,791	14,202,218
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	1	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	(24,991)	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	0	(0)	-	0	0	(0)	-	-	-	-	
		Ending Balance	601,300	1,819,104	3,051,283	4,283,333	5,515,131	6,749,319	7,985,815	9,225,016	10,466,849	11,710,930	12,956,427	14,177,227	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 1 thru 4														
		Plant													
		Beginning Balance	24,614,220	24,614,225	24,614,225	24,662,919	24,664,310	24,658,209	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	
		Retirements	-	-	-	-	(6,101)	-	-	-	-	-	-	-	
		Additions	5	-	48,694	1,391	-	177	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	24,614,225	24,614,225	24,662,919	24,664,310	24,658,209	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	
		Reserve													
	Original	Remaining Life (Mos)	30	29	28	27	26	25	24	23	22	21	20	19	
		Net Salvage Rate	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	
	Proposed	Remaining Life (Mos)	30	29	28	27	26	25	24	23	22	21	20	19	
		Net Salvage Rate	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	
	Original	Beginning Balance	29,806,681	29,821,488	29,836,295	29,852,171	29,869,185	29,876,438	29,893,583	29,910,732	29,927,882	29,945,031	29,962,180	29,979,330	
		Depr Expense	14,807	14,807	15,875	17,015	17,121	17,144	17,149	17,149	17,149	17,149	17,149	17,149	199,662
		Cost of Removal	-	-	-	-	(3,767)	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(6,101)	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	(0)	(0)	0	0	0	0	0	0	0	0	
		Ending Balance	29,821,488	29,836,295	29,852,171	29,869,185	29,876,438	29,893,583	29,910,732	29,927,882	29,945,031	29,962,180	29,979,330	29,996,479	
	Proposed	Beginning Balance	29,806,681	29,884,665	29,962,648	30,041,767	30,122,097	30,192,667	30,273,110	30,353,558	30,434,006	30,514,454	30,594,902	30,675,350	
		Depr Expense	77,983	77,983	79,119	80,330	80,438	80,443	80,448	80,448	80,448	80,448	80,448	80,448	958,981
		Cost of Removal	-	-	-	-	(3,767)	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(6,101)	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	(0)	(0)	0	0	0	0	0	0	0	0	
		Ending Balance	29,884,665	29,962,648	30,041,767	30,122,097	30,192,667	30,273,110	30,353,558	30,434,006	30,514,454	30,594,902	30,675,350	30,755,798	
	Change	Beginning Balance	-	63,177	126,353	189,596	252,911	316,228	379,527	442,825	506,124	569,423	632,722	696,020	
		Depr Expense	63,177	63,177	63,243	63,315	63,317	63,298	63,299	63,299	63,299	63,299	63,299	63,299	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**63,177**	**126,353**	**189,596**	**252,911**	**316,228**	**379,527**	**442,825**	**506,124**	**569,423**	**632,722**	**696,020**	**759,319**	
Other	Blue Lake Units 1 thru 4 - FERC 341														
		Plant													
		Beginning Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Reserve													
	Original	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	1,088,521	1,089,204	1,089,887	1,090,571	1,091,254	1,091,937	1,092,620	1,093,303	1,093,987	1,094,670	1,095,353	1,096,036	
		Depr Expense	683	683	683	683	683	683	683	683	683	683	683	683	8,199
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	0	-	(0)	-	-	(0)	-	0	(0)	-	
		Ending Balance	1,089,204	1,089,887	1,090,571	1,091,254	1,091,937	1,092,620	1,093,303	1,093,987	1,094,670	1,095,353	1,096,036	1,096,720	
	Proposed	Beginning Balance	1,088,521	1,089,243	1,089,966	1,090,689	1,091,411	1,092,134	1,092,856	1,093,579	1,094,302	1,095,024	1,095,747	1,096,469	
		Depr Expense	723	723	723	723	723	723	723	723	723	723	723	723	8,671
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	0	-	(0)	-	-	(0)	-	0	(0)	-	
		Ending Balance	1,089,243	1,089,966	1,090,689	1,091,411	1,092,134	1,092,856	1,093,579	1,094,302	1,095,024	1,095,747	1,096,469	1,097,192	
	Change	Beginning Balance	-	39	79	118	158	197	236	276	315	354	394	433	
		Depr Expense	39	39	39	39	39	39	39	39	39	39	39	39	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**39**	**79**	**118**	**158**	**197**	**236**	**276**	**315**	**354**	**394**	**433**	**473**	

Functional Class	Plant Name		2021 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 7 & 8														
		Plant													
		Beginning Balance	71,535,883	71,554,486	71,560,358	72,308,578	72,310,332	72,240,876	72,241,148	72,241,508	72,243,951	72,549,190	76,164,418	76,475,137	
		Retirements	-	-	-	-	(1,519)	-	-	-	-	-	-	-	
		Additions	18,603	5,872	748,219	1,755	(67,937)	272	360	2,443	305,240	3,615,228	310,719	204,081	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	71,554,486	71,560,358	72,308,578	72,310,332	72,240,876	72,241,148	72,241,508	72,243,951	72,549,190	76,164,418	76,475,137	76,679,218	
		Reserve													
	Original	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	35,605,094	35,756,326	35,907,606	36,060,332	36,214,503	36,366,558	36,520,471	36,660,732	36,813,904	36,967,762	37,127,472	37,295,969	
		Depr Expense	151,232	151,278	152,726	154,170	154,043	153,912	153,937	153,968	154,573	162,289	170,044	171,194	1,883,366
		Cost of Removal	-	-	-	-	(470)	-	(13,676)	(796)	(717)	(2,580)	(1,548)	(71,755)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(1,519)	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	35,756,326	35,907,606	36,060,332	36,214,503	36,366,558	36,520,471	36,660,732	36,813,904	36,967,762	37,127,472	37,295,969	37,395,408	
	Proposed	Beginning Balance	35,605,094	35,758,768	35,912,490	36,067,671	36,224,310	36,378,832	36,535,211	36,677,938	36,833,576	36,989,905	37,152,155	37,323,262	
		Depr Expense	153,673	153,721	155,181	156,638	156,510	156,378	156,403	156,434	157,045	164,829	172,654	173,812	1,913,277
		Cost of Removal	-	-	-	-	(470)	-	(13,676)	(796)	(717)	(2,580)	(1,548)	(71,755)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	(1,519)	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	35,758,768	35,912,490	36,067,671	36,224,310	36,378,832	36,535,211	36,677,938	36,833,576	36,989,905	37,152,155	37,323,262	37,425,319	
	Change	Beginning Balance	-	2,442	4,884	7,339	9,807	12,274	14,740	17,206	19,672	22,143	24,683	27,293	
		Depr Expense	2,442	2,442	2,455	2,468	2,467	2,466	2,466	2,466	2,471	2,540	2,610	2,619	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**2,442**	**4,884**	**7,339**	**9,807**	**12,274**	**14,740**	**17,206**	**19,672**	**22,143**	**24,683**	**27,293**	**29,911**	
Other	Border Winds Project														
		Plant													
		Beginning Balance	264,595,153	264,595,062	264,595,062	264,595,062	264,616,881	264,616,881	264,616,881	264,616,881	264,616,881	264,616,881	264,980,352	265,005,852	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	(91)	-	-	21,819	-	-	-	-	-	363,471	25,500	250,318	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	264,595,062	264,595,062	264,595,062	264,616,881	264,616,881	264,616,881	264,616,881	264,616,881	264,616,881	264,980,352	265,005,852	265,256,170	
		Reserve													
	Original	Remaining Life (Mos)	240	239	238	237	236	235	234	233	232	231	230	229	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	240	239	238	237	236	235	234	233	232	231	230	229	
		Net Salvage Rate	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	
	Original	Beginning Balance	56,276,853	57,238,557	58,200,260	59,161,963	60,123,716	61,085,519	62,047,322	63,009,126	63,970,929	64,932,732	65,895,389	66,858,963	
		Depr Expense	961,703	961,703	961,703	961,753	961,803	961,803	961,803	961,803	961,803	962,657	963,574	964,288	11,546,400
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(27,533)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	57,238,557	58,200,260	59,161,963	60,123,716	61,085,519	62,047,322	63,009,126	63,970,929	64,932,732	65,895,389	66,858,963	67,795,719	
	Proposed	Beginning Balance	56,276,853	57,249,581	58,222,309	59,195,037	60,167,816	61,140,645	62,113,473	63,086,302	64,059,131	65,031,960	66,005,651	66,980,267	
		Depr Expense	972,728	972,728	972,728	972,778	972,829	972,829	972,829	972,829	972,829	973,691	974,617	975,336	11,678,752
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(27,533)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	57,249,581	58,222,309	59,195,037	60,167,816	61,140,645	62,113,473	63,086,302	64,059,131	65,031,960	66,005,651	66,980,267	67,928,071	
	Change	Beginning Balance	-	11,025	22,050	33,074	44,100	55,125	66,151	77,177	88,203	99,228	110,262	121,304	
		Depr Expense	11,025	11,025	11,025	11,025	11,026	11,026	11,026	11,026	11,026	11,034	11,042	11,048	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**11,025**	**22,050**	**33,074**	**44,100**	**55,125**	**66,151**	**77,177**	**88,203**	**99,228**	**110,262**	**121,304**	**132,352**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Community WF														
		Plant													
		Beginning Balance	64,668,498	64,696,663	64,758,245	64,764,485	64,862,499	64,996,013	65,007,360	65,007,360	65,007,360	65,007,360	65,007,360	65,007,360	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	28,165	61,582	6,240	98,014	133,514	11,346	-	-	-	-	-	141,871	
		Transfers & Adjustments	(0)	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	64,696,663	64,758,245	64,764,485	64,862,499	64,996,013	65,007,360	65,007,360	65,007,360	65,007,360	65,007,360	65,007,360	65,149,231	
		Reserve													
	Original	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	691,692	927,634	1,163,742	1,399,975	1,636,403	1,873,262	2,110,393	2,347,545	2,584,697	2,821,850	3,059,002	3,296,154	
		Depr Expense	235,942	236,108	236,233	236,427	236,860	237,131	237,152	237,152	237,152	237,152	237,152	237,423	2,841,885
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	0	(0)	(0)	0	-	-	-	0	(0)	-	
		Ending Balance	927,634	1,163,742	1,399,975	1,636,403	1,873,262	2,110,393	2,347,545	2,584,697	2,821,850	3,059,002	3,296,154	3,533,577	
	Proposed	Beginning Balance	691,692	927,634	1,163,742	1,399,975	1,636,403	1,873,262	2,110,393	2,347,545	2,584,697	2,821,850	3,059,002	3,296,154	
		Depr Expense	235,942	236,108	236,233	236,427	236,860	237,131	237,152	237,152	237,152	237,152	237,152	237,423	2,841,885
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	0	(0)	(0)	0	-	-	-	0	(0)	-	
		Ending Balance	927,634	1,163,742	1,399,975	1,636,403	1,873,262	2,110,393	2,347,545	2,584,697	2,821,850	3,059,002	3,296,154	3,533,577	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Community Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	27	26	26	26	26	26	26	26	26	26	26	26	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	26	26	26	26	26	26	26	26	26	26	26	25	
	Proposed	Beginning Balance	27	26	26	26	26	26	26	26	26	26	26	26	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	26	26	26	26	26	26	26	26	26	26	26	25	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Courtenay WF**														
		Plant													
		Beginning Balance	279,787,928	279,787,928	279,787,928	279,872,644	280,838,754	280,848,145	281,144,816	281,158,489	281,184,606	281,215,070	281,716,035	281,851,731	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	84,716	966,110	9,391	296,671	13,673	26,116	30,465	500,965	135,696	462,901	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	279,787,928	279,787,928	279,872,644	280,838,754	280,848,145	281,144,816	281,158,489	281,184,606	281,215,070	281,716,035	281,851,731	282,314,631	
		Reserve													
	Original	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	
	Original	Beginning Balance	49,448,717	50,461,152	51,473,587	52,486,207	53,501,125	54,518,186	55,535,922	56,552,136	57,566,459	58,580,893	59,583,721	60,593,056	
		Depr Expense	1,012,435	1,012,435	1,012,620	1,014,918	1,017,061	1,017,736	1,018,427	1,018,529	1,018,673	1,019,908	1,021,402	1,022,885	12,207,028
		Cost of Removal	-	-	-	-	-	-	(2,213)	(4,205)	(4,239)	(17,080)	(12,066)	(50,323)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	-	-	0	(0)	0	0	(0)	-	0	0	
		Ending Balance	50,461,152	51,473,587	52,486,207	53,501,125	54,518,186	55,535,922	56,552,136	57,566,459	58,580,893	59,583,721	60,593,056	61,565,618	
	Proposed	Beginning Balance	49,448,717	50,482,331	51,515,946	52,549,747	53,585,888	54,624,209	55,663,217	56,700,715	57,736,324	58,772,045	59,796,182	60,826,852	
		Depr Expense	1,033,614	1,033,614	1,033,802	1,036,141	1,038,321	1,039,008	1,039,711	1,039,815	1,039,961	1,041,217	1,042,736	1,044,242	12,462,181
		Cost of Removal	-	-	-	-	-	-	(2,213)	(4,205)	(4,239)	(17,080)	(12,066)	(50,323)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	-	-	0	(0)	0	0	(0)	-	0	0	
		Ending Balance	50,482,331	51,515,946	52,549,747	53,585,888	54,624,209	55,663,217	56,700,715	57,736,324	58,772,045	59,796,182	60,826,852	61,820,771	
	Change	Beginning Balance	-	21,179	42,358	63,541	84,763	106,024	127,296	148,580	169,865	191,153	212,462	233,795	
		Depr Expense	21,179	21,179	21,182	21,223	21,260	21,272	21,284	21,286	21,288	21,309	21,334	21,357	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**21,179**	**42,358**	**63,541**	**84,763**	**106,024**	**127,296**	**148,580**	**169,865**	**191,153**	**212,462**	**233,795**	**255,153**	
Other	**Courtenay Wind Rights**														
		Plant													
		Beginning Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Reserve													
	Original	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	343,614	350,555	357,495	364,436	371,376	378,316	385,257	392,197	399,138	406,078	413,019	419,959	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	350,555	357,495	364,436	371,376	378,316	385,257	392,197	399,138	406,078	413,019	419,959	426,899	
	Proposed	Beginning Balance	343,614	350,555	357,495	364,436	371,376	378,316	385,257	392,197	399,138	406,078	413,019	419,959	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	350,555	357,495	364,436	371,376	378,316	385,257	392,197	399,138	406,078	413,019	419,959	426,899	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Crowned Ridge WF														
		Plant													
		Beginning Balance	302,880,388	302,928,446	303,543,541	304,080,598	304,540,656	304,956,122	305,037,298	305,647,276	308,334,835	310,057,696	310,083,075	310,108,455	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	48,058	615,095	537,057	460,057	415,467	81,175	609,979	2,687,559	1,722,861	25,379	25,379	25,379	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	302,928,446	303,543,541	304,080,598	304,540,656	304,956,122	305,037,298	305,647,276	308,334,835	310,057,696	310,083,075	310,108,455	310,133,834	
		Reserve													
	Original	Remaining Life (Mos)	299	298	297	296	295	294	293	292	291	290	289	288	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	299	298	297	296	295	294	293	292	291	290	289	288	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	555,952	1,673,522	2,792,321	3,913,264	5,036,068	6,160,512	7,285,889	8,412,569	9,545,489	10,686,782	11,831,406	12,976,127	
		Depr Expense	1,117,570	1,118,800	1,120,943	1,122,804	1,124,444	1,125,377	1,126,680	1,132,920	1,141,293	1,144,624	1,144,721	1,144,819	13,564,994
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	0	0	(0)	0	(0)	(0)	0	-	-	
		Ending Balance	1,673,522	2,792,321	3,913,264	5,036,068	6,160,512	7,285,889	8,412,569	9,545,489	10,686,782	11,831,406	12,976,127	14,120,946	
	Proposed	Beginning Balance	555,952	1,673,522	2,792,321	3,913,264	5,036,068	6,160,512	7,285,889	8,412,569	9,545,489	10,686,782	11,831,406	12,976,127	
		Depr Expense	1,117,570	1,118,800	1,120,943	1,122,804	1,124,444	1,125,377	1,126,680	1,132,920	1,141,293	1,144,624	1,144,721	1,144,819	13,564,994
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	0	0	(0)	0	(0)	(0)	0	-	-	
		Ending Balance	1,673,522	2,792,321	3,913,264	5,036,068	6,160,512	7,285,889	8,412,569	9,545,489	10,686,782	11,831,406	12,976,127	14,120,946	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Dakota Range WF														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	394,985,740	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	394,985,740	
		Reserve													
	Original	Remaining Life (Mos)	312	311	310	309	308	307	306	305	304	303	302	301	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	312	311	310	309	308	307	306	305	304	303	302	301	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	725,015	725,015
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	725,015	
	Proposed	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	725,015	725,015
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	725,015	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Foxtail WF														
		Plant													
		Beginning Balance	238,892,858	239,046,127	238,484,160	238,499,365	238,627,076	238,778,187	238,936,443	238,963,943	239,011,765	239,014,265	239,050,195	239,050,695	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	153,270	(561,968)	15,205	127,711	151,111	158,256	27,500	47,822	2,500	35,930	500	108,083	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	239,046,127	238,484,160	238,499,365	238,627,076	238,778,187	238,936,443	238,963,943	239,011,765	239,014,265	239,050,195	239,050,695	239,158,778	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	
	Original	Beginning Balance	10,995,671	11,857,776	12,719,109	13,579,404	14,439,971	15,301,071	16,162,764	17,024,815	17,887,010	18,720,388	19,582,859	20,445,402	
		Depr Expense	862,105	861,332	860,295	860,567	861,100	861,693	862,050	862,196	862,293	862,472	862,543	862,755	10,341,402
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(28)	
		Salvage	-	-	-	-	-	-	-	-	(28,916)	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	(0)	(0)	-	0	(0)	-	-	-	-	
		Ending Balance	11,857,776	12,719,109	13,579,404	14,439,971	15,301,071	16,162,764	17,024,815	17,887,010	18,720,388	19,582,859	20,445,402	21,308,129	
	Proposed	Beginning Balance	10,995,671	11,862,755	12,729,062	13,594,325	14,459,863	15,325,936	16,192,605	17,059,633	17,926,808	18,765,165	19,632,617	20,500,140	
		Depr Expense	867,083	866,307	865,264	865,537	866,073	866,669	867,029	867,175	867,273	867,452	867,523	867,737	10,401,121
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(28)	
		Salvage	-	-	-	-	-	-	-	-	(28,916)	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	(0)	(0)	-	0	(0)	-	-	-	-	
		Ending Balance	11,862,755	12,729,062	13,594,325	14,459,863	15,325,936	16,192,605	17,059,633	17,926,808	18,765,165	19,632,617	20,500,140	21,367,849	
	Change	Beginning Balance	-	4,979	9,953	14,921	19,891	24,864	29,841	34,819	39,798	44,777	49,757	54,738	
		Depr Expense	4,979	4,974	4,969	4,970	4,973	4,976	4,978	4,979	4,980	4,980	4,980	4,982	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**4,979**	**9,953**	**14,921**	**19,891**	**24,864**	**29,841**	**34,819**	**39,798**	**44,777**	**49,757**	**54,738**	**59,719**	
Other	Foxtail Wind Rights														
		Plant													
		Beginning Balance	179,743	179,743	179,743	179,743	179,743	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	(2,379)	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	179,743	179,743	179,743	179,743	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	5,739	6,343	6,948	7,552	8,156	8,756	9,352	9,948	10,543	11,139	11,735	12,331	
		Depr Expense	604	604	604	604	600	596	596	596	596	596	596	596	7,187
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	-	-	-	-	-	(0)	0	-	-	
		Ending Balance	6,343	6,948	7,552	8,156	8,756	9,352	9,948	10,543	11,139	11,735	12,331	12,927	
	Proposed	Beginning Balance	5,739	6,343	6,948	7,552	8,156	8,756	9,352	9,948	10,543	11,139	11,735	12,331	
		Depr Expense	604	604	604	604	600	596	596	596	596	596	596	596	7,187
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	-	-	-	-	-	(0)	0	-	-	
		Ending Balance	6,343	6,948	7,552	8,156	8,756	9,352	9,948	10,543	11,139	11,735	12,331	12,927	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Freeborn WF														
		Plant													
		Beginning Balance	-	-	-	-	-	320,253,486	318,807,725	318,745,384	324,429,134	325,243,100	326,680,487	326,968,630	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	320,253,486	(1,445,761)	(62,341)	5,683,750	813,966	1,437,387	288,143	318,218	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	320,253,486	318,807,725	318,745,384	324,429,134	325,243,100	326,680,487	326,968,630	327,286,848	
		Reserve													
	Original	Remaining Life (Mos)	305	304	303	302	301	300	299	298	297	296	295	294	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	305	304	303	302	301	300	299	298	297	296	295	294	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	-	-	-	-	-	587,841	1,762,819	2,935,011	4,117,624	5,312,326	6,511,229	7,713,364	
		Depr Expense	-	-	-	-	587,841	1,174,978	1,172,192	1,182,614	1,194,701	1,198,904	1,202,135	1,203,275	8,916,639
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	(14,811)	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	0	(0)	-	-	
		Ending Balance	-	-	-	-	587,841	1,762,819	2,935,011	4,117,624	5,312,326	6,511,229	7,713,364	8,901,828	
	Proposed	Beginning Balance	-	-	-	-	-	587,841	1,762,819	2,935,011	4,117,624	5,312,326	6,511,229	7,713,364	
		Depr Expense	-	-	-	-	587,841	1,174,978	1,172,192	1,182,614	1,194,701	1,198,904	1,202,135	1,203,275	8,916,639
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	(14,811)	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	0	(0)	-	-	
		Ending Balance	-	-	-	-	587,841	1,762,819	2,935,011	4,117,624	5,312,326	6,511,229	7,713,364	8,901,828	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Fuel Holders (Wind-to-Battery)														
		Plant													
		Beginning Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Reserve													
	Original	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	3,242,796	3,267,410	3,292,024	3,316,638	3,341,252	3,365,866	3,390,480	3,415,094	3,439,708	3,464,322	3,488,936	3,513,551	
		Depr Expense	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	295,369
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	(0)	0	-	-	0	-	(0)	(0)	
		Ending Balance	3,267,410	3,292,024	3,316,638	3,341,252	3,365,866	3,390,480	3,415,094	3,439,708	3,464,322	3,488,936	3,513,551	3,538,165	
	Proposed	Beginning Balance	3,242,796	3,267,410	3,292,024	3,316,638	3,341,252	3,365,866	3,390,480	3,415,094	4,128,902	4,128,902	4,128,902	4,128,902	
		Depr Expense	24,614	24,614	24,614	24,614	24,614	24,614	24,614	713,808	-	-	-	-	886,107
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	(0)	0	-	-	0	-	(0)	(0)	
		Ending Balance	3,267,410	3,292,024	3,316,638	3,341,252	3,365,866	3,390,480	3,415,094	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	689,194	664,580	639,966	615,352	
		Depr Expense	-	-	-	-	-	-	-	689,194	(24,614)	(24,614)	(24,614)	(24,614)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**689,194**	**664,580**	**639,966**	**615,352**	**590,738**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Grand Meadow WF														
		Plant													
		Beginning Balance	201,416,188	201,416,188	200,310,279	200,310,279	200,310,279	200,310,279	200,394,033	200,607,143	200,676,702	201,501,177	202,185,732	202,547,647	
		Retirements	-	(1,105,910)	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	83,755	213,109	69,559	824,476	684,555	361,915	314,744	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	201,416,188	200,310,279	200,310,279	200,310,279	200,310,279	200,394,033	200,607,143	200,676,702	201,501,177	202,185,732	202,547,647	202,862,391	
		Reserve													
	Original	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	
	Proposed	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	
	Original	Beginning Balance	103,265,699	104,043,168	103,619,275	104,396,565	105,173,855	105,951,146	106,728,746	107,505,852	108,273,062	109,034,515	109,743,807	110,488,346	
		Depr Expense	777,469	777,780	777,290	777,290	777,290	777,601	778,713	779,822	783,318	789,408	793,864	796,764	9,386,610
		Cost of Removal	-	(95,763)	-	-	-	-	(1,607)	(12,611)	(21,864)	(80,117)	(49,325)	(34,300)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(1,105,910)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	104,043,168	103,619,275	104,396,565	105,173,855	105,951,146	106,728,746	107,505,852	108,273,062	109,034,515	109,743,807	110,488,346	111,250,810	
	Proposed	Beginning Balance	103,265,699	104,061,360	103,655,659	104,451,041	105,246,423	106,041,804	106,837,500	107,632,715	108,418,047	109,197,666	109,925,195	110,688,021	
		Depr Expense	795,661	795,972	795,382	795,382	795,382	795,696	796,822	797,944	801,483	807,646	812,152	815,085	9,604,606
		Cost of Removal	-	(95,763)	-	-	-	-	(1,607)	(12,611)	(21,864)	(80,117)	(49,325)	(34,300)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(1,105,910)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	104,061,360	103,655,659	104,451,041	105,246,423	106,041,804	106,837,500	107,632,715	108,418,047	109,197,666	109,925,195	110,688,021	111,468,806	
	Change	Beginning Balance	-	18,192	36,385	54,476	72,567	90,659	108,754	126,863	144,985	163,150	181,388	199,676	
		Depr Expense	18,192	18,192	18,091	18,091	18,091	18,095	18,109	18,122	18,165	18,237	18,288	18,321	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**18,192**	**36,385**	**54,476**	**72,567**	**90,659**	**108,754**	**126,863**	**144,985**	**163,150**	**181,388**	**199,676**	**217,996**	
Other	Grand Meadow Wind Rights														
		Plant													
		Beginning Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Reserve													
	Original	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	4,491,769	4,531,645	4,571,520	4,611,395	4,651,271	4,691,146	4,731,021	4,770,897	4,810,772	4,850,648	4,890,523	4,930,398	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,531,645	4,571,520	4,611,395	4,651,271	4,691,146	4,731,021	4,770,897	4,810,772	4,850,648	4,890,523	4,930,398	4,970,274	
	Proposed	Beginning Balance	4,491,769	4,531,645	4,571,520	4,611,395	4,651,271	4,691,146	4,731,021	4,770,897	4,810,772	4,850,648	4,890,523	4,930,398	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,531,645	4,571,520	4,611,395	4,651,271	4,691,146	4,731,021	4,770,897	4,810,772	4,850,648	4,890,523	4,930,398	4,970,274	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	High Bridge														
		Plant													
		Beginning Balance	407,358,682	407,222,633	407,349,618	407,349,618	408,294,855	408,352,361	408,487,655	408,502,993	408,533,527	408,603,049	409,358,640	409,661,400	
		Retirements	-	(8,932)	-	(37,471)	-	(285,747)	-	-	-	-	-	-	
		Additions	(136,049)	135,918	-	982,708	57,506	421,041	15,339	30,534	69,522	755,591	302,760	322,659	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	407,222,633	407,349,618	407,349,618	408,294,855	408,352,361	408,487,655	408,502,993	408,533,527	408,603,049	409,358,640	409,661,400	409,984,059	
		Reserve													
	Original	Remaining Life (Mos)	329	328	327	326	325	324	323	322	321	320	319	318	
		Net Salvage Rate	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	
	Proposed	Remaining Life (Mos)	329	328	327	326	325	324	323	322	321	320	319	318	
		Net Salvage Rate	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	
	Original	Beginning Balance	106,903,420	107,859,780	108,707,157	109,664,037	110,567,194	111,527,341	112,139,059	112,181,384	113,137,020	114,098,438	115,051,121	116,011,370	
		Depr Expense	956,360	956,512	956,880	958,467	960,147	961,009	963,201	964,719	964,900	966,261	968,011	969,961	11,546,429
		Cost of Removal	-	(100,203)	-	(17,839)	-	(63,543)	(920,876)	(9,083)	(3,483)	(13,578)	(7,762)	(584,825)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(8,932)	-	(37,471)	-	(285,747)	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	0	0	0	(0)	(1)	0	0	0	0	(0)	
		Ending Balance	107,859,780	108,707,157	109,664,037	110,567,194	111,527,341	112,139,059	112,181,384	113,137,020	114,098,438	115,051,121	116,011,370	116,396,505	
	Proposed	Beginning Balance	106,903,420	107,869,683	108,726,964	109,693,749	110,606,824	111,576,900	112,198,553	112,250,811	113,216,381	114,187,734	115,150,362	116,120,570	
		Depr Expense	966,264	966,416	966,785	968,384	970,076	970,944	973,135	974,653	974,835	976,206	977,970	979,928	11,665,596
		Cost of Removal	-	(100,203)	-	(17,839)	-	(63,543)	(920,876)	(9,083)	(3,483)	(13,578)	(7,762)	(584,825)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(8,932)	-	(37,471)	-	(285,747)	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	0	0	0	(0)	(1)	0	0	0	0	(0)	
		Ending Balance	107,869,683	108,726,964	109,693,749	110,606,824	111,576,900	112,198,553	112,250,811	113,216,381	114,187,734	115,150,362	116,120,570	116,515,672	
	Change	Beginning Balance	-	9,904	19,807	29,713	39,630	49,559	59,494	69,427	79,361	89,296	99,242	109,201	
		Depr Expense	9,904	9,904	9,905	9,917	9,929	9,935	9,933	9,934	9,935	9,945	9,959	9,967	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**9,904**	**19,807**	**29,713**	**39,630**	**49,559**	**59,494**	**69,427**	**79,361**	**89,296**	**99,242**	**109,201**	**119,167**	
Other	Inver Hills														
		Plant													
		Beginning Balance	59,743,843	59,743,955	59,743,955	59,743,955	59,743,955	59,743,955	58,178,949	58,179,783	58,181,918	58,186,540	58,255,855	58,639,912	
		Retirements	-	-	-	-	-	(1,610,212)	-	-	-	-	-	-	
		Additions	113	-	-	-	-	45,206	833	2,135	4,622	69,315	384,057	29,724	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	59,743,955	59,743,955	59,743,955	59,743,955	59,743,955	58,178,949	58,179,783	58,181,918	58,186,540	58,255,855	58,639,912	58,669,635	
		Reserve													
	Original	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	
	Proposed	Remaining Life (Mos)	72	71	70	69	68	67	66	65	64	63	62	61	
		Net Salvage Rate	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	
	Original	Beginning Balance	58,132,758	58,306,980	58,481,204	58,655,428	58,829,652	59,003,876	57,564,748	57,734,911	57,904,694	58,074,640	58,243,242	58,417,351	
		Depr Expense	174,226	174,227	174,227	174,227	174,227	174,653	170,631	170,669	170,745	171,468	175,830	179,867	2,084,997
		Cost of Removal	-	-	-	-	-	(3,564)	(465)	(884)	(795)	(2,863)	(1,718)	(1,292)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	(1,610,212)	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(6)	(3)	(3)	(3)	(3)	(3)	(3)	
		Ending Balance	58,306,980	58,481,204	58,655,428	58,829,652	59,003,876	57,564,748	57,734,911	57,904,694	58,074,640	58,243,242	58,417,351	58,595,923	
	Proposed	Beginning Balance	58,132,758	58,316,108	58,499,459	58,682,811	58,866,162	59,049,514	57,619,517	57,798,547	57,977,196	58,156,010	58,333,486	58,516,510	
		Depr Expense	183,354	183,355	183,355	183,355	183,355	183,784	179,498	179,536	179,612	180,342	184,744	188,819	2,193,107
		Cost of Removal	-	-	-	-	-	(3,564)	(465)	(884)	(795)	(2,863)	(1,718)	(1,292)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	(1,610,212)	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(6)	(3)	(3)	(3)	(3)	(3)	(3)	
		Ending Balance	58,316,108	58,499,459	58,682,811	58,866,162	59,049,514	57,619,517	57,798,547	57,977,196	58,156,010	58,333,486	58,516,510	58,704,033	
	Change	Beginning Balance	-	9,128	18,255	27,383	36,510	45,638	54,769	63,636	72,503	81,370	90,244	99,159	
		Depr Expense	9,128	9,128	9,128	9,128	9,128	9,131	8,867	8,867	8,868	8,874	8,914	8,952	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**9,128**	**18,255**	**27,383**	**36,510**	**45,638**	**54,769**	**63,636**	**72,503**	**81,370**	**90,244**	**99,159**	**108,110**	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	Jeffers WF														
		Plant													
		Beginning Balance	69,114,496	69,126,414	69,224,937	69,229,373	69,672,691	69,709,704	69,739,079	69,827,349	69,925,834	69,941,679	69,977,609	69,978,109	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	11,918	98,523	4,437	443,317	37,013	29,376	88,270	98,484	15,846	35,930	500	318	
		Transfers & Adjustments	0	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	69,126,414	69,224,937	69,229,373	69,672,691	69,709,704	69,739,079	69,827,349	69,925,834	69,941,679	69,977,609	69,978,109	69,978,427	
		Reserve													
	Original	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	1,509,790	1,759,351	2,009,116	2,259,072	2,509,861	2,761,547	3,013,357	3,265,388	3,517,771	3,770,370	4,023,068	4,275,835	
		Depr Expense	249,561	249,765	249,956	250,789	251,686	251,810	252,031	252,383	252,599	252,698	252,767	252,769	3,018,814
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(33)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	-	-	(0)	(0)	0	(0)	0	(0)	(0)	(0)	
		Ending Balance	1,759,351	2,009,116	2,259,072	2,509,861	2,761,547	3,013,357	3,265,388	3,517,771	3,770,370	4,023,068	4,275,835	4,528,571	
	Proposed	Beginning Balance	1,509,790	1,759,351	2,009,116	2,259,072	2,509,861	2,761,547	3,013,357	3,265,388	3,517,771	3,770,370	4,023,068	4,275,835	
		Depr Expense	249,561	249,765	249,956	250,789	251,686	251,810	252,031	252,383	252,599	252,698	252,767	252,769	3,018,814
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(33)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	-	-	(0)	(0)	0	(0)	0	(0)	(0)	(0)	
		Ending Balance	1,759,351	2,009,116	2,259,072	2,509,861	2,761,547	3,013,357	3,265,388	3,517,771	3,770,370	4,023,068	4,275,835	4,528,571	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Jeffers Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	201	201	200	199	199	198	197	197	196	195	195	194	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	201	200	199	199	198	197	197	196	195	195	194	193	
	Proposed	Beginning Balance	201	201	200	199	199	198	197	197	196	195	195	194	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	201	200	199	199	198	197	197	196	195	195	194	193	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Lake Benton WF**														
		Plant													
		Beginning Balance	158,743,003	158,787,116	158,856,188	159,432,308	159,670,669	159,821,479	160,189,007	160,730,131	161,176,612	161,177,797	161,213,726	161,214,226	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	44,113	69,072	576,119	238,361	150,810	367,528	541,124	446,480	1,185	35,930	500	76,417	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	158,787,116	158,856,188	159,432,308	159,670,669	159,821,479	160,189,007	160,730,131	161,176,612	161,177,797	161,213,726	161,214,226	161,290,643	
		Reserve													
	Original	Remaining Life (Mos)	287	286	285	284	283	282	281	280	279	278	277	276	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	287	286	285	284	283	282	281	280	279	278	277	276	
		Net Salvage Rate	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	
	Original	Beginning Balance	7,672,218	8,245,695	8,819,387	9,394,307	9,970,782	10,548,004	11,126,222	11,706,195	12,288,082	12,870,366	13,453,197	14,036,099	
		Depr Expense	573,477	573,692	574,920	576,476	577,222	578,219	579,973	581,886	582,758	582,831	582,902	583,054	6,947,408
		Cost of Removal	-	-	-	-	-	-	-	-	(474)	-	-	(23)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	(0)	(0)	(0)	(0)	0	-	(0)	-	(0)	-	
		Ending Balance	8,245,695	8,819,387	9,394,307	9,970,782	10,548,004	11,126,222	11,706,195	12,288,082	12,870,366	13,453,197	14,036,099	14,619,130	
	Proposed	Beginning Balance	7,672,218	8,258,419	8,844,838	9,432,512	10,021,774	10,611,798	11,202,841	11,795,675	12,390,463	12,985,667	13,581,420	14,177,245	
		Depr Expense	586,200	586,419	587,674	589,262	590,024	591,043	592,834	594,788	595,678	595,753	595,826	595,980	7,101,481
		Cost of Removal	-	-	-	-	-	-	-	-	(474)	-	-	(23)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	(0)	(0)	(0)	(0)	0	-	(0)	-	(0)	-	
		Ending Balance	8,258,419	8,844,838	9,432,512	10,021,774	10,611,798	11,202,841	11,795,675	12,390,463	12,985,667	13,581,420	14,177,245	14,773,202	
	Change	Beginning Balance	-	12,723	25,451	38,205	50,992	63,795	76,619	89,480	102,381	115,301	128,223	141,146	
		Depr Expense	12,723	12,728	12,754	12,787	12,803	12,824	12,861	12,902	12,920	12,922	12,923	12,926	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**12,723**	**25,451**	**38,205**	**50,992**	**63,795**	**76,619**	**89,480**	**102,381**	**115,301**	**128,223**	**141,146**	**154,072**	
Other	**Lake Benton Wind Rights**														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	287	286	285	284	283	282	281	280	279	278	277	276	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	287	286	285	284	283	282	281	280	279	278	277	276	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Proposed	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Mower WF**														
		Plant													
		Beginning Balance	-	-	-	222,617,090	222,805,968	222,634,769	222,750,571	223,118,411	223,217,337	223,361,602	223,361,602	223,361,602	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	222,617,090	188,878	(171,200)	115,802	367,840	98,926	144,265	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	222,617,090	222,805,968	222,634,769	222,750,571	223,118,411	223,217,337	223,361,602	223,361,602	223,361,602	223,361,602	
		Reserve													
	Original	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	-	-	-	65,771,891	66,379,044	66,986,230	67,593,312	68,201,302	68,810,173	69,419,505	70,029,110	70,638,715	
		Depr Expense	-	-	302,891	607,153	607,186	607,082	607,991	608,871	609,331	609,605	609,605	609,609	5,779,324
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(2,564)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	65,469,001	-	(0)	(0)	-	0	(0)	0	0	(0)	
		Ending Balance	-	-	65,771,891	66,379,044	66,986,230	67,593,312	68,201,302	68,810,173	69,419,505	70,029,110	70,638,715	71,245,760	
	Proposed	Beginning Balance	-	-	-	65,771,891	66,379,044	66,986,230	67,593,312	68,201,302	68,810,173	69,419,505	70,029,110	70,638,715	
		Depr Expense	-	-	302,891	607,153	607,186	607,082	607,991	608,871	609,331	609,605	609,605	609,609	5,779,324
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(2,564)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	65,469,001	-	(0)	(0)	-	0	(0)	0	0	(0)	
		Ending Balance	-	-	65,771,891	66,379,044	66,986,230	67,593,312	68,201,302	68,810,173	69,419,505	70,029,110	70,638,715	71,245,760	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	**Mower Wind Rights**														
		Plant													
		Beginning Balance	-	-	-	626,399	627,152	626,470	626,931	626,931	626,931	626,931	626,931	626,931	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	626,399	753	(682)	462	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	626,399	627,152	626,470	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
		Reserve													
	Original	Remaining Life (Mos)	303	302	301	300	299	298	297	296	295	294	293	292	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	303	302	301	300	299	298	297	296	295	294	293	292	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	-	-	-	1,041	3,126	5,212	7,298	9,384	11,470	13,557	15,643	17,729	
		Depr Expense	-	-	1,041	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	19,816
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	(0)	-	0	0	(0)	-	-	-	
		Ending Balance	-	-	1,041	3,126	5,212	7,298	9,384	11,470	13,557	15,643	17,729	19,816	
	Proposed	Beginning Balance	-	-	-	1,041	3,126	5,212	7,298	9,384	11,470	13,557	15,643	17,729	
		Depr Expense	-	-	1,041	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	19,816
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	(0)	-	0	0	(0)	-	-	-	
		Ending Balance	-	-	1,041	3,126	5,212	7,298	9,384	11,470	13,557	15,643	17,729	19,816	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2021												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Nobles WF														
		Plant													
		Beginning Balance	515,644,783	515,644,783	515,000,389	515,000,389	515,000,389	515,000,389	515,000,389	515,014,903	515,063,680	515,128,867	515,630,959	515,944,688	
		Retirements	-	(644,394)	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	14,514	48,777	65,186	502,092	313,729	366,286	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	515,644,783	515,000,389	515,000,389	515,000,389	515,000,389	515,000,389	515,014,903	515,063,680	515,128,867	515,630,959	515,944,688	516,310,974	
		Reserve													
	Original	Remaining Life (Mos)	179	178	177	176	175	174	173	172	171	170	169	168	
		Net Salvage Rate	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	
	Proposed	Remaining Life (Mos)	179	178	177	176	175	174	173	172	171	170	169	168	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Original	Beginning Balance	215,661,125	217,509,853	218,713,711	220,562,224	222,410,736	224,259,249	226,107,762	227,954,242	229,795,320	231,633,827	233,431,504	235,238,427	
		Depr Expense	1,848,728	1,848,730	1,848,512	1,848,512	1,848,512	1,848,512	1,848,563	1,848,786	1,849,193	1,851,151	1,854,007	1,856,437	22,199,645
		Cost of Removal	-	(478)	-	-	-	-	(2,083)	(7,708)	(10,687)	(53,473)	(47,084)	(48,689)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(644,394)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	217,509,853	218,713,711	220,562,224	222,410,736	224,259,249	226,107,762	227,954,242	229,795,320	231,633,827	233,431,504	235,238,427	237,046,175	
	Proposed	Beginning Balance	215,661,125	217,581,870	218,857,746	220,778,185	222,698,624	224,619,063	226,539,502	228,457,910	230,370,920	232,281,367	234,151,027	236,029,992	
		Depr Expense	1,920,746	1,920,747	1,920,439	1,920,439	1,920,439	1,920,439	1,920,490	1,920,718	1,921,134	1,923,133	1,926,049	1,928,530	23,063,303
		Cost of Removal	-	(478)	-	-	-	-	(2,083)	(7,708)	(10,687)	(53,473)	(47,084)	(48,689)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(644,394)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	217,581,870	218,857,746	220,778,185	222,698,624	224,619,063	226,539,502	228,457,910	230,370,920	232,281,367	234,151,027	236,029,992	237,909,833	
	Change	Beginning Balance	-	72,017	144,035	215,961	287,888	359,814	431,741	503,668	575,600	647,540	719,523	791,565	
		Depr Expense	72,017	72,017	71,926	71,926	71,926	71,926	71,927	71,932	71,940	71,982	72,042	72,093	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**72,017**	**144,035**	**215,961**	**287,888**	**359,814**	**431,741**	**503,668**	**575,600**	**647,540**	**719,523**	**791,565**	**863,658**	
Other	Nobles Wind Rights														
		Plant													
		Beginning Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Reserve													
	Original	Remaining Life (Mos)	179	178	177	176	175	174	173	172	171	170	169	168	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	179	178	177	176	175	174	173	172	171	170	169	168	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,550,454	1,563,495	1,576,537	1,589,578	1,602,619	1,615,660	1,628,702	1,641,743	1,654,784	1,667,825	1,680,866	1,693,908	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	(0)	0	(0)	-	-	(0)	0	(0)	-	
		Ending Balance	1,563,495	1,576,537	1,589,578	1,602,619	1,615,660	1,628,702	1,641,743	1,654,784	1,667,825	1,680,866	1,693,908	1,706,949	
	Proposed	Beginning Balance	1,550,454	1,563,495	1,576,537	1,589,578	1,602,619	1,615,660	1,628,702	1,641,743	1,654,784	1,667,825	1,680,866	1,693,908	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	(0)	0	(0)	-	-	(0)	0	(0)	-	
		Ending Balance	1,563,495	1,576,537	1,589,578	1,602,619	1,615,660	1,628,702	1,641,743	1,654,784	1,667,825	1,680,866	1,693,908	1,706,949	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

								2021							
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Pleasant Valley WF														
		Plant													
		Beginning Balance	332,339,761	332,339,761	332,009,312	332,009,312	332,009,312	332,009,312	332,009,312	332,504,721	332,506,357	332,507,837	332,549,118	332,552,844	
		Retirements	-	(330,449)	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	495,409	1,636	1,480	41,281	3,725	445,453	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	332,339,761	332,009,312	332,009,312	332,009,312	332,009,312	332,009,312	332,504,721	332,506,357	332,507,837	332,549,118	332,552,844	332,998,296	
		Reserve													
	Original	Remaining Life (Mos)	240	239	238	237	236	235	234	233	232	231	230	229	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	240	239	238	237	236	235	234	233	232	231	230	229	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Original	Beginning Balance	73,361,480	74,558,260	75,291,972	76,489,191	77,686,410	78,883,629	80,080,848	81,278,199	82,475,754	83,673,522	84,866,777	86,062,726	
		Depr Expense	1,196,780	1,197,058	1,197,219	1,197,219	1,197,219	1,197,219	1,198,370	1,199,533	1,199,549	1,199,667	1,199,795	1,200,952	14,380,581
		Cost of Removal	-	(132,897)	-	-	-	-	(1,019)	(1,979)	(1,781)	(6,411)	(3,847)	(38,629)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(330,449)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	0	0	0	-	0	-	-	(0)	-	(0)	
		Ending Balance	74,558,260	75,291,972	76,489,191	77,686,410	78,883,629	80,080,848	81,278,199	82,475,754	83,673,522	84,866,777	86,062,726	87,225,049	
	Proposed	Beginning Balance	73,361,480	74,602,572	75,380,596	76,622,082	77,863,569	79,105,055	80,346,542	81,588,194	82,830,085	84,072,188	85,309,783	86,550,074	
		Depr Expense	1,241,092	1,241,370	1,241,487	1,241,487	1,241,487	1,241,487	1,242,671	1,243,869	1,243,885	1,244,006	1,244,137	1,245,326	14,912,301
		Cost of Removal	-	(132,897)	-	-	-	-	(1,019)	(1,979)	(1,781)	(6,411)	(3,847)	(38,629)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	(330,449)	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	0	0	0	-	0	-	-	(0)	-	(0)	
		Ending Balance	74,602,572	75,380,596	76,622,082	77,863,569	79,105,055	80,346,542	81,588,194	82,830,085	84,072,188	85,309,783	86,550,074	87,756,770	
	Change	Beginning Balance	-	44,312	88,624	132,891	177,159	221,427	265,694	309,996	354,331	398,667	443,006	487,347	
		Depr Expense	44,312	44,312	44,268	44,268	44,268	44,268	44,301	44,336	44,336	44,339	44,342	44,373	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**44,312**	**88,624**	**132,891**	**177,159**	**221,427**	**265,694**	**309,996**	**354,331**	**398,667**	**443,006**	**487,347**	**531,721**	
Other	Riverside														
		Plant													
		Beginning Balance	318,333,193	318,298,773	318,354,728	318,357,094	318,302,354	318,302,354	334,992,602	335,633,122	337,254,868	337,390,702	338,083,515	338,605,415	
		Retirements	-	-	-	-	-	(45,892)	-	-	-	-	-	-	
		Additions	(34,420)	55,955	2,366	(54,740)	-	16,736,140	640,521	1,621,745	135,834	692,813	521,900	1,065,163	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	318,298,773	318,354,728	318,357,094	318,302,354	318,302,354	334,992,602	335,633,122	337,254,868	337,390,702	338,083,515	338,605,415	339,670,578	
		Reserve													
	Original	Remaining Life (Mos)	339	338	337	336	335	334	333	332	331	330	329	328	
		Net Salvage Rate	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	
	Proposed	Remaining Life (Mos)	339	338	337	336	335	334	333	332	331	330	329	328	
		Net Salvage Rate	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	
	Original	Beginning Balance	102,504,630	103,247,540	103,990,485	104,733,526	105,476,480	106,219,343	106,937,243	107,703,590	108,476,471	109,251,379	108,872,209	109,493,200	
		Depr Expense	742,717	742,752	742,847	742,760	742,668	770,564	799,648	803,536	806,585	809,832	813,987	817,092	9,334,987
		Cost of Removal	-	-	-	-	-	(6,967)	(33,299)	(30,654)	(31,676)	(1,189,001)	(192,995)	(77,601)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	(45,892)	-	-	-	-	-	-	
		Transfers/Adjustments	194	194	194	194	194	196	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	103,247,540	103,990,485	104,733,526	105,476,480	106,219,343	106,937,243	107,703,590	108,476,471	109,251,379	108,872,209	109,493,200	110,232,690	
	Proposed	Beginning Balance	102,504,630	103,265,381	104,026,167	104,787,052	105,547,847	106,308,549	107,044,765	107,829,922	108,621,676	109,415,509	109,055,287	109,695,261	
		Depr Expense	760,557	760,593	760,690	760,601	760,508	788,880	818,457	822,410	825,509	828,780	832,970	836,121	9,556,077
		Cost of Removal	-	-	-	-	-	(6,967)	(33,299)	(30,654)	(31,676)	(1,189,001)	(192,995)	(77,601)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	(45,892)	-	-	-	-	-	-	
		Transfers/Adjustments	194	194	194	194	194	196	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	103,265,381	104,026,167	104,787,052	105,547,847	106,308,549	107,044,765	107,829,922	108,621,676	109,415,509	109,055,287	109,695,261	110,453,780	
	Change	Beginning Balance	-	17,841	35,682	53,525	71,366	89,206	107,522	126,331	145,205	164,130	183,078	202,061	
		Depr Expense	17,841	17,841	17,843	17,841	17,840	18,316	18,809	18,874	18,924	18,948	18,983	19,029	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**17,841**	**35,682**	**53,525**	**71,366**	**89,206**	**107,522**	**126,331**	**145,205**	**164,130**	**183,078**	**202,061**	**221,090**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 2 & 3														
		Plant													
		Beginning Balance	87,153,399	87,157,763	87,162,187	87,923,636	88,040,395	88,092,631	88,950,176	89,059,583	89,087,289	89,127,967	89,333,124	89,563,400	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	4,364	4,424	761,449	116,759	52,237	857,545	109,407	27,706	40,677	205,157	230,276	219,139	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	87,157,763	87,162,187	87,923,636	88,040,395	88,092,631	88,950,176	89,059,583	89,087,289	89,127,967	89,333,124	89,563,400	89,782,539	
		Reserve													
	Original	Remaining Life (Mos)	228	227	226	225	224	223	222	221	220	219	218	217	
		Net Salvage Rate	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	
	Proposed	Remaining Life (Mos)	228	227	226	225	224	223	222	221	220	219	218	217	
		Net Salvage Rate	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	
	Original	Beginning Balance	68,611,217	68,729,203	68,847,209	68,967,122	69,089,077	69,211,158	69,275,528	69,402,823	69,530,381	69,598,667	69,726,994	69,856,595	
		Depr Expense	118,032	118,054	119,911	122,050	122,464	124,836	127,360	127,700	128,007	128,759	129,855	131,310	1,498,338
		Cost of Removal	(43)	(42)	(62)	(101)	(382)	(60,543)	(73)	(138)	(59,720)	(447)	(268)	(138,562)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(5)	65	6	(1)	76	8	(4)	0	15	14	21	
		Ending Balance	68,729,203	68,847,209	68,967,122	69,089,077	69,211,158	69,275,528	69,402,823	69,530,381	69,598,667	69,726,994	69,856,595	69,849,364	
	Proposed	Beginning Balance	68,680,238	68,804,038	68,927,857	69,053,611	69,181,439	69,309,398	69,379,678	69,512,919	69,646,427	69,720,667	69,854,956	69,990,535	
		Depr Expense	123,846	123,867	125,752	127,922	128,342	130,747	133,305	133,651	133,960	134,721	135,833	137,305	1,569,251
		Cost of Removal	(43)	(42)	(62)	(101)	(382)	(60,543)	(73)	(138)	(59,720)	(447)	(268)	(138,562)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(5)	65	6	(1)	76	8	(4)	0	15	14	21	
		Ending Balance	68,804,038	68,927,857	69,053,611	69,181,439	69,309,398	69,379,678	69,512,919	69,646,427	69,720,667	69,854,956	69,990,535	69,989,298	
	Change	Beginning Balance	69,021	74,835	80,648	86,489	92,361	98,240	104,150	110,096	116,047	122,000	127,962	133,940	
		Depr Expense	5,813	5,814	5,841	5,872	5,878	5,911	5,946	5,951	5,953	5,962	5,978	5,995	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**74,835**	**80,648**	**86,489**	**92,361**	**98,240**	**104,150**	**110,096**	**116,047**	**122,000**	**127,962**	**133,940**	**139,934**	
Other	Angus Anson Unit 2 & 3 - FERC 341														
		Plant													
		Beginning Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Reserve													
	Original	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	5,678,883	5,687,533	5,696,183	5,704,833	5,713,483	5,722,132	5,730,782	5,739,432	5,748,082	5,756,732	5,765,382	5,774,031	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,687,533	5,696,183	5,704,833	5,713,483	5,722,132	5,730,782	5,739,432	5,748,082	5,756,732	5,765,382	5,774,031	5,782,681	
	Proposed	Beginning Balance	5,678,883	5,687,533	5,696,183	5,704,833	5,713,483	5,722,132	5,730,782	5,739,432	5,748,082	5,756,732	5,765,382	5,774,031	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,687,533	5,696,183	5,704,833	5,713,483	5,722,132	5,730,782	5,739,432	5,748,082	5,756,732	5,765,382	5,774,031	5,782,681	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Angus Anson Unit 4**														
		Plant													
		Beginning Balance	38,839,680	38,839,680	38,839,680	40,565,480	42,028,997	42,124,997	42,142,997	42,149,997	42,149,997	46,963,316	46,973,316	46,998,226	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	1,725,800	1,463,517	96,000	18,000	7,000	-	4,813,319	10,000	24,910	3,042	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	38,839,680	38,839,680	40,565,480	42,028,997	42,124,997	42,142,997	42,149,997	42,149,997	46,963,316	46,973,316	46,998,226	47,001,268	
		Reserve													
	Original	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	18,883,603	18,963,606	19,043,610	19,126,908	19,216,314	19,308,719	19,340,569	19,354,450	19,447,646	19,550,231	19,662,259	19,774,355	
		Depr Expense	80,002	80,002	83,296	89,405	92,403	92,733	93,036	93,195	102,583	112,026	112,094	112,520	1,143,297
		Cost of Removal	-	-	-	-	-	(60,885)	(79,157)	-	-	-	-	(200,000)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	2	2	1	2	2	2	2	
		Ending Balance	18,963,606	19,043,610	19,126,908	19,216,314	19,308,719	19,340,569	19,354,450	19,447,646	19,550,231	19,662,259	19,774,355	19,686,877	
	Proposed	Beginning Balance	18,883,603	18,963,606	19,043,610	19,126,908	19,216,314	19,308,719	19,340,569	19,354,450	19,447,646	19,550,231	19,662,259	19,774,355	
		Depr Expense	80,002	80,002	83,296	89,405	92,403	92,733	93,036	93,195	102,583	112,026	112,094	112,520	1,143,297
		Cost of Removal	-	-	-	-	-	(60,885)	(79,157)	-	-	-	-	(200,000)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	2	2	1	2	2	2	2	
		Ending Balance	18,963,606	19,043,610	19,126,908	19,216,314	19,308,719	19,340,569	19,354,450	19,447,646	19,550,231	19,662,259	19,774,355	19,686,877	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	**Black Dog Unit 5**														
		Plant													
		Beginning Balance	198,989,585	199,018,339	199,046,664	199,088,518	199,450,523	199,865,043	199,917,243	200,066,782	200,786,015	200,947,042	217,649,056	222,474,474	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	28,753	28,325	41,854	362,005	414,521	52,200	149,538	719,234	161,027	16,702,014	4,825,417	711,792	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	199,018,339	199,046,664	199,088,518	199,450,523	199,865,043	199,917,243	200,066,782	200,786,015	200,947,042	217,649,056	222,474,474	223,186,266	
		Reserve													
	Original	Remaining Life (Mos)	120	119	118	117	116	115	114	113	112	111	110	109	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	120	119	118	117	116	115	114	113	112	111	110	109	
		Net Salvage Rate	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	
	Original	Beginning Balance	115,140,492	116,028,301	116,916,381	117,804,743	118,694,936	119,573,228	120,469,609	121,364,996	122,250,382	123,149,516	124,139,480	125,197,094	
		Depr Expense	887,916	888,185	888,517	890,441	894,240	896,570	897,567	901,932	906,416	991,073	1,100,279	1,131,924	11,275,058
		Cost of Removal	(107)	(105)	(154)	(249)	(15,947)	(189)	(2,180)	(16,545)	(7,283)	(1,108)	(42,665)	(687,459)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	2	
		Ending Balance	116,028,301	116,916,381	117,804,743	118,694,936	119,573,228	120,469,609	121,364,996	122,250,382	123,149,516	124,139,480	125,197,094	125,641,561	
	Proposed	Beginning Balance	114,392,361	115,216,754	116,041,407	116,866,330	117,693,010	118,507,650	119,340,293	120,171,904	120,993,355	121,828,386	122,751,059	123,737,272	
		Depr Expense	824,499	824,757	825,077	826,929	830,587	832,833	833,792	837,995	842,314	923,781	1,028,877	1,059,455	10,490,898
		Cost of Removal	(107)	(105)	(154)	(249)	(15,947)	(189)	(2,180)	(16,545)	(7,283)	(1,108)	(42,665)	(687,459)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	2	
		Ending Balance	115,216,754	116,041,407	116,866,330	117,693,010	118,507,650	119,340,293	120,171,904	120,993,355	121,828,386	122,751,059	123,737,272	124,109,270	
	Change	Beginning Balance	(748,130)	(811,547)	(874,974)	(938,414)	(1,001,926)	(1,065,578)	(1,129,316)	(1,193,091)	(1,257,028)	(1,321,129)	(1,388,421)	(1,459,822)	
		Depr Expense	(63,417)	(63,427)	(63,440)	(63,512)	(63,653)	(63,738)	(63,775)	(63,936)	(64,101)	(67,292)	(71,402)	(72,468)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(811,547)**	**(874,974)**	**(938,414)**	**(1,001,926)**	**(1,065,578)**	**(1,129,316)**	**(1,193,091)**	**(1,257,028)**	**(1,321,129)**	**(1,388,421)**	**(1,459,822)**	**(1,532,291)**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Black Dog Unit 5 FERC 341**														
		Plant													
		Beginning Balance	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Reserve													
	Original	Remaining Life (Mos)	435	434	433	432	431	430	429	428	427	426	425	424	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	435	434	433	432	431	430	429	428	427	426	425	424	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	28,021,823	28,068,142	28,114,462	28,160,781	28,207,100	28,253,420	28,299,739	28,346,058	28,392,377	28,438,696	28,485,016	28,531,335	
		Depr Expense	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	555,748
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	7	7	7	7	7	7	7	7	7	7	7	7	
		Ending Balance	28,068,142	28,114,462	28,160,781	28,207,100	28,253,420	28,299,739	28,346,058	28,392,377	28,438,696	28,485,016	28,531,335	28,577,654	
	Proposed	Beginning Balance	28,009,053	28,054,309	28,099,564	28,144,820	28,190,075	28,235,330	28,280,585	28,325,841	28,371,096	28,416,351	28,461,606	28,506,861	
		Depr Expense	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	542,980
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	7	7	7	7	7	7	7	7	7	7	7	7	
		Ending Balance	28,054,309	28,099,564	28,144,820	28,190,075	28,235,330	28,280,585	28,325,841	28,371,096	28,416,351	28,461,606	28,506,861	28,552,116	
	Change	Beginning Balance	(12,769)	(13,833)	(14,897)	(15,962)	(17,026)	(18,090)	(19,154)	(20,218)	(21,282)	(22,346)	(23,410)	(24,474)	
		Depr Expense	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(13,833)**	**(14,897)**	**(15,962)**	**(17,026)**	**(18,090)**	**(19,154)**	**(20,218)**	**(21,282)**	**(22,346)**	**(23,410)**	**(24,474)**	**(25,538)**	
Other	**Black Dog Unit 6**														
		Plant													
		Beginning Balance	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,861,393	102,878,893	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	179,228	17,500	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,682,165	102,861,393	102,878,893	102,878,893	
		Reserve													
	Original	Remaining Life (Mos)	435	434	433	432	431	430	429	428	427	426	425	424	
		Net Salvage Rate	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	
	Proposed	Remaining Life (Mos)	435	434	433	432	431	430	429	428	427	426	425	424	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	18,414,041	18,603,491	18,809,050	19,014,610	19,220,169	19,425,728	19,631,287	19,836,847	20,042,406	20,247,965	20,453,745	20,659,769	
		Depr Expense	205,541	205,559	205,559	205,559	205,559	205,559	205,559	205,559	205,559	205,780	206,023	206,046	2,467,866
		Cost of Removal	(16,090)	-	-	-	-	-	-	-	-	-	-	(1,096)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	18,603,491	18,809,050	19,014,610	19,220,169	19,425,728	19,631,287	19,836,847	20,042,406	20,247,965	20,453,745	20,659,769	20,864,719	
	Proposed	Beginning Balance	18,559,817	18,761,443	18,979,178	19,196,912	19,414,647	19,632,382	19,850,117	20,067,852	20,285,587	20,503,322	20,721,289	20,939,511	
		Depr Expense	217,716	217,735	217,735	217,735	217,735	217,735	217,735	217,735	217,735	217,967	218,222	218,246	2,614,032
		Cost of Removal	(16,090)	-	-	-	-	-	-	-	-	-	-	(1,096)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	18,761,443	18,979,178	19,196,912	19,414,647	19,632,382	19,850,117	20,067,852	20,285,587	20,503,322	20,721,289	20,939,511	21,156,661	
	Change	Beginning Balance	145,776	157,952	170,127	182,303	194,478	206,654	218,830	231,005	243,181	255,356	267,543	279,742	
		Depr Expense	12,176	12,176	12,176	12,176	12,176	12,176	12,176	12,176	12,176	12,187	12,199	12,200	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**157,952**	**170,127**	**182,303**	**194,478**	**206,654**	**218,830**	**231,005**	**243,181**	**255,356**	**267,543**	**279,742**	**291,942**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Blazing Star I WF**														
		Plant													
		Beginning Balance	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	
		Reserve													
	Original	Remaining Life (Mos)	280	279	278	277	276	275	274	273	272	271	270	269	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	280	279	278	277	276	275	274	273	272	271	270	269	
		Net Salvage Rate	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	
	Original	Beginning Balance	22,686,898	23,800,112	24,913,326	26,026,556	27,139,770	28,252,984	29,366,198	30,479,412	31,592,627	32,705,841	33,819,055	34,932,269	
		Depr Expense	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	13,358,571
		Cost of Removal	-	-	15	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	-	-	-	-	-	(0)	(0)	-	(0)	
		Ending Balance	23,800,112	24,913,326	26,026,556	27,139,770	28,252,984	29,366,198	30,479,412	31,592,627	32,705,841	33,819,055	34,932,269	36,045,483	
	Proposed	Beginning Balance	23,078,281	24,224,219	25,370,157	26,516,109	27,662,047	28,807,984	29,953,922	31,099,859	32,245,797	33,391,734	34,537,672	35,683,609	
		Depr Expense	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	13,751,250
		Cost of Removal	-	-	15	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	-	-	-	-	-	(0)	(0)	-	(0)	
		Ending Balance	24,224,219	25,370,157	26,516,109	27,662,047	28,807,984	29,953,922	31,099,859	32,245,797	33,391,734	34,537,672	35,683,609	36,829,547	
	Change	Beginning Balance	391,384	424,107	456,830	489,554	522,277	555,000	587,724	620,447	653,170	685,893	718,617	751,340	
		Depr Expense	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**424,107**	**456,830**	**489,554**	**522,277**	**555,000**	**587,724**	**620,447**	**653,170**	**685,893**	**718,617**	**751,340**	**784,063**	
Other	**Blazing Star II WF**														
		Plant													
		Beginning Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	
		Reserve													
	Original	Remaining Life (Mos)	289	288	287	286	285	284	283	282	281	280	279	278	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	289	288	287	286	285	284	283	282	281	280	279	278	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	14,177,227	15,423,373	16,669,518	17,915,664	19,161,809	20,407,954	21,654,100	22,900,245	24,146,391	25,392,536	26,638,681	27,884,827	
		Depr Expense	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	14,953,745
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	0	-	(0)	-	-	-	
		Ending Balance	15,423,373	16,669,518	17,915,664	19,161,809	20,407,954	21,654,100	22,900,245	24,146,391	25,392,536	26,638,681	27,884,827	29,130,972	
	Proposed	Beginning Balance	14,177,227	15,423,373	16,669,518	17,915,664	19,161,809	20,407,954	21,654,100	22,900,245	24,146,391	25,392,536	26,638,681	27,884,827	
		Depr Expense	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	14,953,745
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	0	-	(0)	-	-	-	
		Ending Balance	15,423,373	16,669,518	17,915,664	19,161,809	20,407,954	21,654,100	22,900,245	24,146,391	25,392,536	26,638,681	27,884,827	29,130,972	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 1 thru 4														
		Plant													
		Beginning Balance	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	
		Reserve													
	Original	Remaining Life (Mos)	18	17	16	15	14	13	12	11	10	9	8	7	
		Net Salvage Rate	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	
	Proposed	Remaining Life (Mos)	18	17	16	15	14	13	12	11	10	9	8	7	
		Net Salvage Rate	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	
	Original	Beginning Balance	29,996,479	30,013,628	30,030,777	30,047,926	30,065,075	30,082,224	30,099,373	30,116,522	30,133,671	30,150,820	30,167,969	30,185,118	
		Depr Expense	17,149	17,149	17,149	17,149	17,149	17,149	17,149	17,149	17,149	17,148	17,148	17,148	205,783
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	30,013,628	30,030,777	30,047,926	30,065,075	30,082,224	30,099,373	30,116,522	30,133,671	30,150,820	30,167,969	30,185,118	30,202,267	
	Proposed	Beginning Balance	30,755,798	30,836,246	30,916,693	30,997,141	31,077,589	31,158,037	31,238,485	31,318,932	31,399,380	31,479,828	31,560,275	31,640,723	
		Depr Expense	80,447	80,447	80,447	80,447	80,447	80,447	80,447	80,447	80,447	80,447	80,447	80,447	965,368
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	30,836,246	30,916,693	30,997,141	31,077,589	31,158,037	31,238,485	31,318,932	31,399,380	31,479,828	31,560,275	31,640,723	31,721,170	
	Change	Beginning Balance	759,319	822,618	885,916	949,215	1,012,514	1,075,813	1,139,111	1,202,410	1,265,709	1,329,007	1,392,306	1,455,605	
		Depr Expense	63,299	63,299	63,299	63,299	63,299	63,299	63,299	63,299	63,299	63,299	63,299	63,299	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**822,618**	**885,916**	**949,215**	**1,012,514**	**1,075,813**	**1,139,111**	**1,202,410**	**1,265,709**	**1,329,007**	**1,392,306**	**1,455,605**	**1,518,904**	
Other	Blue Lake Units 1 thru 4 - FERC 341														
		Plant													
		Beginning Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Reserve													
	Original	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	1,096,720	1,097,403	1,098,086	1,098,769	1,099,452	1,100,136	1,100,819	1,101,502	1,102,185	1,102,869	1,103,552	1,104,235	
		Depr Expense	683	683	683	683	683	683	683	683	683	683	683	683	8,199
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	-	0	(0)	-	(0)	(0)	-	-	-	
		Ending Balance	1,097,403	1,098,086	1,098,769	1,099,452	1,100,136	1,100,819	1,101,502	1,102,185	1,102,869	1,103,552	1,104,235	1,104,918	
	Proposed	Beginning Balance	1,097,192	1,097,915	1,098,637	1,099,360	1,100,083	1,100,805	1,101,528	1,102,250	1,102,973	1,103,696	1,104,418	1,105,141	
		Depr Expense	723	723	723	723	723	723	723	723	723	723	723	723	8,671
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	-	0	(0)	-	(0)	(0)	-	-	-	
		Ending Balance	1,097,915	1,098,637	1,099,360	1,100,083	1,100,805	1,101,528	1,102,250	1,102,973	1,103,696	1,104,418	1,105,141	1,105,863	
	Change	Beginning Balance	473	512	551	591	630	669	709	748	788	827	866	906	
		Depr Expense	39	39	39	39	39	39	39	39	39	39	39	39	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**512**	**551**	**591**	**630**	**669**	**709**	**748**	**788**	**827**	**866**	**906**	**945**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 7 & 8														
		Plant													
		Beginning Balance	76,679,218	76,699,693	76,700,173	79,382,882	79,571,469	79,632,056	79,633,195	79,634,402	79,637,000	79,639,734	81,393,080	81,571,313	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	20,475	480	2,682,709	188,587	60,587	1,140	1,207	2,598	2,734	1,753,347	178,233	6,425	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	76,699,693	76,700,173	79,382,882	79,571,469	79,632,056	79,633,195	79,634,402	79,637,000	79,639,734	81,393,080	81,571,313	81,577,739	
		Reserve													
	Original	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	37,395,408	37,307,138	37,479,852	37,657,926	37,841,745	37,975,633	38,069,012	38,253,995	38,438,948	38,623,920	38,812,307	39,004,782	
		Depr Expense	172,231	172,738	178,110	183,878	184,472	184,854	185,025	185,033	185,044	188,651	192,632	193,015	2,205,684
		Cost of Removal	(260,502)	(25)	(37)	(59)	(50,585)	(91,476)	(43)	(82)	(73)	(264)	(159)	(107)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	37,307,138	37,479,852	37,657,926	37,841,745	37,975,633	38,069,012	38,253,995	38,438,948	38,623,920	38,812,307	39,004,782	39,197,690	
	Proposed	Beginning Balance	37,425,319	37,339,672	37,515,009	37,695,754	37,882,296	38,018,911	38,115,019	38,302,731	38,490,412	38,678,112	38,869,261	39,064,532	
		Depr Expense	174,854	175,361	180,781	186,601	187,199	187,583	187,754	187,762	187,773	191,412	195,429	195,815	2,238,323
		Cost of Removal	(260,502)	(25)	(37)	(59)	(50,585)	(91,476)	(43)	(82)	(73)	(264)	(159)	(107)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	37,339,672	37,515,009	37,695,754	37,882,296	38,018,911	38,115,019	38,302,731	38,490,412	38,678,112	38,869,261	39,064,532	39,260,241	
	Change	Beginning Balance	29,911	32,534	35,157	37,828	40,551	43,279	46,007	48,735	51,464	54,193	56,954	59,750	
		Depr Expense	2,623	2,623	2,671	2,723	2,727	2,728	2,728	2,729	2,729	2,761	2,797	2,800	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**32,534**	**35,157**	**37,828**	**40,551**	**43,279**	**46,007**	**48,735**	**51,464**	**54,193**	**56,954**	**59,750**	**62,550**	
Other	Border Winds Project														
		Plant													
		Beginning Balance	265,256,170	265,397,764	265,427,014	265,437,181	265,437,181	265,437,181	265,437,181	265,437,181	265,437,181	265,437,181	266,287,764	266,346,097	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	141,594	29,250	10,167	-	-	-	-	-	-	850,583	58,333	8,333	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	265,397,764	265,427,014	265,437,181	265,437,181	265,437,181	265,437,181	265,437,181	265,437,181	265,437,181	266,287,764	266,346,097	266,354,430	
		Reserve													
	Original	Remaining Life (Mos)	228	227	226	225	224	223	222	221	220	219	218	217	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	228	227	226	225	224	223	222	221	220	219	218	217	
		Net Salvage Rate	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	
	Original	Beginning Balance	67,795,719	68,760,999	69,726,688	70,692,472	71,658,280	72,624,088	73,589,897	74,555,705	75,521,513	76,487,321	77,455,237	78,425,414	
		Depr Expense	965,281	965,689	965,784	965,808	965,808	965,808	965,808	965,808	965,808	967,915	970,177	970,344	11,600,040
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	68,760,999	69,726,688	70,692,472	71,658,280	72,624,088	73,589,897	74,555,705	75,521,513	76,487,321	77,455,237	78,425,414	79,395,757	
	Proposed	Beginning Balance	67,928,071	68,904,408	69,881,157	70,858,002	71,834,872	72,811,742	73,788,612	74,765,481	75,742,351	76,719,221	77,698,217	78,679,496	
		Depr Expense	976,338	976,750	976,845	976,870	976,870	976,870	976,870	976,870	976,870	978,996	981,279	981,447	11,732,874
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	68,904,408	69,881,157	70,858,002	71,834,872	72,811,742	73,788,612	74,765,481	75,742,351	76,719,221	77,698,217	78,679,496	79,660,943	
	Change	Beginning Balance	132,352	143,409	154,469	165,530	176,592	187,653	198,715	209,776	220,838	231,899	242,980	254,082	
		Depr Expense	11,057	11,060	11,061	11,062	11,062	11,062	11,062	11,062	11,062	11,081	11,102	11,103	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**143,409**	**154,469**	**165,530**	**176,592**	**187,653**	**198,715**	**209,776**	**220,838**	**231,899**	**242,980**	**254,082**	**265,185**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Community WF														
		Plant													
		Beginning Balance	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	3,533,577	3,771,272	4,008,968	4,246,663	4,484,359	4,722,055	4,959,750	5,197,446	5,435,141	5,672,837	5,910,532	6,148,228	
		Depr Expense	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	2,852,347
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	-	0	(0)	-	-	-	(0)	0	0	(0)	
		Ending Balance	3,771,272	4,008,968	4,246,663	4,484,359	4,722,055	4,959,750	5,197,446	5,435,141	5,672,837	5,910,532	6,148,228	6,385,924	
	Proposed	Beginning Balance	3,533,577	3,771,272	4,008,968	4,246,663	4,484,359	4,722,055	4,959,750	5,197,446	5,435,141	5,672,837	5,910,532	6,148,228	
		Depr Expense	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	2,852,347
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	-	0	(0)	-	-	-	(0)	0	0	(0)	
		Ending Balance	3,771,272	4,008,968	4,246,663	4,484,359	4,722,055	4,959,750	5,197,446	5,435,141	5,672,837	5,910,532	6,148,228	6,385,924	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Community Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	25	25	25	25	25	25	25	25	25	25	25	25	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	25	25	25	25	25	25	25	25	25	25	25	24	
	Proposed	Beginning Balance	25	25	25	25	25	25	25	25	25	25	25	25	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	25	25	25	25	25	25	25	25	25	25	25	24	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	Courtenay WF														
		Plant													
		Beginning Balance	282,314,631	282,319,855	282,325,001	282,332,604	282,344,960	282,392,132	282,401,615	282,410,671	282,427,961	282,443,601	282,500,140	282,534,206	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	5,224	5,146	7,603	12,355	47,173	9,483	9,055	17,291	15,639	56,539	34,066	564,190	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	282,319,855	282,325,001	282,332,604	282,344,960	282,392,132	282,401,615	282,410,671	282,427,961	282,443,601	282,500,140	282,534,206	283,098,396	
		Reserve													
	Original	Remaining Life (Mos)	239	238	237	236	235	234	233	232	231	230	229	228	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	239	238	237	236	235	234	233	232	231	230	229	228	
		Net Salvage Rate	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	
	Original	Beginning Balance	61,565,618	62,589,237	63,612,890	64,636,374	65,659,521	66,679,980	67,703,659	68,727,423	69,750,595	70,773,989	71,794,314	72,816,671	
		Depr Expense	1,024,054	1,024,079	1,024,110	1,024,160	1,024,308	1,024,449	1,024,495	1,024,561	1,024,644	1,024,827	1,025,058	1,026,609	12,295,354
		Cost of Removal	(435)	(426)	(626)	(1,013)	(3,849)	(770)	(731)	(1,389)	(1,250)	(4,502)	(2,701)	(55,823)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	0	(0)	-	0	0	(0)	-	0	(0)	0	
		Ending Balance	62,589,237	63,612,890	64,636,374	65,659,521	66,679,980	67,703,659	68,727,423	69,750,595	70,773,989	71,794,314	72,816,671	73,787,457	
	Proposed	Beginning Balance	61,820,771	62,865,766	63,910,795	64,955,656	66,000,181	67,042,020	68,087,081	69,132,229	70,176,785	71,221,564	72,263,279	73,307,028	
		Depr Expense	1,045,430	1,045,455	1,045,487	1,045,538	1,045,688	1,045,831	1,045,878	1,045,946	1,046,030	1,046,216	1,046,450	1,048,027	12,551,976
		Cost of Removal	(435)	(426)	(626)	(1,013)	(3,849)	(770)	(731)	(1,389)	(1,250)	(4,502)	(2,701)	(55,823)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	0	(0)	-	0	0	(0)	-	0	(0)	0	
		Ending Balance	62,865,766	63,910,795	64,955,656	66,000,181	67,042,020	68,087,081	69,132,229	70,176,785	71,221,564	72,263,279	73,307,028	74,299,231	
	Change	Beginning Balance	255,153	276,529	297,905	319,282	340,660	362,040	383,423	404,806	426,190	447,576	468,965	490,357	
		Depr Expense	21,376	21,376	21,377	21,378	21,380	21,382	21,383	21,384	21,386	21,389	21,392	21,417	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**276,529**	**297,905**	**319,282**	**340,660**	**362,040**	**383,423**	**404,806**	**426,190**	**447,576**	**468,965**	**490,357**	**511,774**	
Other	Courtenay Wind Rights														
		Plant													
		Beginning Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Reserve													
	Original	Remaining Life (Mos)	239	238	237	236	235	234	233	232	231	230	229	228	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	239	238	237	236	235	234	233	232	231	230	229	228	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	426,899	433,840	440,780	447,721	454,661	461,601	468,542	475,482	482,423	489,363	496,304	503,244	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	433,840	440,780	447,721	454,661	461,601	468,542	475,482	482,423	489,363	496,304	503,244	510,184	
	Proposed	Beginning Balance	426,899	433,840	440,780	447,721	454,661	461,601	468,542	475,482	482,423	489,363	496,304	503,244	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	433,840	440,780	447,721	454,661	461,601	468,542	475,482	482,423	489,363	496,304	503,244	510,184	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Crowned Ridge WF**														
		Plant													
		Beginning Balance	310,133,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	2,400,000	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	
		Reserve													
	Original	Remaining Life (Mos)	287	286	285	284	283	282	281	280	279	278	277	276	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	287	286	285	284	283	282	281	280	279	278	277	276	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	14,120,946	15,267,762	16,421,895	17,576,029	18,730,162	19,884,295	21,038,429	22,192,562	23,346,695	24,500,829	25,654,962	26,809,095	
		Depr Expense	1,149,492	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	13,844,959
		Cost of Removal	(2,676)	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	-	0	-	-	0	(0)	-	-	-	0	
		Ending Balance	15,267,762	16,421,895	17,576,029	18,730,162	19,884,295	21,038,429	22,192,562	23,346,695	24,500,829	25,654,962	26,809,095	27,963,228	
	Proposed	Beginning Balance	14,120,946	15,267,762	16,421,895	17,576,029	18,730,162	19,884,295	21,038,429	22,192,562	23,346,695	24,500,829	25,654,962	26,809,095	
		Depr Expense	1,149,492	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	13,844,959
		Cost of Removal	(2,676)	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	-	0	-	-	0	(0)	-	-	-	0	
		Ending Balance	15,267,762	16,421,895	17,576,029	18,730,162	19,884,295	21,038,429	22,192,562	23,346,695	24,500,829	25,654,962	26,809,095	27,963,228	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	**Dakota Range WF**														
		Plant													
		Beginning Balance	394,985,740	395,106,865	395,220,544	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	121,126	113,678	(7,097,583)	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	395,106,865	395,220,544	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	
		Reserve													
	Original	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	300	299	298	297	296	295	294	293	292	291	290	289	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	725,015	2,177,686	3,630,790	5,068,181	6,495,143	7,922,105	9,349,067	10,776,029	12,202,990	13,629,952	15,056,914	16,483,876	
		Depr Expense	1,452,671	1,453,104	1,440,156	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	17,188,588
		Cost of Removal	-	-	(26)	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	(2,739)	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,177,686	3,630,790	5,068,181	6,495,143	7,922,105	9,349,067	10,776,029	12,202,990	13,629,952	15,056,914	16,483,876	17,910,838	
	Proposed	Beginning Balance	725,015	2,177,686	3,630,790	5,068,181	6,495,143	7,922,105	9,349,067	10,776,029	12,202,990	13,629,952	15,056,914	16,483,876	
		Depr Expense	1,452,671	1,453,104	1,440,156	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	17,188,588
		Cost of Removal	-	-	(26)	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	(2,739)	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,177,686	3,630,790	5,068,181	6,495,143	7,922,105	9,349,067	10,776,029	12,202,990	13,629,952	15,056,914	16,483,876	17,910,838	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Foxtail WF**														
		Plant													
		Beginning Balance	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	
	Original	Beginning Balance	21,308,129	22,171,097	23,034,065	23,897,033	24,760,001	25,622,969	26,485,937	27,348,905	28,211,873	29,074,841	29,937,809	30,800,776	
		Depr Expense	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	10,355,615
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	-	0	0	(0)	0	0	-	0	-	0	
		Ending Balance	22,171,097	23,034,065	23,897,033	24,760,001	25,622,969	26,485,937	27,348,905	28,211,873	29,074,841	29,937,809	30,800,776	31,663,744	
	Proposed	Beginning Balance	21,367,849	22,235,799	23,103,750	23,971,701	24,839,651	25,707,602	26,575,553	27,443,503	28,311,454	29,179,405	30,047,355	30,915,306	
		Depr Expense	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	10,415,408
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	-	0	0	(0)	0	0	-	0	-	0	
		Ending Balance	22,235,799	23,103,750	23,971,701	24,839,651	25,707,602	26,575,553	27,443,503	28,311,454	29,179,405	30,047,355	30,915,306	31,783,257	
	Change	Beginning Balance	59,719	64,702	69,685	74,668	79,650	84,633	89,616	94,598	99,581	104,564	109,547	114,529	
		Depr Expense	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**64,702**	**69,685**	**74,668**	**79,650**	**84,633**	**89,616**	**94,598**	**99,581**	**104,564**	**109,547**	**114,529**	**119,512**	
Other	**Foxtail Wind Rights**														
		Plant													
		Beginning Balance	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	12,927	13,522	14,118	14,714	15,310	15,906	16,501	17,097	17,693	18,289	18,884	19,480	
		Depr Expense	596	596	596	596	596	596	596	596	596	596	596	596	7,149
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	-	(0)	0	-	-	-	(0)	
		Ending Balance	13,522	14,118	14,714	15,310	15,906	16,501	17,097	17,693	18,289	18,884	19,480	20,076	
	Proposed	Beginning Balance	12,927	13,522	14,118	14,714	15,310	15,906	16,501	17,097	17,693	18,289	18,884	19,480	
		Depr Expense	596	596	596	596	596	596	596	596	596	596	596	596	7,149
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	-	(0)	0	-	-	-	(0)	
		Ending Balance	13,522	14,118	14,714	15,310	15,906	16,501	17,097	17,693	18,289	18,884	19,480	20,076	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Northern States Power Company
Other Production

Docket No. E002/GR-21-633
Exhibit___(MPM-1), Schedule 6
Page 79 of 122

Functional Class	Plant Name		January 2022	February	March	April	May	June	July	August	September	October	November	December	
Other	**Freeborn WF**														
		Plant													
		Beginning Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	
		Reserve													
	Original	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	8,901,828	10,105,753	11,309,679	12,513,604	13,717,529	14,921,455	16,125,380	17,329,306	18,533,231	19,737,156	20,941,082	22,145,007	
		Depr Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,105
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	-	-	-	(0)	0	-	0	(0)	
		Ending Balance	10,105,753	11,309,679	12,513,604	13,717,529	14,921,455	16,125,380	17,329,306	18,533,231	19,737,156	20,941,082	22,145,007	23,348,932	
	Proposed	Beginning Balance	8,901,828	10,105,753	11,309,679	12,513,604	13,717,529	14,921,455	16,125,380	17,329,306	18,533,231	19,737,156	20,941,082	22,145,007	
		Depr Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,105
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	-	-	-	(0)	0	-	0	(0)	
		Ending Balance	10,105,753	11,309,679	12,513,604	13,717,529	14,921,455	16,125,380	17,329,306	18,533,231	19,737,156	20,941,082	22,145,007	23,348,932	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		January 2022	February	March	April	May	June	July	August	September	October	November	December	
Other	**Fuel Holders (Wind-to-Battery)**														
		Plant													
		Beginning Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Reserve													
	Original	Remaining Life (Mos)	24	23	22	21	20	19	18	17	16	15	14	13	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	3,538,165	3,562,779	3,587,393	3,612,007	3,636,621	3,661,235	3,685,849	3,710,463	3,735,077	3,759,691	3,784,305	3,808,919	
		Depr Expense	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	295,369
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	-	-	-	0	(0)	-	-	-	-	-	
		Ending Balance	3,562,779	3,587,393	3,612,007	3,636,621	3,661,235	3,685,849	3,710,463	3,735,077	3,759,691	3,784,305	3,808,919	3,833,533	
	Proposed	Beginning Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	-	-	-	0	(0)	-	-	-	-	-	
		Ending Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
	Change	Beginning Balance	590,738	566,124	541,510	516,895	492,281	467,667	443,053	418,439	393,825	369,211	344,597	319,983	
		Depr Expense	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**566,124**	**541,510**	**516,895**	**492,281**	**467,667**	**443,053**	**418,439**	**393,825**	**369,211**	**344,597**	**319,983**	**295,369**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Grand Meadow WF														
		Plant													
		Beginning Balance	202,862,391	202,955,030	202,961,447	202,971,667	202,989,504	203,062,528	203,078,438	203,094,860	203,128,680	203,161,730	203,291,453	203,379,453	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	92,639	6,417	10,220	17,837	73,024	15,910	16,423	33,820	33,051	129,723	88,000	313,755	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	202,955,030	202,961,447	202,971,667	202,989,504	203,062,528	203,078,438	203,094,860	203,128,680	203,161,730	203,291,453	203,379,453	203,693,209	
		Reserve													
	Original	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	
	Proposed	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	
	Original	Beginning Balance	111,250,810	112,007,493	112,805,769	113,603,625	114,400,626	115,190,909	115,989,033	116,787,269	117,583,601	118,380,386	119,165,898	119,957,759	
		Depr Expense	798,614	799,152	799,225	799,350	799,755	800,155	800,301	800,529	800,835	801,585	802,595	804,459	9,606,556
		Cost of Removal	(41,931)	(875)	(1,369)	(2,349)	(9,472)	(2,031)	(2,066)	(4,197)	(4,050)	(16,072)	(10,734)	(35,023)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	112,007,493	112,805,769	113,603,625	114,400,626	115,190,909	115,989,033	116,787,269	117,583,601	118,380,386	119,165,898	119,957,759	120,727,195	
	Proposed	Beginning Balance	111,468,806	112,243,830	113,060,452	113,876,655	114,692,003	115,500,639	116,317,120	117,133,714	117,948,407	118,763,556	119,567,442	120,377,688	
		Depr Expense	816,954	817,497	817,572	817,698	818,108	818,512	818,660	818,891	819,200	819,958	820,980	822,865	9,826,894
		Cost of Removal	(41,931)	(875)	(1,369)	(2,349)	(9,472)	(2,031)	(2,066)	(4,197)	(4,050)	(16,072)	(10,734)	(35,023)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	112,243,830	113,060,452	113,876,655	114,692,003	115,500,639	116,317,120	117,133,714	117,948,407	118,763,556	119,567,442	120,377,688	121,165,530	
	Change	Beginning Balance	217,996	236,337	254,683	273,029	291,377	309,729	328,086	346,445	364,806	383,171	401,544	419,929	
		Depr Expense	18,341	18,346	18,346	18,348	18,352	18,357	18,359	18,361	18,365	18,373	18,385	18,406	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**236,337**	**254,683**	**273,029**	**291,377**	**309,729**	**328,086**	**346,445**	**364,806**	**383,171**	**401,544**	**419,929**	**438,334**	
Other	Grand Meadow Wind Rights														
		Plant													
		Beginning Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Reserve													
	Original	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	4,970,274	5,010,149	5,050,024	5,089,900	5,129,775	5,169,651	5,209,526	5,249,401	5,289,277	5,329,152	5,369,027	5,408,903	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	(0)	-	0	(0)	-	-	-	-	(0)	
		Ending Balance	5,010,149	5,050,024	5,089,900	5,129,775	5,169,651	5,209,526	5,249,401	5,289,277	5,329,152	5,369,027	5,408,903	5,448,778	
	Proposed	Beginning Balance	4,970,274	5,010,149	5,050,024	5,089,900	5,129,775	5,169,651	5,209,526	5,249,401	5,289,277	5,329,152	5,369,027	5,408,903	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	(0)	-	0	(0)	-	-	-	-	(0)	
		Ending Balance	5,010,149	5,050,024	5,089,900	5,129,775	5,169,651	5,209,526	5,249,401	5,289,277	5,329,152	5,369,027	5,408,903	5,448,778	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2022												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**High Bridge**														
		Plant													
		Beginning Balance	409,984,059	409,992,162	410,000,834	410,390,255	410,505,312	410,628,573	410,660,066	410,695,757	410,779,043	410,889,202	412,243,604	412,909,768	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	8,103	8,672	389,421	115,057	123,261	31,494	35,691	83,286	110,159	1,354,403	666,164	285,259	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	409,992,162	410,000,834	410,390,255	410,505,312	410,628,573	410,660,066	410,695,757	410,779,043	410,889,202	412,243,604	412,909,768	413,195,026	
		Reserve													
	Original	Remaining Life (Mos)	317	316	315	314	313	312	311	310	309	308	307	306	
		Net Salvage Rate	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	
	Proposed	Remaining Life (Mos)	317	316	315	314	313	312	311	310	309	308	307	306	
		Net Salvage Rate	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	
	Original	Beginning Balance	116,396,505	117,367,801	118,339,126	119,311,048	120,283,688	121,255,889	122,229,255	123,198,752	124,172,261	125,146,137	126,121,518	127,093,850	
		Depr Expense	971,424	971,451	972,106	972,938	973,334	973,593	973,712	973,918	974,243	976,707	980,128	981,925	11,695,481
		Cost of Removal	(128)	(126)	(185)	(298)	(1,134)	(227)	(4,215)	(409)	(368)	(1,326)	(7,795)	(107,552)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	117,367,801	118,339,126	119,311,048	120,283,688	121,255,889	122,229,255	123,198,752	124,172,261	125,146,137	126,121,518	127,093,850	127,968,224	
	Proposed	Beginning Balance	116,515,672	117,496,939	118,478,235	119,460,133	120,442,755	121,424,942	122,408,296	123,387,781	124,371,280	125,355,148	126,340,541	127,322,911	
		Depr Expense	981,394	981,422	982,082	982,921	983,320	983,581	983,701	983,908	984,236	986,718	990,166	991,976	11,815,424
		Cost of Removal	(128)	(126)	(185)	(298)	(1,134)	(227)	(4,215)	(409)	(368)	(1,326)	(7,795)	(107,552)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	117,496,939	118,478,235	119,460,133	120,442,755	121,424,942	122,408,296	123,387,781	124,371,280	125,355,148	126,340,541	127,322,911	128,207,334	
	Change	Beginning Balance	119,167	129,138	139,109	149,085	159,068	169,053	179,041	189,029	199,019	209,011	219,023	229,060	
		Depr Expense	9,971	9,971	9,976	9,982	9,986	9,988	9,988	9,990	9,992	10,011	10,038	10,050	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**129,138**	**139,109**	**149,085**	**159,068**	**169,053**	**179,041**	**189,029**	**199,019**	**209,011**	**219,023**	**229,060**	**239,111**	
Other	**Inver Hills**														
		Plant													
		Beginning Balance	58,669,635	58,670,220	58,670,809	58,671,707	58,673,234	59,045,971	61,207,331	61,213,719	61,217,307	61,220,680	61,233,291	61,618,359	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	585	589	899	1,527	372,737	2,161,361	6,388	3,588	3,372	12,611	385,069	12,808	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	58,670,220	58,670,809	58,671,707	58,673,234	59,045,971	61,207,331	61,213,719	61,217,307	61,220,680	61,233,291	61,618,359	61,631,167	
		Reserve													
	Original	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	
	Proposed	Remaining Life (Mos)	60	59	58	57	56	55	54	53	52	51	50	49	
		Net Salvage Rate	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	
	Original	Beginning Balance	58,595,923	58,776,069	58,955,836	59,136,004	59,316,173	59,500,113	59,711,510	59,923,051	60,158,712	60,350,882	60,587,464	60,828,873	
		Depr Expense	180,177	180,193	180,212	180,238	184,194	211,450	235,416	235,754	236,258	236,878	241,588	246,394	2,548,750
		Cost of Removal	(28)	(423)	(41)	(66)	(251)	(50)	(23,872)	(91)	(44,084)	(293)	(176)	(119)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	
		Ending Balance	58,776,069	58,955,836	59,136,004	59,316,173	59,500,113	59,711,510	59,923,051	60,158,712	60,350,882	60,587,464	60,828,873	61,075,145	
	Proposed	Beginning Balance	58,704,033	58,893,133	59,081,854	59,270,977	59,460,101	59,653,033	59,873,675	60,094,682	60,339,809	60,541,447	60,787,498	61,038,420	
		Depr Expense	189,131	189,147	189,166	189,193	193,186	220,695	244,882	245,221	245,725	246,347	251,101	255,951	2,659,745
		Cost of Removal	(28)	(423)	(41)	(66)	(251)	(50)	(23,872)	(91)	(44,084)	(293)	(176)	(119)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	
		Ending Balance	58,893,133	59,081,854	59,270,977	59,460,101	59,653,033	59,873,675	60,094,682	60,339,809	60,541,447	60,787,498	61,038,420	61,294,249	
	Change	Beginning Balance	108,110	117,064	126,019	134,973	143,928	152,920	162,165	171,630	181,097	190,565	200,034	209,547	
		Depr Expense	8,954	8,954	8,955	8,955	8,992	9,245	9,466	9,467	9,468	9,469	9,513	9,558	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**117,064**	**126,019**	**134,973**	**143,928**	**152,920**	**162,165**	**171,630**	**181,097**	**190,565**	**200,034**	**209,547**	**219,105**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Jeffers WF														
		Plant													
		Beginning Balance	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	4,528,571	4,781,340	5,034,109	5,286,879	5,539,648	5,792,418	6,045,187	6,297,957	6,550,726	6,803,495	7,056,265	7,309,034	
		Depr Expense	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	3,033,233
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	(0)	0	-	-	-	-	-	
		Ending Balance	4,781,340	5,034,109	5,286,879	5,539,648	5,792,418	6,045,187	6,297,957	6,550,726	6,803,495	7,056,265	7,309,034	7,561,804	
	Proposed	Beginning Balance	4,528,571	4,781,340	5,034,109	5,286,879	5,539,648	5,792,418	6,045,187	6,297,957	6,550,726	6,803,495	7,056,265	7,309,034	
		Depr Expense	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	3,033,233
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	(0)	0	-	-	-	-	-	
		Ending Balance	4,781,340	5,034,109	5,286,879	5,539,648	5,792,418	6,045,187	6,297,957	6,550,726	6,803,495	7,056,265	7,309,034	7,561,804	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Jeffers Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	193	193	192	191	191	190	189	189	188	187	187	186	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	193	192	191	191	190	189	189	188	187	187	186	185	
	Proposed	Beginning Balance	193	193	192	191	191	190	189	189	188	187	187	186	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	193	192	191	191	190	189	189	188	187	187	186	185	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Lake Benton WF														
		Plant													
		Beginning Balance	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	
		Reserve													
	Original	Remaining Life (Mos)	275	274	273	272	271	270	269	268	267	266	265	264	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	275	274	273	272	271	270	269	268	267	266	265	264	
		Net Salvage Rate	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	
	Original	Beginning Balance	14,619,130	15,202,334	15,785,539	16,368,743	16,951,948	17,535,152	18,118,357	18,701,561	19,284,765	19,867,970	20,451,174	21,034,379	
		Depr Expense	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	6,998,453
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	0	(0)	0	-	
		Ending Balance	15,202,334	15,785,539	16,368,743	16,951,948	17,535,152	18,118,357	18,701,561	19,284,765	19,867,970	20,451,174	21,034,379	21,617,583	
	Proposed	Beginning Balance	14,773,202	15,369,336	15,965,470	16,561,604	17,157,738	17,753,872	18,350,006	18,946,140	19,542,274	20,138,408	20,734,542	21,330,676	
		Depr Expense	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	7,153,607
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	0	(0)	0	-	
		Ending Balance	15,369,336	15,965,470	16,561,604	17,157,738	17,753,872	18,350,006	18,946,140	19,542,274	20,138,408	20,734,542	21,330,676	21,926,809	
	Change	Beginning Balance	154,072	167,002	179,931	192,861	205,790	218,720	231,649	244,579	257,508	270,438	283,367	296,297	
		Depr Expense	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**167,002**	**179,931**	**192,861**	**205,790**	**218,720**	**231,649**	**244,579**	**257,508**	**270,438**	**283,367**	**296,297**	**309,226**	
Other	Lake Benton Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	275	274	273	272	271	270	269	268	267	266	265	264	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	275	274	273	272	271	270	269	268	267	266	265	264	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Proposed	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2022												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Mower WF														
		Plant													
		Beginning Balance	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	71,245,760	71,855,374	72,464,988	73,074,602	73,684,216	74,293,830	74,903,444	75,513,057	76,122,671	76,732,285	77,341,899	77,951,513	
		Depr Expense	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	7,315,367
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	(0)	-	(0)	(0)	-	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	71,855,374	72,464,988	73,074,602	73,684,216	74,293,830	74,903,444	75,513,057	76,122,671	76,732,285	77,341,899	77,951,513	78,561,127	
	Proposed	Beginning Balance	71,245,760	71,855,374	72,464,988	73,074,602	73,684,216	74,293,830	74,903,444	75,513,057	76,122,671	76,732,285	77,341,899	77,951,513	
		Depr Expense	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	7,315,367
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	(0)	-	(0)	(0)	-	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	71,855,374	72,464,988	73,074,602	73,684,216	74,293,830	74,903,444	75,513,057	76,122,671	76,732,285	77,341,899	77,951,513	78,561,127	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Mower Wind Rights														
		Plant													
		Beginning Balance	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
		Reserve													
	Original	Remaining Life (Mos)	291	290	289	288	287	286	285	284	283	282	281	280	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	291	290	289	288	287	286	285	284	283	282	281	280	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	19,816	21,902	23,988	26,075	28,161	30,247	32,333	34,420	36,506	38,592	40,679	42,765	
		Depr Expense	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	25,036
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	0	(0)	-	(0)	0	0	(0)	-	-	
		Ending Balance	21,902	23,988	26,075	28,161	30,247	32,333	34,420	36,506	38,592	40,679	42,765	44,851	
	Proposed	Beginning Balance	19,816	21,902	23,988	26,075	28,161	30,247	32,333	34,420	36,506	38,592	40,679	42,765	
		Depr Expense	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	25,036
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	0	(0)	-	(0)	0	0	(0)	-	-	
		Ending Balance	21,902	23,988	26,075	28,161	30,247	32,333	34,420	36,506	38,592	40,679	42,765	44,851	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

								2022							
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Nobles WF**														
		Plant													
		Beginning Balance	516,310,974	516,317,915	516,325,572	516,338,118	516,360,555	516,454,420	516,475,340	516,497,367	516,543,529	516,589,383	516,835,621	516,945,787	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	(462,853,037)	
		Additions	6,941	7,658	12,546	22,437	93,865	20,920	22,027	46,161	45,854	246,238	110,165	230,518,922	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	516,317,915	516,325,572	516,338,118	516,360,555	516,454,420	516,475,340	516,497,367	516,543,529	516,589,383	516,835,621	516,945,787	284,611,671	
		Reserve													
	Original	Remaining Life (Mos)	167	166	165	164	163	162	161	160	159	158	157	156	
		Net Salvage Rate	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	
	Proposed	Remaining Life (Mos)	167	166	165	164	163	162	161	160	159	158	157	156	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Original	Beginning Balance	237,046,175	238,902,757	240,759,325	242,615,242	244,469,837	246,314,340	248,170,210	250,026,164	251,879,133	253,732,627	255,569,372	257,415,222	
		Depr Expense	1,857,771	1,857,825	1,857,900	1,858,029	1,858,461	1,858,889	1,859,049	1,859,304	1,859,650	1,860,725	1,862,057	2,645,710	23,095,369
		Cost of Removal	(1,189)	(1,257)	(1,983)	(3,434)	(13,958)	(3,019)	(3,095)	(6,335)	(6,156)	(23,981)	(16,207)	(16,895)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	(462,853,037)	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	(68)	
		Ending Balance	238,902,757	240,759,325	242,615,242	244,469,837	246,314,340	248,170,210	250,026,164	251,879,133	253,732,627	255,569,372	257,415,222	(202,809,068)	
	Proposed	Beginning Balance	237,909,833	239,838,536	241,767,226	243,695,266	245,621,988	247,538,626	249,466,640	251,394,742	253,319,863	255,245,517	257,154,445	259,072,507	
		Depr Expense	1,929,892	1,929,947	1,930,023	1,930,155	1,930,596	1,931,033	1,931,196	1,931,457	1,931,810	1,932,908	1,934,268	2,736,402	23,979,687
		Cost of Removal	(1,189)	(1,257)	(1,983)	(3,434)	(13,958)	(3,019)	(3,095)	(6,335)	(6,156)	(23,981)	(16,207)	(16,895)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	(462,853,037)	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	(68)	
		Ending Balance	239,838,536	241,767,226	243,695,266	245,621,988	247,538,626	249,466,640	251,394,742	253,319,863	255,245,517	257,154,445	259,072,507	(201,061,092)	
	Change	Beginning Balance	863,658	935,779	1,007,901	1,080,025	1,152,151	1,224,286	1,296,430	1,368,578	1,440,730	1,512,890	1,585,073	1,657,285	
		Depr Expense	72,121	72,122	72,124	72,126	72,135	72,144	72,147	72,153	72,160	72,183	72,211	90,691	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**935,779**	**1,007,901**	**1,080,025**	**1,152,151**	**1,224,286**	**1,296,430**	**1,368,578**	**1,440,730**	**1,512,890**	**1,585,073**	**1,657,285**	**1,747,976**	
Other	**Nobles Wind Rights**														
		Plant													
		Beginning Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Reserve													
	Original	Remaining Life (Mos)	167	166	165	164	163	162	161	160	159	158	157	156	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	167	166	165	164	163	162	161	160	159	158	157	156	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,706,949	1,719,990	1,733,031	1,746,073	1,759,114	1,772,155	1,785,196	1,798,238	1,811,279	1,824,320	1,837,361	1,850,402	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	(0)	-	(0)	0	-	-	-	-	-	
		Ending Balance	1,719,990	1,733,031	1,746,073	1,759,114	1,772,155	1,785,196	1,798,238	1,811,279	1,824,320	1,837,361	1,850,402	1,863,444	
	Proposed	Beginning Balance	1,706,949	1,719,990	1,733,031	1,746,073	1,759,114	1,772,155	1,785,196	1,798,238	1,811,279	1,824,320	1,837,361	1,850,402	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	(0)	-	(0)	0	-	-	-	-	-	
		Ending Balance	1,719,990	1,733,031	1,746,073	1,759,114	1,772,155	1,785,196	1,798,238	1,811,279	1,824,320	1,837,361	1,850,402	1,863,444	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2022 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Pleasant Valley WF														
		Plant													
		Beginning Balance	332,998,296	333,009,210	333,019,960	333,035,846	333,061,659	333,160,214	333,180,026	333,972,920	334,085,822	334,152,163	334,270,286	334,341,459	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	10,913	10,751	15,885	25,813	98,555	19,812	792,893	112,902	66,341	118,123	71,172	490,137	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	333,009,210	333,019,960	333,035,846	333,061,659	333,160,214	333,180,026	333,972,920	334,085,822	334,152,163	334,270,286	334,341,459	334,831,596	
		Reserve													
	Original	Remaining Life (Mos)	228	227	226	225	224	223	222	221	220	219	218	217	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	228	227	226	225	224	223	222	221	220	219	218	217	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Original	Beginning Balance	87,225,049	88,426,231	89,627,487	90,828,378	92,028,539	93,222,872	94,424,196	95,627,596	96,831,802	98,011,822	99,210,331	100,413,253	
		Depr Expense	1,202,125	1,202,181	1,202,250	1,202,358	1,202,683	1,202,993	1,204,987	1,207,221	1,207,733	1,208,275	1,208,782	1,210,291	14,461,878
		Cost of Removal	(943)	(925)	(1,359)	(2,197)	(8,350)	(1,670)	(1,586)	(3,014)	(27,713)	(9,766)	(5,860)	(39,955)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	0	-	(0)	0	(0)	(0)	-	-	0	-	
		Ending Balance	88,426,231	89,627,487	90,828,378	92,028,539	93,222,872	94,424,196	95,627,596	96,831,802	98,011,822	99,210,331	100,413,253	101,583,589	
	Proposed	Beginning Balance	87,756,770	89,002,357	90,248,020	91,493,319	92,737,892	93,976,646	95,222,398	96,470,286	97,719,046	98,943,631	100,186,720	101,434,236	
		Depr Expense	1,246,530	1,246,588	1,246,659	1,246,770	1,247,104	1,247,422	1,249,474	1,251,774	1,252,299	1,252,855	1,253,376	1,254,926	14,995,776
		Cost of Removal	(943)	(925)	(1,359)	(2,197)	(8,350)	(1,670)	(1,586)	(3,014)	(27,713)	(9,766)	(5,860)	(39,955)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	0	-	(0)	0	(0)	(0)	-	-	0	-	
		Ending Balance	89,002,357	90,248,020	91,493,319	92,737,892	93,976,646	95,222,398	96,470,286	97,719,046	98,943,631	100,186,720	101,434,236	102,649,206	
	Change	Beginning Balance	531,721	576,126	620,533	664,941	709,353	753,774	798,203	842,690	887,243	931,809	976,389	1,020,983	
		Depr Expense	44,405	44,407	44,409	44,412	44,421	44,429	44,488	44,553	44,566	44,580	44,594	44,635	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**576,126**	**620,533**	**664,941**	**709,353**	**753,774**	**798,203**	**842,690**	**887,243**	**931,809**	**976,389**	**1,020,983**	**1,065,618**	
Other	Riverside														
		Plant													
		Beginning Balance	339,670,578	339,697,751	339,724,535	339,763,632	339,993,166	340,641,663	340,768,643	341,290,010	341,491,276	342,260,643	343,736,370	346,884,009	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	27,173	26,783	39,098	229,534	648,497	126,979	521,367	201,266	769,368	1,475,727	3,147,639	549,921	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	339,697,751	339,724,535	339,763,632	339,993,166	340,641,663	340,768,643	341,290,010	341,491,276	342,260,643	343,736,370	346,884,009	347,433,930	
		Reserve													
	Original	Remaining Life (Mos)	327	326	325	324	323	322	321	320	319	318	317	316	
		Net Salvage Rate	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	
	Proposed	Remaining Life (Mos)	327	326	325	324	323	322	321	320	319	318	317	316	
		Net Salvage Rate	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	
	Original	Beginning Balance	110,232,690	111,050,777	111,868,979	112,686,844	113,504,303	114,316,880	115,137,775	115,893,012	116,715,108	117,534,204	118,354,932	119,162,712	
		Depr Expense	819,071	819,166	819,283	819,750	821,280	822,636	823,870	825,239	826,949	830,906	839,088	845,671	9,912,908
		Cost of Removal	(983)	(964)	(1,416)	(2,290)	(8,702)	(1,740)	(68,632)	(3,141)	(7,852)	(10,178)	(31,307)	(13,402)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	111,050,777	111,868,979	112,686,844	113,504,303	114,316,880	115,137,775	115,893,012	116,715,108	117,534,204	118,354,932	119,162,712	119,994,980	
	Proposed	Beginning Balance	110,453,780	111,290,928	112,128,192	112,965,122	113,801,653	114,633,328	115,473,344	116,247,721	117,088,979	117,927,265	118,767,250	119,594,427	
		Depr Expense	838,132	838,229	838,347	838,822	840,378	841,757	843,010	844,400	846,140	850,164	858,484	865,178	10,143,041
		Cost of Removal	(983)	(964)	(1,416)	(2,290)	(8,702)	(1,740)	(68,632)	(3,141)	(7,852)	(10,178)	(31,307)	(13,402)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	111,290,928	112,128,192	112,965,122	113,801,653	114,633,328	115,473,344	116,247,721	117,088,979	117,927,265	118,767,250	119,594,427	120,446,202	
	Change	Beginning Balance	221,090	240,151	259,213	278,278	297,350	316,448	335,569	354,709	373,871	393,061	412,319	431,715	
		Depr Expense	19,061	19,062	19,064	19,072	19,098	19,121	19,140	19,162	19,191	19,258	19,396	19,507	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**240,151**	**259,213**	**278,278**	**297,350**	**316,448**	**335,569**	**354,709**	**373,871**	**393,061**	**412,319**	**431,715**	**451,222**	

			2023												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 2 & 3														
		Plant													
		Beginning Balance	89,782,539	89,793,839	89,800,781	89,807,686	100,138,852	100,493,370	100,508,235	100,522,841	100,541,623	100,564,079	100,752,336	100,889,588	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	11,299	6,943	6,905	10,331,166	354,518	14,866	14,606	18,783	22,456	188,257	137,251	149,135	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	89,793,839	89,800,781	89,807,686	100,138,852	100,493,370	100,508,235	100,522,841	100,541,623	100,564,079	100,752,336	100,889,588	101,038,722	
		Reserve													
	Original	Remaining Life (Mos)	216	215	214	213	212	211	210	209	208	207	206	205	
		Net Salvage Rate	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	
	Proposed	Remaining Life (Mos)	216	215	214	213	212	211	210	209	208	207	206	205	
		Net Salvage Rate	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	
	Original	Beginning Balance	69,849,364	69,972,098	70,100,823	70,231,588	70,388,900	70,565,778	70,751,413	70,488,333	70,674,748	70,861,621	71,040,846	71,225,549	
		Depr Expense	132,237	132,314	132,362	158,967	186,615	187,602	188,760	189,937	190,061	190,655	191,565	192,358	2,073,433
		Cost of Removal	(9,504)	(3,582)	(1,591)	(2,572)	(9,774)	(1,955)	(451,857)	(3,529)	(3,176)	(11,432)	(6,859)	(4,630)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	(6)	(6)	917	37	(12)	17	6	(13)	3	(2)	(1)	
		Ending Balance	69,972,098	70,100,823	70,231,588	70,388,900	70,565,778	70,751,413	70,488,333	70,674,748	70,861,621	71,040,846	71,225,549	71,413,277	
	Proposed	Beginning Balance	69,989,298	70,118,035	70,252,765	70,389,533	70,553,238	70,736,912	70,929,357	70,673,088	70,866,315	71,060,002	71,246,049	71,437,587	
		Depr Expense	138,240	138,318	138,366	165,359	193,411	194,412	195,571	196,749	196,875	197,477	198,399	199,204	2,152,382
		Cost of Removal	(9,504)	(3,582)	(1,591)	(2,572)	(9,774)	(1,955)	(451,857)	(3,529)	(3,176)	(11,432)	(6,859)	(4,630)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	(6)	(6)	917	37	(12)	17	6	(13)	3	(2)	(1)	
		Ending Balance	70,118,035	70,252,765	70,389,533	70,553,238	70,736,912	70,929,357	70,673,088	70,866,315	71,060,002	71,246,049	71,437,587	71,632,160	
	Change	Beginning Balance	139,934	145,937	151,941	157,946	164,338	171,134	177,944	184,755	191,567	198,381	205,203	212,038	
		Depr Expense	6,003	6,004	6,004	6,393	6,796	6,810	6,811	6,812	6,814	6,822	6,835	6,846	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**145,937**	**151,941**	**157,946**	**164,338**	**171,134**	**177,944**	**184,755**	**191,567**	**198,381**	**205,203**	**212,038**	**218,883**	
Other	Angus Anson Unit 2 & 3 - FERC 341														
		Plant													
		Beginning Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Reserve													
	Original	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	5,782,681	5,791,331	5,799,981	5,808,631	5,817,281	5,825,930	5,834,580	5,843,230	5,851,880	5,860,530	5,869,179	5,877,829	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,791,331	5,799,981	5,808,631	5,817,281	5,825,930	5,834,580	5,843,230	5,851,880	5,860,530	5,869,179	5,877,829	5,886,479	
	Proposed	Beginning Balance	5,782,681	5,791,331	5,799,981	5,808,631	5,817,281	5,825,930	5,834,580	5,843,230	5,851,880	5,860,530	5,869,179	5,877,829	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,791,331	5,799,981	5,808,631	5,817,281	5,825,930	5,834,580	5,843,230	5,851,880	5,860,530	5,869,179	5,877,829	5,886,479	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 4														
		Plant													
		Beginning Balance	47,001,268	47,003,310	47,003,310	47,003,310	47,003,310	47,003,310	47,025,812	47,028,012	47,030,212	47,030,212	47,478,189	47,521,998	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	2,042	-	-	-	-	22,503	2,200	2,200	-	447,976	43,809	43,809	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	47,003,310	47,003,310	47,003,310	47,003,310	47,003,310	47,025,812	47,028,012	47,030,212	47,030,212	47,478,189	47,521,998	47,565,807	
		Reserve													
	Original	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	19,686,877	19,794,291	19,907,219	20,020,147	20,133,075	20,246,002	20,358,976	20,471,999	20,581,438	20,694,488	20,808,456	20,923,435	
		Depr Expense	112,912	112,926	112,926	112,926	112,926	112,972	113,022	113,037	113,049	113,966	114,977	115,158	1,360,798
		Cost of Removal	(5,500)	-	-	-	-	-	-	(3,600)	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	2	2	2	2	2	2	2	2	2	2	2	2	
		Ending Balance	19,794,291	19,907,219	20,020,147	20,133,075	20,246,002	20,358,976	20,471,999	20,581,438	20,694,488	20,808,456	20,923,435	21,038,595	
	Proposed	Beginning Balance	19,686,877	19,794,291	19,907,219	20,020,147	20,133,075	20,246,002	20,358,976	20,471,999	20,581,438	20,694,488	20,808,456	20,923,435	
		Depr Expense	112,912	112,926	112,926	112,926	112,926	112,972	113,022	113,037	113,049	113,966	114,977	115,158	1,360,798
		Cost of Removal	(5,500)	-	-	-	-	-	-	(3,600)	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	2	2	2	2	2	2	2	2	2	2	2	2	
		Ending Balance	19,794,291	19,907,219	20,020,147	20,133,075	20,246,002	20,358,976	20,471,999	20,581,438	20,694,488	20,808,456	20,923,435	21,038,595	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Black Dog Unit 5														
		Plant													
		Beginning Balance	223,186,266	223,198,594	223,210,783	223,228,139	223,412,228	223,724,714	223,778,155	223,829,314	224,126,223	224,284,782	225,072,977	225,844,751	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	12,328	12,189	17,356	184,089	312,487	53,440	51,159	296,909	158,560	788,195	771,774	422,446	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	223,198,594	223,210,783	223,228,139	223,412,228	223,724,714	223,778,155	223,829,314	224,126,223	224,284,782	225,072,977	225,844,751	226,267,196	
		Reserve													
	Original	Remaining Life (Mos)	108	107	106	105	104	103	102	101	100	99	98	97	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	108	107	106	105	104	103	102	101	100	99	98	97	
		Net Salvage Rate	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	
	Original	Beginning Balance	125,641,561	126,780,391	127,911,884	129,051,063	130,191,300	131,334,126	132,479,010	133,624,466	134,771,824	135,921,724	137,065,202	138,229,379	
		Depr Expense	1,138,841	1,139,004	1,139,194	1,140,263	1,142,923	1,144,903	1,145,474	1,147,394	1,149,931	1,155,318	1,164,245	1,171,155	13,778,645
		Cost of Removal	(11)	(7,511)	(16)	(26)	(97)	(19)	(18)	(35)	(32)	(11,840)	(68)	(10,046)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	126,780,391	127,911,884	129,051,063	130,191,300	131,334,126	132,479,010	133,624,466	134,771,824	135,921,724	137,065,202	138,229,379	139,390,488	
	Proposed	Beginning Balance	124,109,270	125,175,491	126,234,370	127,300,929	128,368,506	129,438,572	130,510,620	131,583,220	132,657,650	133,734,525	134,804,778	135,895,395	
		Depr Expense	1,066,232	1,066,390	1,066,575	1,067,603	1,070,163	1,072,068	1,072,618	1,074,465	1,076,907	1,082,092	1,090,685	1,097,336	12,903,133
		Cost of Removal	(11)	(7,511)	(16)	(26)	(97)	(19)	(18)	(35)	(32)	(11,840)	(68)	(10,046)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	125,175,491	126,234,370	127,300,929	128,368,506	129,438,572	130,510,620	131,583,220	132,657,650	133,734,525	134,804,778	135,895,395	136,982,685	
	Change	Beginning Balance	(1,532,291)	(1,604,900)	(1,677,514)	(1,750,134)	(1,822,794)	(1,895,554)	(1,968,389)	(2,041,246)	(2,114,175)	(2,187,199)	(2,260,425)	(2,333,984)	
		Depr Expense	(72,609)	(72,614)	(72,620)	(72,660)	(72,760)	(72,835)	(72,857)	(72,929)	(73,025)	(73,225)	(73,560)	(73,818)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(1,604,900)**	**(1,677,514)**	**(1,750,134)**	**(1,822,794)**	**(1,895,554)**	**(1,968,389)**	**(2,041,246)**	**(2,114,175)**	**(2,187,199)**	**(2,260,425)**	**(2,333,984)**	**(2,407,803)**	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Black Dog Unit 5 FERC 341**														
		Plant													
		Beginning Balance	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Reserve													
	Original	Remaining Life (Mos)	423	422	421	420	419	418	417	416	415	414	413	412	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	423	422	421	420	419	418	417	416	415	414	413	412	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	28,577,654	28,623,973	28,670,291	28,716,610	28,762,929	28,809,248	28,855,567	28,901,885	28,948,204	28,994,523	29,040,841	29,087,160	
		Depr Expense	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	555,746
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	7	7	7	7	7	7	7	7	7	6	6	6	
		Ending Balance	28,623,973	28,670,291	28,716,610	28,762,929	28,809,248	28,855,567	28,901,885	28,948,204	28,994,523	29,040,841	29,087,160	29,133,478	
	Proposed	Beginning Balance	28,552,116	28,597,371	28,642,626	28,687,880	28,733,135	28,778,390	28,823,645	28,868,899	28,914,154	28,959,409	29,004,663	29,049,918	
		Depr Expense	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	542,978
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	7	7	7	7	7	7	7	7	7	6	6	6	
		Ending Balance	28,597,371	28,642,626	28,687,880	28,733,135	28,778,390	28,823,645	28,868,899	28,914,154	28,959,409	29,004,663	29,049,918	29,095,172	
	Change	Beginning Balance	(25,538)	(26,602)	(27,666)	(28,730)	(29,794)	(30,858)	(31,922)	(32,986)	(34,050)	(35,114)	(36,178)	(37,242)	
		Depr Expense	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(26,602)**	**(27,666)**	**(28,730)**	**(29,794)**	**(30,858)**	**(31,922)**	**(32,986)**	**(34,050)**	**(35,114)**	**(36,178)**	**(37,242)**	**(38,306)**	
Other	**Black Dog Unit 6**														
		Plant													
		Beginning Balance	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	
		Reserve													
	Original	Remaining Life (Mos)	423	422	421	420	419	418	417	416	415	414	413	412	
		Net Salvage Rate	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	
	Proposed	Remaining Life (Mos)	423	422	421	420	419	418	417	416	415	414	413	412	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	20,864,719	21,070,767	21,276,814	21,482,862	21,688,909	21,894,957	22,101,004	22,307,052	22,513,099	22,719,146	22,925,194	23,131,241	
		Depr Expense	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	2,472,571
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	21,070,767	21,276,814	21,482,862	21,688,909	21,894,957	22,101,004	22,307,052	22,513,099	22,719,146	22,925,194	23,131,241	23,337,289	
	Proposed	Beginning Balance	21,156,661	21,374,909	21,593,157	21,811,404	22,029,652	22,247,899	22,466,147	22,684,394	22,902,642	23,120,889	23,339,137	23,557,385	
		Depr Expense	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	2,618,972
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	21,374,909	21,593,157	21,811,404	22,029,652	22,247,899	22,466,147	22,684,394	22,902,642	23,120,889	23,339,137	23,557,385	23,775,632	
	Change	Beginning Balance	291,942	304,142	316,342	328,542	340,743	352,943	365,143	377,343	389,543	401,743	413,943	426,143	
		Depr Expense	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**304,142**	**316,342**	**328,542**	**340,743**	**352,943**	**365,143**	**377,343**	**389,543**	**401,743**	**413,943**	**426,143**	**438,343**	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Blazing Star I WF**														
		Plant													
		Beginning Balance	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	
		Reserve													
	Original	Remaining Life (Mos)	268	267	266	265	264	263	262	261	260	259	258	257	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	268	267	266	265	264	263	262	261	260	259	258	257	
		Net Salvage Rate	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	
	Original	Beginning Balance	36,045,483	37,158,698	38,271,912	39,385,126	40,498,340	41,611,554	42,724,768	43,837,983	44,951,197	46,064,411	47,177,625	48,290,839	
		Depr Expense	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	13,358,570
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	(0)	-	-	(0)	(0)	-	(0)	-	(0)	
		Ending Balance	37,158,698	38,271,912	39,385,126	40,498,340	41,611,554	42,724,768	43,837,983	44,951,197	46,064,411	47,177,625	48,290,839	49,404,054	
	Proposed	Beginning Balance	36,829,547	37,975,484	39,121,422	40,267,359	41,413,297	42,559,234	43,705,172	44,851,109	45,997,047	47,142,984	48,288,922	49,434,859	
		Depr Expense	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	13,751,250
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	(0)	-	-	(0)	(0)	-	(0)	-	(0)	
		Ending Balance	37,975,484	39,121,422	40,267,359	41,413,297	42,559,234	43,705,172	44,851,109	45,997,047	47,142,984	48,288,922	49,434,859	50,580,797	
	Change	Beginning Balance	784,063	816,787	849,510	882,233	914,957	947,680	980,403	1,013,127	1,045,850	1,078,573	1,111,296	1,144,020	
		Depr Expense	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**816,787**	**849,510**	**882,233**	**914,957**	**947,680**	**980,403**	**1,013,127**	**1,045,850**	**1,078,573**	**1,111,296**	**1,144,020**	**1,176,743**	
Other	**Blazing Star II WF**														
		Plant													
		Beginning Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	
		Reserve													
	Original	Remaining Life (Mos)	277	276	275	274	273	272	271	270	269	268	267	266	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	277	276	275	274	273	272	271	270	269	268	267	266	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	29,130,972	30,377,118	31,623,263	32,869,408	34,115,554	35,361,699	36,607,845	37,853,990	39,100,135	40,346,281	41,592,426	42,838,571	
		Depr Expense	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	14,953,745
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	(0)	0	-	-	-	-	-	-	-	
		Ending Balance	30,377,118	31,623,263	32,869,408	34,115,554	35,361,699	36,607,845	37,853,990	39,100,135	40,346,281	41,592,426	42,838,571	44,084,717	
	Proposed	Beginning Balance	29,130,972	30,377,118	31,623,263	32,869,408	34,115,554	35,361,699	36,607,845	37,853,990	39,100,135	40,346,281	41,592,426	42,838,571	
		Depr Expense	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	14,953,745
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	(0)	0	-	-	-	-	-	-	-	
		Ending Balance	30,377,118	31,623,263	32,869,408	34,115,554	35,361,699	36,607,845	37,853,990	39,100,135	40,346,281	41,592,426	42,838,571	44,084,717	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 1 thru 4														
		Plant													
		Beginning Balance	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	(0)	(0)	(0)	(0)	(0)	(0)	
		Retirements	-	-	-	-	-	(24,658,386)	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	24,658,386	24,658,386	24,658,386	24,658,386	24,658,386	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Reserve													
	Original	Remaining Life (Mos)	6	5	4	3	2	1	-	-	-	-	-	-	
		Net Salvage Rate	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	
	Proposed	Remaining Life (Mos)	6	5	4	3	2	1	-	-	-	-	-	-	
		Net Salvage Rate	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	
	Original	Beginning Balance	30,202,267	30,219,416	30,236,564	30,253,713	30,270,861	30,288,009	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	
		Depr Expense	17,148	17,148	17,148	17,148	17,148	16,988	-	-	-	-	-	-	102,729
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	(24,658,386)	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	319	-	-	-	-	-	-	
		Ending Balance	30,219,416	30,236,564	30,253,713	30,270,861	30,288,009	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	
	Proposed	Beginning Balance	31,721,170	31,801,618	31,882,065	31,962,512	32,042,959	32,123,406	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	
		Depr Expense	80,447	80,447	80,447	80,447	80,446	80,287	-	-	-	-	-	-	482,521
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	(24,658,386)	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	319	-	-	-	-	-	-	
		Ending Balance	31,801,618	31,882,065	31,962,512	32,042,959	32,123,406	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	
	Change	Beginning Balance	1,518,904	1,582,202	1,645,501	1,708,800	1,772,098	1,835,397	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	
		Depr Expense	63,299	63,299	63,299	63,299	63,299	63,299	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,582,202**	**1,645,501**	**1,708,800**	**1,772,098**	**1,835,397**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	
Other	Blue Lake Units 1 thru 4 - FERC 341														
		Plant													
		Beginning Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Reserve													
	Original	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	1,104,918	1,105,602	1,106,285	1,106,968	1,107,651	1,108,334	1,109,018	1,109,701	1,110,384	1,111,067	1,111,751	1,112,434	
		Depr Expense	683	683	683	683	683	683	683	683	683	683	683	683	8,199
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	(0)	-	-	-	(0)	-	-	(0)	-	-	
		Ending Balance	1,105,602	1,106,285	1,106,968	1,107,651	1,108,334	1,109,018	1,109,701	1,110,384	1,111,067	1,111,751	1,112,434	1,113,117	
	Proposed	Beginning Balance	1,105,863	1,106,586	1,107,309	1,108,031	1,108,754	1,109,476	1,110,199	1,110,922	1,111,644	1,112,367	1,113,089	1,113,812	
		Depr Expense	723	723	723	723	723	723	723	723	723	723	723	723	8,671
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	(0)	-	-	-	(0)	-	-	(0)	-	-	
		Ending Balance	1,106,586	1,107,309	1,108,031	1,108,754	1,109,476	1,110,199	1,110,922	1,111,644	1,112,367	1,113,089	1,113,812	1,114,535	
	Change	Beginning Balance	945	985	1,024	1,063	1,103	1,142	1,181	1,221	1,260	1,300	1,339	1,378	
		Depr Expense	39	39	39	39	39	39	39	39	39	39	39	39	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**985**	**1,024**	**1,063**	**1,103**	**1,142**	**1,181**	**1,221**	**1,260**	**1,300**	**1,339**	**1,378**	**1,418**	

			2023												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 7 & 8														
		Plant													
		Beginning Balance	81,577,739	81,577,902	82,034,794	82,079,694	82,124,839	82,127,198	82,127,772	82,128,440	82,130,005	82,131,806	82,511,566	87,612,663	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	164	456,892	44,900	45,145	2,359	574	667	1,566	1,800	379,761	5,101,097	6,044	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	81,577,902	82,034,794	82,079,694	82,124,839	82,127,198	82,127,772	82,128,440	82,130,005	82,131,806	82,511,566	87,612,663	87,618,707	
		Reserve													
	Original	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	39,197,690	39,390,717	39,584,697	39,779,725	39,974,940	40,170,237	40,365,560	40,560,885	40,756,212	40,951,546	41,147,680	41,355,645	
		Depr Expense	193,029	193,981	195,031	195,220	195,320	195,326	195,329	195,334	195,341	196,161	207,980	219,675	2,377,726
		Cost of Removal	(3)	(3)	(4)	(6)	(23)	(5)	(4)	(8)	(8)	(27)	(16)	(330,011)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	39,390,717	39,584,697	39,779,725	39,974,940	40,170,237	40,365,560	40,560,885	40,756,212	40,951,546	41,147,680	41,355,645	41,245,310	
	Proposed	Beginning Balance	39,260,241	39,456,068	39,652,856	39,850,702	40,048,736	40,246,855	40,444,998	40,643,144	40,841,291	41,039,446	41,238,409	41,449,307	
		Depr Expense	195,829	196,790	197,849	198,040	198,141	198,147	198,150	198,155	198,162	198,989	210,914	222,708	2,411,871
		Cost of Removal	(3)	(3)	(4)	(6)	(23)	(5)	(4)	(8)	(8)	(27)	(16)	(330,011)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	39,456,068	39,652,856	39,850,702	40,048,736	40,246,855	40,444,998	40,643,144	40,841,291	41,039,446	41,238,409	41,449,307	41,342,005	
	Change	Beginning Balance	62,550	65,350	68,159	70,977	73,797	76,617	79,438	82,259	85,079	87,900	90,728	93,662	
		Depr Expense	2,800	2,809	2,818	2,820	2,821	2,821	2,821	2,821	2,821	2,828	2,934	3,033	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**65,350**	**68,159**	**70,977**	**73,797**	**76,617**	**79,438**	**82,259**	**85,079**	**87,900**	**90,728**	**93,662**	**96,695**	
Other	Border Winds Project														
		Plant													
		Beginning Balance	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	
		Reserve													
	Original	Remaining Life (Mos)	216	215	214	213	212	211	210	209	208	207	206	205	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	216	215	214	213	212	211	210	209	208	207	206	205	
		Net Salvage Rate	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	
	Original	Beginning Balance	79,395,757	80,366,122	81,336,487	82,306,852	83,277,216	84,247,581	85,217,946	86,188,311	87,158,675	88,129,040	89,099,405	90,069,770	
		Depr Expense	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	11,644,378
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	80,366,122	81,336,487	82,306,852	83,277,216	84,247,581	85,217,946	86,188,311	87,158,675	88,129,040	89,099,405	90,069,770	91,040,134	
	Proposed	Beginning Balance	79,660,943	80,642,411	81,623,879	82,605,348	83,586,816	84,568,284	85,549,752	86,531,221	87,512,689	88,494,157	89,475,625	90,457,094	
		Depr Expense	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	11,777,620
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	80,642,411	81,623,879	82,605,348	83,586,816	84,568,284	85,549,752	86,531,221	87,512,689	88,494,157	89,475,625	90,457,094	91,438,562	
	Change	Beginning Balance	265,185	276,289	287,393	298,496	309,600	320,703	331,807	342,910	354,014	365,117	376,221	387,324	
		Depr Expense	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**276,289**	**287,393**	**298,496**	**309,600**	**320,703**	**331,807**	**342,910**	**354,014**	**365,117**	**376,221**	**387,324**	**398,428**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Community WF														
		Plant													
		Beginning Balance	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	6,385,924	6,623,619	6,861,315	7,099,010	7,336,706	7,574,401	7,812,097	8,049,793	8,287,488	8,525,184	8,762,879	9,000,575	
		Depr Expense	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	2,852,347
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	(0)	-	0	-	(0)	-	-	-	(0)	
		Ending Balance	6,623,619	6,861,315	7,099,010	7,336,706	7,574,401	7,812,097	8,049,793	8,287,488	8,525,184	8,762,879	9,000,575	9,238,270	
	Proposed	Beginning Balance	6,385,924	6,623,619	6,861,315	7,099,010	7,336,706	7,574,401	7,812,097	8,049,793	8,287,488	8,525,184	8,762,879	9,000,575	
		Depr Expense	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	2,852,347
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	(0)	-	0	-	(0)	-	-	-	(0)	
		Ending Balance	6,623,619	6,861,315	7,099,010	7,336,706	7,574,401	7,812,097	8,049,793	8,287,488	8,525,184	8,762,879	9,000,575	9,238,270	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Community Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	24	24	24	24	24	24	24	24	24	24	24	23	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	24	24	24	24	24	24	24	24	24	24	23	23	
	Proposed	Beginning Balance	24	24	24	24	24	24	24	24	24	24	24	23	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	24	24	24	24	24	24	24	24	24	24	23	23	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2023												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Courtenay WF														
		Plant													
		Beginning Balance	283,098,396	283,112,254	283,127,025	283,150,526	283,191,509	283,359,160	283,395,658	283,433,304	283,510,778	283,586,445	283,882,360	284,083,052	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	13,859	14,770	23,502	40,983	167,651	36,498	37,646	77,475	75,666	295,915	200,692	338,870	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	283,112,254	283,127,025	283,150,526	283,191,509	283,359,160	283,395,658	283,433,304	283,510,778	283,586,445	283,882,360	284,083,052	284,421,922	
		Reserve													
	Original	Remaining Life (Mos)	227	226	225	224	223	222	221	220	219	218	217	216	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	227	226	225	224	223	222	221	220	219	218	217	216	
		Net Salvage Rate	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	
	Original	Beginning Balance	73,787,457	74,814,209	75,840,784	76,866,281	77,889,526	78,895,919	79,920,290	80,944,429	81,962,392	82,980,606	83,962,175	84,959,609	
		Depr Expense	1,028,117	1,028,192	1,028,294	1,028,468	1,029,038	1,029,600	1,029,807	1,030,131	1,030,566	1,031,634	1,033,073	1,034,639	12,361,560
		Cost of Removal	(1,365)	(1,617)	(2,797)	(5,222)	(22,645)	(5,229)	(5,668)	(12,168)	(12,352)	(50,066)	(35,639)	(55,557)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	0	(0)	0	0	0	-	0	(0)	0	0	
		Ending Balance	74,814,209	75,840,784	76,866,281	77,889,526	78,895,919	79,920,290	80,944,429	81,962,392	82,980,606	83,962,175	84,959,609	85,938,691	
	Proposed	Beginning Balance	74,299,231	75,347,425	76,395,442	77,442,383	78,487,076	79,514,925	80,560,761	81,606,368	82,645,803	83,685,497	84,688,561	85,707,513	
		Depr Expense	1,049,558	1,049,635	1,049,739	1,049,915	1,050,494	1,051,065	1,051,274	1,051,604	1,052,046	1,053,130	1,054,591	1,056,181	12,619,231
		Cost of Removal	(1,365)	(1,617)	(2,797)	(5,222)	(22,645)	(5,229)	(5,668)	(12,168)	(12,352)	(50,066)	(35,639)	(55,557)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	0	(0)	0	0	0	-	0	(0)	0	0	
		Ending Balance	75,347,425	76,395,442	77,442,383	78,487,076	79,514,925	80,560,761	81,606,368	82,645,803	83,685,497	84,688,561	85,707,513	86,708,137	
	Change	Beginning Balance	511,774	533,216	554,659	576,103	597,550	619,006	640,471	661,939	683,411	704,891	726,387	747,904	
		Depr Expense	21,442	21,443	21,444	21,447	21,456	21,465	21,468	21,473	21,480	21,496	21,517	21,541	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**533,216**	**554,659**	**576,103**	**597,550**	**619,006**	**640,471**	**661,939**	**683,411**	**704,891**	**726,387**	**747,904**	**769,445**	
Other	Courtenay Wind Rights														
		Plant													
		Beginning Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Reserve													
	Original	Remaining Life (Mos)	227	226	225	224	223	222	221	220	219	218	217	216	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	227	226	225	224	223	222	221	220	219	218	217	216	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	510,184	517,125	524,065	531,006	537,946	544,887	551,827	558,767	565,708	572,648	579,589	586,529	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	517,125	524,065	531,006	537,946	544,887	551,827	558,767	565,708	572,648	579,589	586,529	593,469	
	Proposed	Beginning Balance	510,184	517,125	524,065	531,006	537,946	544,887	551,827	558,767	565,708	572,648	579,589	586,529	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	517,125	524,065	531,006	537,946	544,887	551,827	558,767	565,708	572,648	579,589	586,529	593,469	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2023												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Crowned Ridge WF														
		Plant													
		Beginning Balance	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	
		Reserve													
	Original	Remaining Life (Mos)	275	274	273	272	271	270	269	268	267	266	265	264	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	275	274	273	272	271	270	269	268	267	266	265	264	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	27,963,228	29,117,362	30,271,495	31,425,628	32,579,762	33,733,895	34,888,028	36,042,162	37,196,295	38,350,428	39,504,561	40,658,695	
		Depr Expense	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	13,849,600
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	29,117,362	30,271,495	31,425,628	32,579,762	33,733,895	34,888,028	36,042,162	37,196,295	38,350,428	39,504,561	40,658,695	41,812,828	
	Proposed	Beginning Balance	27,963,228	29,117,362	30,271,495	31,425,628	32,579,762	33,733,895	34,888,028	36,042,162	37,196,295	38,350,428	39,504,561	40,658,695	
		Depr Expense	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	13,849,600
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	29,117,362	30,271,495	31,425,628	32,579,762	33,733,895	34,888,028	36,042,162	37,196,295	38,350,428	39,504,561	40,658,695	41,812,828	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Dakota Range WF														
		Plant													
		Beginning Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	
		Reserve													
	Original	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	288	287	286	285	284	283	282	281	280	279	278	277	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	17,910,838	19,337,800	20,764,762	22,191,724	23,618,686	25,045,648	26,472,610	27,899,572	29,326,534	30,753,495	32,180,457	33,607,419	
		Depr Expense	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	17,123,543
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,337,800	20,764,762	22,191,724	23,618,686	25,045,648	26,472,610	27,899,572	29,326,534	30,753,495	32,180,457	33,607,419	35,034,381	
	Proposed	Beginning Balance	17,910,838	19,337,800	20,764,762	22,191,724	23,618,686	25,045,648	26,472,610	27,899,572	29,326,534	30,753,495	32,180,457	33,607,419	
		Depr Expense	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	17,123,543
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	19,337,800	20,764,762	22,191,724	23,618,686	25,045,648	26,472,610	27,899,572	29,326,534	30,753,495	32,180,457	33,607,419	35,034,381	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Foxtail WF														
		Plant													
		Beginning Balance	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	
		Reserve													
	Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	
	Original	Beginning Balance	31,663,744	32,526,712	33,389,680	34,252,648	35,115,616	35,978,584	36,841,552	37,704,520	38,567,488	39,430,456	40,293,424	41,156,391	
		Depr Expense	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	10,355,615
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	0	0	-	0	0	(0)	0	-	0	(0)	
		Ending Balance	32,526,712	33,389,680	34,252,648	35,115,616	35,978,584	36,841,552	37,704,520	38,567,488	39,430,456	40,293,424	41,156,391	42,019,359	
	Proposed	Beginning Balance	31,783,257	32,651,207	33,519,158	34,387,108	35,255,059	36,123,010	36,990,960	37,858,911	38,726,862	39,594,812	40,462,763	41,330,714	
		Depr Expense	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	10,415,408
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	0	0	-	0	0	(0)	0	-	0	(0)	
		Ending Balance	32,651,207	33,519,158	34,387,108	35,255,059	36,123,010	36,990,960	37,858,911	38,726,862	39,594,812	40,462,763	41,330,714	42,198,664	
	Change	Beginning Balance	119,512	124,495	129,478	134,460	139,443	144,426	149,408	154,391	159,374	164,357	169,339	174,322	
		Depr Expense	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**124,495**	**129,478**	**134,460**	**139,443**	**144,426**	**149,408**	**154,391**	**159,374**	**164,357**	**169,339**	**174,322**	**179,305**	
Other	Foxtail Wind Rights														
		Plant													
		Beginning Balance	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Reserve													
	Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	20,076	20,672	21,268	21,863	22,459	23,055	23,651	24,247	24,842	25,438	26,034	26,630	
		Depr Expense	596	596	596	596	596	596	596	596	596	596	596	596	7,149
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	20,672	21,268	21,863	22,459	23,055	23,651	24,247	24,842	25,438	26,034	26,630	27,226	
	Proposed	Beginning Balance	20,076	20,672	21,268	21,863	22,459	23,055	23,651	24,247	24,842	25,438	26,034	26,630	
		Depr Expense	596	596	596	596	596	596	596	596	596	596	596	596	7,149
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	20,672	21,268	21,863	22,459	23,055	23,651	24,247	24,842	25,438	26,034	26,630	27,226	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Freeborn WF**														
		Plant													
		Beginning Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	
		Reserve													
	Original	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	281	280	279	278	277	276	275	274	273	272	271	270	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	23,348,932	24,552,857	25,756,783	26,960,708	28,164,633	29,368,559	30,572,484	31,776,410	32,980,335	34,184,260	35,388,186	36,592,111	
		Depr Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,105
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	0	(0)	-	-	(0)	-	0	-	(0)	
		Ending Balance	24,552,857	25,756,783	26,960,708	28,164,633	29,368,559	30,572,484	31,776,410	32,980,335	34,184,260	35,388,186	36,592,111	37,796,036	
	Proposed	Beginning Balance	23,348,932	24,552,857	25,756,783	26,960,708	28,164,633	29,368,559	30,572,484	31,776,410	32,980,335	34,184,260	35,388,186	36,592,111	
		Depr Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,105
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	0	(0)	-	-	(0)	-	0	-	(0)	
		Ending Balance	24,552,857	25,756,783	26,960,708	28,164,633	29,368,559	30,572,484	31,776,410	32,980,335	34,184,260	35,388,186	36,592,111	37,796,036	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	**Fuel Holders (Wind-to-Battery)**														
		Plant													
		Beginning Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Reserve													
	Original	Remaining Life (Mos)	12	11	10	9	8	7	6	5	4	3	2	1	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	3,833,533	3,858,147	3,882,762	3,907,376	3,931,990	3,956,604	3,981,218	4,005,832	4,030,446	4,055,060	4,079,674	4,104,288	
		Depr Expense	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	24,614	295,369
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	-	-	0	-	(0)	(0)	0	
		Ending Balance	3,858,147	3,882,762	3,907,376	3,931,990	3,956,604	3,981,218	4,005,832	4,030,446	4,055,060	4,079,674	4,104,288	4,128,902	
	Proposed	Beginning Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	-	-	0	-	(0)	(0)	0	
		Ending Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
	Change	Beginning Balance	295,369	270,755	246,141	221,527	196,913	172,298	147,684	123,070	98,456	73,842	49,228	24,614	
		Depr Expense	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	(24,614)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**270,755**	**246,141**	**221,527**	**196,913**	**172,298**	**147,684**	**123,070**	**98,456**	**73,842**	**49,228**	**24,614**	**(0)**	

Functional Class	Plant Name		January 2023	February	March	April	May	June	July	August	September	October	November	December	
Other	Grand Meadow WF														
		Plant													
		Beginning Balance	203,693,209	203,700,916	203,708,505	203,719,716	203,737,927	203,825,476	203,843,069	203,864,374	203,905,043	203,950,837	204,116,745	126,725,666	
		Retirements	-	-	-	-	-	-	-	-	-	-	(189,493,688)	-	
		Additions	7,707	7,590	11,211	18,211	87,548	17,594	21,305	40,669	45,794	165,908	112,102,609	520,141	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	203,700,916	203,708,505	203,719,716	203,737,927	203,825,476	203,843,069	203,864,374	203,905,043	203,950,837	204,116,745	126,725,666	127,245,806	
		Reserve													
	Original	Remaining Life (Mos)	131	130	129	128	127	126	125	124	123	122	121	120	
		Net Salvage Rate	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	
	Proposed	Remaining Life (Mos)	131	130	129	128	127	126	125	124	123	122	121	120	
		Net Salvage Rate	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	
	Original	Beginning Balance	120,727,195	121,532,298	122,337,490	123,142,377	123,946,644	124,743,836	125,549,198	126,354,346	127,157,711	127,961,941	128,756,499	(59,428,778)	
		Depr Expense	805,959	806,031	806,120	806,260	806,769	807,278	807,468	807,772	808,197	809,237	1,324,780	1,671,000	11,066,871
		Cost of Removal	(856)	(839)	(1,233)	(1,994)	(9,577)	(1,915)	(2,320)	(4,407)	(3,966)	(14,679)	(16,408)	(20,075)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	(189,493,688)	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	39	0	
		Ending Balance	121,532,298	122,337,490	123,142,377	123,946,644	124,743,836	125,549,198	126,354,346	127,157,711	127,961,941	128,756,499	(59,428,778)	(57,777,853)	
	Proposed	Beginning Balance	121,165,530	121,989,056	122,812,672	123,635,984	124,458,677	125,274,301	126,098,101	126,921,690	127,743,499	128,566,178	129,379,197	(58,781,124)	
		Depr Expense	824,382	824,455	824,545	824,687	825,201	825,716	825,908	826,216	826,646	827,698	1,349,736	1,680,418	11,285,608
		Cost of Removal	(856)	(839)	(1,233)	(1,994)	(9,577)	(1,915)	(2,320)	(4,407)	(3,966)	(14,679)	(16,408)	(20,075)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	(189,493,688)	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	39	0	
		Ending Balance	121,989,056	122,812,672	123,635,984	124,458,677	125,274,301	126,098,101	126,921,690	127,743,499	128,566,178	129,379,197	(58,781,124)	(57,120,781)	
	Change	Beginning Balance	438,334	456,758	475,181	493,606	512,033	530,465	548,904	567,344	585,788	604,237	622,698	647,653	
		Depr Expense	18,423	18,424	18,425	18,427	18,432	18,438	18,440	18,444	18,449	18,461	24,956	9,418	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**456,758**	**475,181**	**493,606**	**512,033**	**530,465**	**548,904**	**567,344**	**585,788**	**604,237**	**622,698**	**647,653**	**657,071**	
Other	Grand Meadow Wind Rights														
		Plant													
		Beginning Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Reserve													
	Original	Remaining Life (Mos)	131	130	129	128	127	126	125	124	123	122	121	120	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	131	130	129	128	127	126	125	124	123	122	121	120	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	5,448,778	5,488,653	5,528,529	5,568,404	5,608,280	5,648,155	5,688,030	5,727,906	5,767,781	5,807,656	5,847,532	5,887,407	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	(0)	0	-	-	-	0	(0)	-	-	(0)	
		Ending Balance	5,488,653	5,528,529	5,568,404	5,608,280	5,648,155	5,688,030	5,727,906	5,767,781	5,807,656	5,847,532	5,887,407	5,927,283	
	Proposed	Beginning Balance	5,448,778	5,488,653	5,528,529	5,568,404	5,608,280	5,648,155	5,688,030	5,727,906	5,767,781	5,807,656	5,847,532	5,887,407	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	-	(0)	0	-	-	-	0	(0)	-	-	(0)	
		Ending Balance	5,488,653	5,528,529	5,568,404	5,608,280	5,648,155	5,688,030	5,727,906	5,767,781	5,807,656	5,847,532	5,887,407	5,927,283	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		January 2023	February	March	April	May	June	July	August	September	October	November	December	
Other	High Bridge														
		Plant													
		Beginning Balance	413,195,026	413,201,947	413,209,175	421,798,278	428,266,906	428,825,185	428,851,631	428,877,254	428,933,887	429,259,762	432,124,505	432,689,788	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	6,921	7,228	8,589,103	6,468,628	558,279	26,446	25,623	56,633	325,875	2,864,743	565,284	288,197	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	413,201,947	413,209,175	421,798,278	428,266,906	428,825,185	428,851,631	428,877,254	428,933,887	429,259,762	432,124,505	432,689,788	432,977,985	
		Reserve													
	Original	Remaining Life (Mos)	305	304	303	302	301	300	299	298	297	296	295	294	
		Net Salvage Rate	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	
	Proposed	Remaining Life (Mos)	305	304	303	302	301	300	299	298	297	296	295	294	
		Net Salvage Rate	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	
	Original	Beginning Balance	127,968,224	128,950,808	129,933,417	130,930,701	131,953,777	132,988,848	133,137,659	134,099,726	135,139,340	136,179,625	137,225,391	138,235,000	
		Depr Expense	982,597	982,622	997,303	1,023,106	1,035,188	1,037,678	1,039,384	1,039,656	1,040,323	1,045,901	1,051,991	1,053,660	12,329,409
		Cost of Removal	(13)	(13)	(19)	(31)	(116)	(888,867)	(77,317)	(42)	(38)	(136)	(42,381)	(56,055)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	(0)	0	0	0	0	0	0	
		Ending Balance	128,950,808	129,933,417	130,930,701	131,953,777	132,988,848	133,137,659	134,099,726	135,139,340	136,179,625	137,225,391	138,235,000	139,232,605	
	Proposed	Beginning Balance	128,207,334	129,199,973	130,192,636	131,200,088	132,233,531	133,279,063	133,438,341	134,410,877	135,460,961	136,511,722	137,568,006	138,588,180	
		Depr Expense	992,651	992,676	1,007,471	1,033,473	1,045,648	1,048,146	1,049,853	1,050,126	1,050,798	1,056,420	1,062,555	1,064,237	12,454,055
		Cost of Removal	(13)	(13)	(19)	(31)	(116)	(888,867)	(77,317)	(42)	(38)	(136)	(42,381)	(56,055)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	(0)	0	0	0	0	0	0	
		Ending Balance	129,199,973	130,192,636	131,200,088	132,233,531	133,279,063	133,438,341	134,410,877	135,460,961	136,511,722	137,568,006	138,588,180	139,596,361	
	Change	Beginning Balance	239,111	249,165	259,219	269,387	279,754	290,214	300,682	311,152	321,622	332,097	342,615	353,180	
		Depr Expense	10,054	10,054	10,168	10,367	10,461	10,468	10,469	10,470	10,475	10,518	10,565	10,577	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**249,165**	**259,219**	**269,387**	**279,754**	**290,214**	**300,682**	**311,152**	**321,622**	**332,097**	**342,615**	**353,180**	**363,757**	
Other	Inver Hills														
		Plant													
		Beginning Balance	61,631,167	61,631,343	61,631,528	61,631,831	61,632,390	64,567,428	64,576,529	64,582,344	64,586,220	64,588,056	64,596,227	64,602,419	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	176	185	303	559	2,935,038	9,101	5,815	3,876	1,836	8,172	6,191	5,097	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	61,631,343	61,631,528	61,631,831	61,632,390	64,567,428	64,576,529	64,582,344	64,586,220	64,588,056	64,596,227	64,602,419	64,607,515	
		Reserve													
	Original	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	
	Proposed	Remaining Life (Mos)	48	47	46	45	44	43	42	41	40	39	38	37	
		Net Salvage Rate	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	
	Original	Beginning Balance	61,075,145	61,321,694	61,568,248	61,814,807	62,061,375	62,347,388	62,673,921	62,971,138	63,246,496	63,575,487	63,904,609	64,233,967	
		Depr Expense	246,555	246,560	246,566	246,577	286,042	326,541	327,107	328,257	329,002	329,155	329,379	329,560	3,571,300
		Cost of Removal	(3)	(3)	(4)	(7)	(26)	(5)	(29,887)	(52,895)	(8)	(30)	(18)	(12)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	
		Ending Balance	61,321,694	61,568,248	61,814,807	62,061,375	62,347,388	62,673,921	62,971,138	63,246,496	63,575,487	63,904,609	64,233,967	64,563,512	
	Proposed	Beginning Balance	61,294,249	61,550,358	61,806,471	62,062,589	62,318,716	62,614,656	62,951,492	63,259,014	63,544,678	63,883,976	64,223,406	64,563,075	
		Depr Expense	256,114	256,119	256,125	256,137	295,968	336,844	337,412	338,563	339,309	339,463	339,689	339,872	3,691,615
		Cost of Removal	(3)	(3)	(4)	(7)	(26)	(5)	(29,887)	(52,895)	(8)	(30)	(18)	(12)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	
		Ending Balance	61,550,358	61,806,471	62,062,589	62,318,716	62,614,656	62,951,492	63,259,014	63,544,678	63,883,976	64,223,406	64,563,075	64,902,932	
	Change	Beginning Balance	219,105	228,664	238,223	247,782	257,342	267,268	277,571	287,876	298,182	308,489	318,797	329,107	
		Depr Expense	9,559	9,559	9,559	9,559	9,926	10,303	10,305	10,306	10,307	10,308	10,310	10,312	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**228,664**	**238,223**	**247,782**	**257,342**	**267,268**	**277,571**	**287,876**	**298,182**	**308,489**	**318,797**	**329,107**	**339,420**	

Northern States Power Company
Other Production

Docket No. E002/GR-21-633
Exhibit___(MPM-1), Schedule 6
Page 100 of 122

Functional Class	Plant Name							2023							
			January	February	March	April	May	June	July	August	September	October	November	December	
Other	Jeffers WF														
		Plant													
		Beginning Balance	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	7,561,804	7,814,573	8,067,343	8,320,112	8,572,881	8,825,651	9,078,420	9,331,190	9,583,959	9,836,728	10,089,498	10,342,267	
		Depr Expense	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	3,033,233
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,814,573	8,067,343	8,320,112	8,572,881	8,825,651	9,078,420	9,331,190	9,583,959	9,836,728	10,089,498	10,342,267	10,595,037	
	Proposed	Beginning Balance	7,561,804	7,814,573	8,067,343	8,320,112	8,572,881	8,825,651	9,078,420	9,331,190	9,583,959	9,836,728	10,089,498	10,342,267	
		Depr Expense	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	3,033,233
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,814,573	8,067,343	8,320,112	8,572,881	8,825,651	9,078,420	9,331,190	9,583,959	9,836,728	10,089,498	10,342,267	10,595,037	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Jeffers Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	185	185	184	183	183	182	181	181	180	179	179	178	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	185	184	183	183	182	181	181	180	179	179	178	177	
	Proposed	Beginning Balance	185	185	184	183	183	182	181	181	180	179	179	178	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	185	184	183	183	182	181	181	180	179	179	178	177	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Lake Benton WF**														
		Plant													
		Beginning Balance	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	
		Reserve													
	Original	Remaining Life (Mos)	263	262	261	260	259	258	257	256	255	254	253	252	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	263	262	261	260	259	258	257	256	255	254	253	252	
		Net Salvage Rate	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	
	Original	Beginning Balance	21,617,583	22,200,788	22,783,992	23,367,196	23,950,401	24,533,605	25,116,810	25,700,014	26,283,219	26,866,423	27,449,627	28,032,832	
		Depr Expense	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	6,998,453
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	(0)	0	0	(0)	-	(0)	0	-	
		Ending Balance	22,200,788	22,783,992	23,367,196	23,950,401	24,533,605	25,116,810	25,700,014	26,283,219	26,866,423	27,449,627	28,032,832	28,616,036	
	Proposed	Beginning Balance	21,926,809	22,522,943	23,119,077	23,715,211	24,311,345	24,907,479	25,503,613	26,099,747	26,695,881	27,292,015	27,888,149	28,484,283	
		Depr Expense	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	7,153,607
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	-	(0)	0	0	(0)	-	(0)	0	-	
		Ending Balance	22,522,943	23,119,077	23,715,211	24,311,345	24,907,479	25,503,613	26,099,747	26,695,881	27,292,015	27,888,149	28,484,283	29,080,417	
	Change	Beginning Balance	309,226	322,156	335,085	348,015	360,944	373,874	386,803	399,733	412,662	425,592	438,521	451,451	
		Depr Expense	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**322,156**	**335,085**	**348,015**	**360,944**	**373,874**	**386,803**	**399,733**	**412,662**	**425,592**	**438,521**	**451,451**	**464,380**	
Other	**Lake Benton Wind Rights**														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	263	262	261	260	259	258	257	256	255	254	253	252	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	263	262	261	260	259	258	257	256	255	254	253	252	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Proposed	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2023												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Mower WF**														
		Plant													
		Beginning Balance	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	78,561,127	79,170,741	79,780,355	80,389,969	80,999,583	81,609,197	82,218,810	82,828,424	83,438,038	84,047,652	84,657,266	85,266,880	
		Depr Expense	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	7,315,367
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	-	(0)	(0)	-	(0)	(0)	-	(0)	(0)	
		Ending Balance	79,170,741	79,780,355	80,389,969	80,999,583	81,609,197	82,218,810	82,828,424	83,438,038	84,047,652	84,657,266	85,266,880	85,876,494	
	Proposed	Beginning Balance	78,561,127	79,170,741	79,780,355	80,389,969	80,999,583	81,609,197	82,218,810	82,828,424	83,438,038	84,047,652	84,657,266	85,266,880	
		Depr Expense	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	7,315,367
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	-	(0)	(0)	-	(0)	(0)	-	(0)	(0)	
		Ending Balance	79,170,741	79,780,355	80,389,969	80,999,583	81,609,197	82,218,810	82,828,424	83,438,038	84,047,652	84,657,266	85,266,880	85,876,494	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	**Mower Wind Rights**														
		Plant													
		Beginning Balance	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
		Reserve													
	Original	Remaining Life (Mos)	279	278	277	276	275	274	273	272	271	270	269	268	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	279	278	277	276	275	274	273	272	271	270	269	268	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	44,851	46,938	49,024	51,110	53,197	55,283	57,369	59,455	61,542	63,628	65,714	67,801	
		Depr Expense	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	25,036
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	(0)	0	0	(0)	-	-	-	-	(0)	0	
		Ending Balance	46,938	49,024	51,110	53,197	55,283	57,369	59,455	61,542	63,628	65,714	67,801	69,887	
	Proposed	Beginning Balance	44,851	46,938	49,024	51,110	53,197	55,283	57,369	59,455	61,542	63,628	65,714	67,801	
		Depr Expense	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	25,036
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	(0)	0	0	(0)	-	-	-	-	(0)	0	
		Ending Balance	46,938	49,024	51,110	53,197	55,283	57,369	59,455	61,542	63,628	65,714	67,801	69,887	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Nobles WF														
		Plant													
		Beginning Balance	284,611,671	285,290,479	285,866,420	286,826,292	286,850,625	286,887,161	287,792,551	287,902,086	287,928,142	287,953,617	287,993,405	288,025,324	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	678,807	575,941	959,872	24,332	36,536	905,390	109,536	26,055	25,475	39,788	31,920	28,076	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	285,290,479	285,866,420	286,826,292	286,850,625	286,887,161	287,792,551	287,902,086	287,928,142	287,953,617	287,993,405	288,025,324	288,053,400	
		Reserve													
	Original	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	
	Proposed	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Original	Beginning Balance	(202,809,068)	(199,552,163)	(196,290,934)	(193,024,493)	(189,754,830)	(186,486,505)	(183,213,149)	(179,936,159)	(176,659,041)	(173,381,657)	(170,105,813)	(166,828,702)	
		Depr Expense	3,257,144	3,261,464	3,266,786	3,270,221	3,270,443	3,273,780	3,277,393	3,277,882	3,278,073	3,278,321	3,278,596	3,278,826	39,268,928
		Cost of Removal	(239)	(234)	(345)	(557)	(2,117)	(423)	(402)	(764)	(688)	(2,476)	(1,486)	(1,003)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	(199,552,163)	(196,290,934)	(193,024,493)	(189,754,830)	(186,486,505)	(183,213,149)	(179,936,159)	(176,659,041)	(173,381,657)	(170,105,813)	(166,828,702)	(163,550,880)	
	Proposed	Beginning Balance	(201,061,092)	(197,769,505)	(194,473,491)	(191,172,141)	(187,867,487)	(184,564,165)	(181,255,735)	(177,943,585)	(174,631,297)	(171,318,737)	(168,007,712)	(164,695,414)	
		Depr Expense	3,291,827	3,296,248	3,301,696	3,305,211	3,305,439	3,308,854	3,312,552	3,313,053	3,313,248	3,313,502	3,313,784	3,314,018	39,689,432
		Cost of Removal	(239)	(234)	(345)	(557)	(2,117)	(423)	(402)	(764)	(688)	(2,476)	(1,486)	(1,003)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	(197,769,505)	(194,473,491)	(191,172,141)	(187,867,487)	(184,564,165)	(181,255,735)	(177,943,585)	(174,631,297)	(171,318,737)	(168,007,712)	(164,695,414)	(161,382,399)	
	Change	Beginning Balance	1,747,976	1,782,659	1,817,443	1,852,353	1,887,344	1,922,340	1,957,414	1,992,574	2,027,745	2,062,920	2,098,101	2,133,288	
		Depr Expense	34,683	34,784	34,910	34,991	34,996	35,074	35,160	35,171	35,175	35,181	35,187	35,192	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,782,659**	**1,817,443**	**1,852,353**	**1,887,344**	**1,922,340**	**1,957,414**	**1,992,574**	**2,027,745**	**2,062,920**	**2,098,101**	**2,133,288**	**2,168,480**	
Other	Nobles Wind Rights														
		Plant													
		Beginning Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Reserve													
	Original	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	155	154	153	152	151	150	149	148	147	146	145	144	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	1,863,444	1,876,485	1,889,526	1,902,567	1,915,609	1,928,650	1,941,691	1,954,732	1,967,774	1,980,815	1,993,856	2,006,897	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	(0)	0	-	-	0	(0)	0	
		Ending Balance	1,876,485	1,889,526	1,902,567	1,915,609	1,928,650	1,941,691	1,954,732	1,967,774	1,980,815	1,993,856	2,006,897	2,019,938	
	Proposed	Beginning Balance	1,863,444	1,876,485	1,889,526	1,902,567	1,915,609	1,928,650	1,941,691	1,954,732	1,967,774	1,980,815	1,993,856	2,006,897	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	0	-	-	(0)	0	-	-	0	(0)	0	
		Ending Balance	1,876,485	1,889,526	1,902,567	1,915,609	1,928,650	1,941,691	1,954,732	1,967,774	1,980,815	1,993,856	2,006,897	2,019,938	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2023 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Pleasant Valley WF														
		Plant													
		Beginning Balance	334,831,596	334,844,888	334,859,231	334,882,298	334,922,899	335,090,397	335,127,190	335,165,444	335,244,729	335,322,685	335,629,479	335,839,329	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	13,293	14,343	23,066	40,602	167,498	36,793	38,253	79,286	77,955	306,794	209,850	274,065	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	334,844,888	334,859,231	334,882,298	334,922,899	335,090,397	335,127,190	335,165,444	335,244,729	335,322,685	335,629,479	335,839,329	336,113,394	
		Reserve													
	Original	Remaining Life (Mos)	216	215	214	213	212	211	210	209	208	207	206	205	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	216	215	214	213	212	211	210	209	208	207	206	205	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Original	Beginning Balance	101,583,589	102,794,179	104,004,781	105,214,833	106,423,756	107,623,799	108,834,216	110,044,768	111,252,720	112,461,264	113,654,769	114,856,724	
		Depr Expense	1,211,650	1,211,725	1,211,827	1,212,000	1,212,569	1,213,131	1,213,338	1,213,663	1,214,100	1,215,174	1,216,623	1,218,001	14,563,802
		Cost of Removal	(1,060)	(1,122)	(1,775)	(3,077)	(12,527)	(2,714)	(2,786)	(5,711)	(5,556)	(21,669)	(14,668)	(25,276)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	(0)	-	0	
		Ending Balance	102,794,179	104,004,781	105,214,833	106,423,756	107,623,799	108,834,216	110,044,768	111,252,720	112,461,264	113,654,769	114,856,724	116,049,450	
	Proposed	Beginning Balance	102,649,206	103,904,469	105,159,746	106,414,475	107,668,080	108,912,820	110,167,950	111,423,220	112,675,901	113,929,185	115,167,459	116,414,224	
		Depr Expense	1,256,322	1,256,399	1,256,504	1,256,682	1,257,267	1,257,844	1,258,057	1,258,391	1,258,840	1,259,944	1,261,433	1,262,849	15,100,532
		Cost of Removal	(1,060)	(1,122)	(1,775)	(3,077)	(12,527)	(2,714)	(2,786)	(5,711)	(5,556)	(21,669)	(14,668)	(25,276)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	(0)	-	0	
		Ending Balance	103,904,469	105,159,746	106,414,475	107,668,080	108,912,820	110,167,950	111,423,220	112,675,901	113,929,185	115,167,459	116,414,224	117,651,797	
	Change	Beginning Balance	1,065,618	1,110,290	1,154,964	1,199,641	1,244,323	1,289,021	1,333,734	1,378,453	1,423,180	1,467,920	1,512,690	1,557,500	
		Depr Expense	44,672	44,674	44,677	44,682	44,698	44,713	44,719	44,728	44,740	44,770	44,810	44,848	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,110,290**	**1,154,964**	**1,199,641**	**1,244,323**	**1,289,021**	**1,333,734**	**1,378,453**	**1,423,180**	**1,467,920**	**1,512,690**	**1,557,500**	**1,602,347**	
Other	Riverside														
		Plant													
		Beginning Balance	347,433,930	347,450,517	347,462,428	347,481,176	347,514,303	347,722,255	347,754,859	347,790,266	347,869,548	347,956,605	348,447,734	349,139,868	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	16,587	11,912	18,748	33,127	207,951	32,605	35,407	79,282	87,056	491,130	692,133	240,293	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	347,450,517	347,462,428	347,481,176	347,514,303	347,722,255	347,754,859	347,790,266	347,869,548	347,956,605	348,447,734	349,139,868	349,380,161	
		Reserve													
	Original	Remaining Life (Mos)	315	314	313	312	311	310	309	308	307	306	305	304	
		Net Salvage Rate	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	
	Proposed	Remaining Life (Mos)	315	314	313	312	311	310	309	308	307	306	305	304	
		Net Salvage Rate	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	
	Original	Beginning Balance	119,994,980	120,653,578	121,500,821	122,348,072	123,195,327	124,042,358	124,888,540	125,736,856	126,585,228	127,433,935	128,282,942	129,134,528	
		Depr Expense	846,992	847,342	847,397	847,490	847,924	848,360	848,487	848,695	848,997	850,051	852,213	853,962	10,187,911
		Cost of Removal	(188,393)	(99)	(145)	(235)	(892)	(2,178)	(169)	(322)	(290)	(1,043)	(626)	(25,422)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	120,653,578	121,500,821	122,348,072	123,195,327	124,042,358	124,888,540	125,736,856	126,585,228	127,433,935	128,282,942	129,134,528	129,963,068	
	Proposed	Beginning Balance	120,446,202	121,124,325	121,991,093	122,857,870	123,724,653	124,591,219	125,456,943	126,324,804	127,192,724	128,060,984	128,929,563	129,800,757	
		Depr Expense	866,516	866,868	866,924	867,018	867,459	867,903	868,031	868,243	868,551	869,622	871,821	873,600	10,422,555
		Cost of Removal	(188,393)	(99)	(145)	(235)	(892)	(2,178)	(169)	(322)	(290)	(1,043)	(626)	(25,422)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	121,124,325	121,991,093	122,857,870	123,724,653	124,591,219	125,456,943	126,324,804	127,192,724	128,060,984	128,929,563	129,800,757	130,648,934	
	Change	Beginning Balance	451,222	470,747	490,272	509,798	529,326	548,861	568,403	587,948	607,496	627,049	646,621	666,229	
		Depr Expense	19,524	19,525	19,526	19,528	19,535	19,542	19,545	19,548	19,553	19,571	19,608	19,637	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**470,747**	**490,272**	**509,798**	**529,326**	**548,861**	**568,403**	**587,948**	**607,496**	**627,049**	**646,621**	**666,229**	**685,866**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 2 & 3														
		Plant													
		Beginning Balance	101,038,722	101,044,531	101,050,651	101,056,201	101,124,763	101,195,887	101,216,505	101,232,403	101,328,273	101,400,399	101,923,874	102,116,761	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	5,809	6,120	5,550	68,562	71,124	20,618	15,899	95,870	72,126	523,474	192,888	166,218	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	101,044,531	101,050,651	101,056,201	101,124,763	101,195,887	101,216,505	101,232,403	101,328,273	101,400,399	101,923,874	102,116,761	102,282,979	
		Reserve													
	Original	Remaining Life (Mos)	204	203	202	201	200	199	198	197	196	195	194	193	
		Net Salvage Rate	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	-9.6%	
	Proposed	Remaining Life (Mos)	204	203	202	201	200	199	198	197	196	195	194	193	
		Net Salvage Rate	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	-11.2%	
	Original	Beginning Balance	71,413,277	71,605,936	71,793,642	71,986,341	72,179,148	72,371,603	72,550,150	72,743,845	72,937,688	73,132,037	73,317,282	73,515,022	
		Depr Expense	192,786	192,831	192,876	193,079	193,465	193,759	193,899	194,211	194,683	196,386	198,440	199,508	2,335,924
		Cost of Removal	(113)	(5,111)	(163)	(264)	(1,002)	(15,200)	(190)	(362)	(325)	(11,172)	(703)	(17,974)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(14)	(14)	(14)	(9)	(9)	(12)	(13)	(6)	(8)	31	3	1	
		Ending Balance	71,605,936	71,793,642	71,986,341	72,179,148	72,371,603	72,550,150	72,743,845	72,937,688	73,132,037	73,317,282	73,515,022	73,696,556	
	Proposed	Beginning Balance	71,632,160	71,831,671	72,026,230	72,225,781	72,425,444	72,624,760	72,810,172	73,010,734	73,211,448	73,412,675	73,604,822	73,809,494	
		Depr Expense	199,638	199,684	199,729	199,935	200,327	200,624	200,765	201,082	201,561	203,288	205,372	206,455	2,418,459
		Cost of Removal	(113)	(5,111)	(163)	(264)	(1,002)	(15,200)	(190)	(362)	(325)	(11,172)	(703)	(17,974)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(14)	(14)	(14)	(9)	(9)	(12)	(13)	(6)	(8)	31	3	1	
		Ending Balance	71,831,671	72,026,230	72,225,781	72,425,444	72,624,760	72,810,172	73,010,734	73,211,448	73,412,675	73,604,822	73,809,494	73,997,975	
	Change	Beginning Balance	218,883	225,735	232,588	239,440	246,296	253,157	260,022	266,889	273,760	280,638	287,540	294,472	
		Depr Expense	6,852	6,852	6,853	6,856	6,861	6,865	6,867	6,871	6,878	6,902	6,932	6,947	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**225,735**	**232,588**	**239,440**	**246,296**	**253,157**	**260,022**	**266,889**	**273,760**	**280,638**	**287,540**	**294,472**	**301,419**	
Other	Angus Anson Unit 2 & 3 - FERC 341														
		Plant													
		Beginning Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	7,614,500	
		Reserve													
	Original	Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	5,886,479	5,895,129	5,903,779	5,912,429	5,921,078	5,929,728	5,938,378	5,947,028	5,955,678	5,964,327	5,972,977	5,981,627	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,895,129	5,903,779	5,912,429	5,921,078	5,929,728	5,938,378	5,947,028	5,955,678	5,964,327	5,972,977	5,981,627	5,990,277	
	Proposed	Beginning Balance	5,886,479	5,895,129	5,903,779	5,912,429	5,921,078	5,929,728	5,938,378	5,947,028	5,955,678	5,964,327	5,972,977	5,981,627	
		Depr Expense	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	8,650	103,796
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
		Ending Balance	5,895,129	5,903,779	5,912,429	5,921,078	5,929,728	5,938,378	5,947,028	5,955,678	5,964,327	5,972,977	5,981,627	5,990,277	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Angus Anson Unit 4														
		Plant													
		Beginning Balance	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	47,565,807	
		Reserve													
	Original	Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Proposed	Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	-6.5%	
	Original	Beginning Balance	21,038,595	21,153,846	21,269,096	21,384,347	21,499,597	21,614,848	21,730,098	21,845,348	21,960,599	22,075,849	22,191,099	22,306,350	
		Depr Expense	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	1,382,987
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	2	2	2	2	1	1	1	1	1	1	1	1	
		Ending Balance	21,153,846	21,269,096	21,384,347	21,499,597	21,614,848	21,730,098	21,845,348	21,960,599	22,075,849	22,191,099	22,306,350	22,421,600	
	Proposed	Beginning Balance	21,038,595	21,153,846	21,269,096	21,384,347	21,499,597	21,614,848	21,730,098	21,845,348	21,960,599	22,075,849	22,191,099	22,306,350	
		Depr Expense	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	115,249	1,382,987
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	2	2	2	2	1	1	1	1	1	1	1	1	
		Ending Balance	21,153,846	21,269,096	21,384,347	21,499,597	21,614,848	21,730,098	21,845,348	21,960,599	22,075,849	22,191,099	22,306,350	22,421,600	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Black Dog Unit 5														
		Plant													
		Beginning Balance	226,267,196	226,305,574	226,316,362	226,334,547	226,369,300	226,901,853	227,015,575	229,609,707	229,976,614	232,979,028	234,581,062	239,019,790	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	38,378	10,788	18,184	34,753	532,552	113,723	2,594,131	366,907	3,002,414	1,602,034	4,438,727	695,228	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	226,305,574	226,316,362	226,334,547	226,369,300	226,901,853	227,015,575	229,609,707	229,976,614	232,979,028	234,581,062	239,019,790	239,715,017	
		Reserve													
	Original	Remaining Life (Mos)	96	95	94	93	92	91	90	89	88	87	86	85	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	96	95	94	93	92	91	90	89	88	87	86	85	
		Net Salvage Rate	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	-7.2%	
	Original	Beginning Balance	139,390,488	140,537,508	141,711,959	125,432,717	126,795,329	128,161,369	129,531,373	130,886,359	132,292,008	133,619,553	134,714,241	136,215,180	
		Depr Expense	1,174,021	1,174,452	1,267,963	1,362,616	1,366,051	1,370,007	1,386,943	1,405,654	1,427,549	1,459,700	1,500,947	1,535,237	16,431,141
		Cost of Removal	(27,001)	(1)	(17,547,910)	(3)	(10)	(2)	(31,957)	(4)	(100,003)	(365,012)	(7)	(110,005)	
		Salvage	-	-	647	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	58	(1)	(1)	(1)	(1)	(1)	(1)	0	(1)	(1)	
		Ending Balance	140,537,508	141,711,959	125,432,717	126,795,329	128,161,369	129,531,373	130,886,359	132,292,008	133,619,553	134,714,241	136,215,180	137,640,411	
	Proposed	Beginning Balance	136,982,685	138,055,787	139,156,307	122,803,129	124,091,793	125,383,755	126,679,532	127,959,659	129,289,751	130,540,934	131,558,150	132,980,141	
		Depr Expense	1,100,102	1,100,522	1,194,027	1,288,668	1,291,973	1,295,780	1,312,084	1,330,097	1,351,187	1,382,227	1,421,999	1,455,020	15,523,687
		Cost of Removal	(27,001)	(1)	(17,547,910)	(3)	(10)	(2)	(31,957)	(4)	(100,003)	(365,012)	(7)	(110,005)	
		Salvage	-	-	647	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	58	(1)	(1)	(1)	(1)	(1)	(1)	0	(1)	(1)	
		Ending Balance	138,055,787	139,156,307	122,803,129	124,091,793	125,383,755	126,679,532	127,959,659	129,289,751	130,540,934	131,558,150	132,980,141	134,325,155	
	Change	Beginning Balance	(2,407,803)	(2,481,722)	(2,555,652)	(2,629,588)	(2,703,536)	(2,777,614)	(2,851,841)	(2,926,700)	(3,002,257)	(3,078,619)	(3,156,092)	(3,235,040)	
		Depr Expense	(73,919)	(73,930)	(73,936)	(73,948)	(74,078)	(74,227)	(74,859)	(75,557)	(76,361)	(77,473)	(78,948)	(80,216)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(2,481,722)**	**(2,555,652)**	**(2,629,588)**	**(2,703,536)**	**(2,777,614)**	**(2,851,841)**	**(2,926,700)**	**(3,002,257)**	**(3,078,619)**	**(3,156,092)**	**(3,235,040)**	**(3,315,256)**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Black Dog Unit 5 FERC 341														
		Plant													
		Beginning Balance	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	43,238,548	
		Reserve													
	Original	Remaining Life (Mos)	411	410	409	408	407	406	405	404	403	402	401	400	
		Net Salvage Rate	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	-11.4%	
	Proposed	Remaining Life (Mos)	411	410	409	408	407	406	405	404	403	402	401	400	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	29,133,478	29,179,797	29,226,115	29,272,434	29,318,752	29,365,070	29,411,389	29,457,707	29,504,025	29,550,343	29,596,661	29,642,980	
		Depr Expense	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	46,312	555,744
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	6	6	6	6	6	6	6	6	6	6	6	6	
		Ending Balance	29,179,797	29,226,115	29,272,434	29,318,752	29,365,070	29,411,389	29,457,707	29,504,025	29,550,343	29,596,661	29,642,980	29,689,298	
	Proposed	Beginning Balance	29,095,172	29,140,427	29,185,681	29,230,935	29,276,190	29,321,444	29,366,698	29,411,952	29,457,207	29,502,461	29,547,715	29,592,969	
		Depr Expense	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	45,248	542,975
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	6	6	6	6	6	6	6	6	6	6	6	6	
		Ending Balance	29,140,427	29,185,681	29,230,935	29,276,190	29,321,444	29,366,698	29,411,952	29,457,207	29,502,461	29,547,715	29,592,969	29,638,223	
	Change	Beginning Balance	(38,306)	(39,370)	(40,434)	(41,498)	(42,562)	(43,626)	(44,690)	(45,754)	(46,818)	(47,883)	(48,947)	(50,011)	
		Depr Expense	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	(1,064)	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(39,370)**	**(40,434)**	**(41,498)**	**(42,562)**	**(43,626)**	**(44,690)**	**(45,754)**	**(46,818)**	**(47,883)**	**(48,947)**	**(50,011)**	**(51,075)**	
Other	Black Dog Unit 6														
		Plant													
		Beginning Balance	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	102,878,893	
		Reserve													
	Original	Remaining Life (Mos)	411	410	409	408	407	406	405	404	403	402	401	400	
		Net Salvage Rate	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	
	Proposed	Remaining Life (Mos)	411	410	409	408	407	406	405	404	403	402	401	400	
		Net Salvage Rate	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	-10.3%	
	Original	Beginning Balance	23,337,289	23,543,336	23,749,384	23,955,431	24,161,479	24,367,526	24,573,574	24,779,621	24,985,669	25,191,716	25,397,764	25,603,811	
		Depr Expense	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	206,048	2,472,571
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	23,543,336	23,749,384	23,955,431	24,161,479	24,367,526	24,573,574	24,779,621	24,985,669	25,191,716	25,397,764	25,603,811	25,809,859	
	Proposed	Beginning Balance	23,775,632	23,993,880	24,212,127	24,430,375	24,648,622	24,866,870	25,085,118	25,303,365	25,521,613	25,739,860	25,958,108	26,176,355	
		Depr Expense	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	218,248	2,618,972
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	23,993,880	24,212,127	24,430,375	24,648,622	24,866,870	25,085,118	25,303,365	25,521,613	25,739,860	25,958,108	26,176,355	26,394,603	
	Change	Beginning Balance	438,343	450,543	462,743	474,944	487,144	499,344	511,544	523,744	535,944	548,144	560,344	572,544	
		Depr Expense	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	12,200	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**450,543**	**462,743**	**474,944**	**487,144**	**499,344**	**511,544**	**523,744**	**535,944**	**548,144**	**560,344**	**572,544**	**584,744**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blazing Star I WF														
		Plant													
		Beginning Balance	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	308,190,681	
		Reserve													
	Original	Remaining Life (Mos)	256	255	254	253	252	251	250	249	248	247	246	245	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	256	255	254	253	252	251	250	249	248	247	246	245	
		Net Salvage Rate	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	-11.6%	
	Original	Beginning Balance	49,404,054	50,517,268	51,630,482	52,743,696	53,856,910	54,970,125	56,083,339	57,196,553	58,309,767	59,422,981	60,536,196	61,649,410	
		Depr Expense	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	1,113,214	13,358,570
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	(0)	0	(0)	-	(0)	-	(0)	-	(0)	
		Ending Balance	50,517,268	51,630,482	52,743,696	53,856,910	54,970,125	56,083,339	57,196,553	58,309,767	59,422,981	60,536,196	61,649,410	62,762,624	
	Proposed	Beginning Balance	50,580,797	51,726,734	52,872,672	54,018,609	55,164,547	56,310,484	57,456,422	58,602,359	59,748,297	60,894,234	62,040,172	63,186,109	
		Depr Expense	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	1,145,938	13,751,250
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	(0)	0	(0)	-	(0)	-	(0)	-	(0)	
		Ending Balance	51,726,734	52,872,672	54,018,609	55,164,547	56,310,484	57,456,422	58,602,359	59,748,297	60,894,234	62,040,172	63,186,109	64,332,047	
	Change	Beginning Balance	1,176,743	1,209,466	1,242,190	1,274,913	1,307,636	1,340,360	1,373,083	1,405,806	1,438,530	1,471,253	1,503,976	1,536,699	
		Depr Expense	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	32,723	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,209,466**	**1,242,190**	**1,274,913**	**1,307,636**	**1,340,360**	**1,373,083**	**1,405,806**	**1,438,530**	**1,471,253**	**1,503,976**	**1,536,699**	**1,569,423**	
Other	Blazing Star II WF														
		Plant													
		Beginning Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	
		Reserve													
	Original	Remaining Life (Mos)	265	264	263	262	261	260	259	258	257	256	255	254	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	265	264	263	262	261	260	259	258	257	256	255	254	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	44,084,717	45,330,862	46,577,008	47,823,153	49,069,298	50,315,444	51,561,589	52,807,735	54,053,880	55,300,025	56,546,171	57,792,316	
		Depr Expense	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	14,953,745
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	-	-	-	-	-	-	-	-	-	0	
		Ending Balance	45,330,862	46,577,008	47,823,153	49,069,298	50,315,444	51,561,589	52,807,735	54,053,880	55,300,025	56,546,171	57,792,316	59,038,462	
	Proposed	Beginning Balance	44,084,717	45,330,862	46,577,008	47,823,153	49,069,298	50,315,444	51,561,589	52,807,735	54,053,880	55,300,025	56,546,171	57,792,316	
		Depr Expense	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	1,246,145	14,953,745
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	-	-	-	-	-	-	-	-	-	0	
		Ending Balance	45,330,862	46,577,008	47,823,153	49,069,298	50,315,444	51,561,589	52,807,735	54,053,880	55,300,025	56,546,171	57,792,316	59,038,462	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 1 thru 4														
		Plant													
		Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Reserve													
Original		Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	-22.9%	
Proposed		Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	-30.6%	
Original		Beginning Balance	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	5,646,930	
Proposed		Beginning Balance	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	7,545,626	
Change		Beginning Balance	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	1,898,696	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	**1,898,696**	
Other	Blue Lake Units 1 thru 4 - FERC 341														
		Plant													
		Beginning Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	1,153,723	
		Reserve													
Original		Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
Proposed		Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
Original		Beginning Balance	1,113,117	1,113,800	1,114,483	1,115,167	1,115,850	1,116,533	1,117,216	1,117,900	1,118,583	1,119,266	1,119,949	1,120,633	
		Depr Expense	683	683	683	683	683	683	683	683	683	683	683	683	8,199
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	0	(0)	-	-	(0)	(0)	-	-	-	(0)	
		Ending Balance	1,113,800	1,114,483	1,115,167	1,115,850	1,116,533	1,117,216	1,117,900	1,118,583	1,119,266	1,119,949	1,120,633	1,121,316	
Proposed		Beginning Balance	1,114,535	1,115,257	1,115,980	1,116,703	1,117,425	1,118,148	1,118,870	1,119,593	1,120,316	1,121,038	1,121,761	1,122,483	
		Depr Expense	723	723	723	723	723	723	723	723	723	723	723	723	8,671
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	0	(0)	-	-	(0)	(0)	-	-	-	(0)	
		Ending Balance	1,115,257	1,115,980	1,116,703	1,117,425	1,118,148	1,118,870	1,119,593	1,120,316	1,121,038	1,121,761	1,122,483	1,123,206	
Change		Beginning Balance	1,418	1,457	1,496	1,536	1,575	1,615	1,654	1,693	1,733	1,772	1,811	1,851	
		Depr Expense	39	39	39	39	39	39	39	39	39	39	39	39	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,457**	**1,496**	**1,536**	**1,575**	**1,615**	**1,654**	**1,693**	**1,733**	**1,772**	**1,811**	**1,851**	**1,890**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Blue Lake Units 7 & 8														
		Plant													
		Beginning Balance	87,618,707	87,618,884	87,619,170	87,619,853	87,621,564	87,631,101	87,633,919	87,637,682	87,647,495	87,659,827	87,983,066	93,298,207	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	177	287	683	1,711	9,537	2,819	3,762	9,813	12,332	323,239	5,315,141	68,585	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	87,618,884	87,619,170	87,619,853	87,621,564	87,631,101	87,633,919	87,637,682	87,647,495	87,659,827	87,983,066	93,298,207	93,366,793	
		Reserve													
	Original	Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Proposed	Remaining Life (Mos)	257	256	255	254	253	252	251	250	249	248	247	246	
		Net Salvage Rate	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	-12.7%	
	Original	Beginning Balance	41,245,310	41,465,641	41,685,972	41,906,306	42,126,645	42,347,007	42,567,399	42,787,805	43,008,240	43,228,726	43,449,965	43,683,955	
		Depr Expense	220,330	220,331	220,333	220,339	220,364	220,391	220,406	220,436	220,486	221,241	233,990	246,842	2,685,489
		Cost of Removal	(0)	(0)	(0)	(1)	(2)	(0)	(0)	(1)	(1)	(3)	(2)	(309,501)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	41,465,641	41,685,972	41,906,306	42,126,645	42,347,007	42,567,399	42,787,805	43,008,240	43,228,726	43,449,965	43,683,955	43,621,297	
	Proposed	Beginning Balance	41,342,005	41,565,369	41,788,734	42,012,101	42,235,473	42,458,868	42,682,293	42,905,733	43,129,203	43,352,723	43,577,003	43,814,148	
		Depr Expense	223,363	223,364	223,366	223,372	223,397	223,424	223,439	223,470	223,520	224,282	237,146	250,107	2,722,252
		Cost of Removal	(0)	(0)	(0)	(1)	(2)	(0)	(0)	(1)	(1)	(3)	(2)	(309,501)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	1	1	1	1	1	1	1	1	1	1	1	1	
		Ending Balance	41,565,369	41,788,734	42,012,101	42,235,473	42,458,868	42,682,293	42,905,733	43,129,203	43,352,723	43,577,003	43,814,148	43,754,755	
	Change	Beginning Balance	96,695	99,728	102,761	105,794	108,827	111,861	114,894	117,928	120,962	123,996	127,038	130,193	
		Depr Expense	3,033	3,033	3,033	3,033	3,033	3,034	3,034	3,034	3,034	3,041	3,155	3,265	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**99,728**	**102,761**	**105,794**	**108,827**	**111,861**	**114,894**	**117,928**	**120,962**	**123,996**	**127,038**	**130,193**	**133,458**	
Other	Border Winds Project														
		Plant													
		Beginning Balance	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	266,354,430	
		Reserve													
	Original	Remaining Life (Mos)	204	203	202	201	200	199	198	197	196	195	194	193	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	204	203	202	201	200	199	198	197	196	195	194	193	
		Net Salvage Rate	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	-9.5%	
	Original	Beginning Balance	91,040,134	92,010,499	92,980,864	93,951,229	94,921,593	95,891,958	96,862,323	97,832,688	98,803,052	99,773,417	100,743,782	101,714,147	
		Depr Expense	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	970,365	11,644,378
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	92,010,499	92,980,864	93,951,229	94,921,593	95,891,958	96,862,323	97,832,688	98,803,052	99,773,417	100,743,782	101,714,147	102,684,512	
	Proposed	Beginning Balance	91,438,562	92,420,030	93,401,499	94,382,967	95,364,435	96,345,903	97,327,372	98,308,840	99,290,308	100,271,777	101,253,245	102,234,713	
		Depr Expense	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	981,468	11,777,620
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Ending Balance	92,420,030	93,401,499	94,382,967	95,364,435	96,345,903	97,327,372	98,308,840	99,290,308	100,271,777	101,253,245	102,234,713	103,216,181	
	Change	Beginning Balance	398,428	409,531	420,635	431,738	442,842	453,945	465,049	476,152	487,256	498,359	509,463	520,566	
		Depr Expense	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	11,104	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**409,531**	**420,635**	**431,738**	**442,842**	**453,945**	**465,049**	**476,152**	**487,256**	**498,359**	**509,463**	**520,566**	**531,670**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Community WF														
		Plant													
		Beginning Balance	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	65,149,231	
		Reserve													
	Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	9,238,270	9,475,966	9,713,662	9,951,357	10,189,053	10,426,748	10,664,444	10,902,139	11,139,835	11,377,531	11,615,226	11,852,922	
		Depr Expense	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	2,852,347
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	(0)	-	-	-	(0)	0	-	0	(0)	-	
		Ending Balance	9,475,966	9,713,662	9,951,357	10,189,053	10,426,748	10,664,444	10,902,139	11,139,835	11,377,531	11,615,226	11,852,922	12,090,617	
	Proposed	Beginning Balance	9,238,270	9,475,966	9,713,662	9,951,357	10,189,053	10,426,748	10,664,444	10,902,139	11,139,835	11,377,531	11,615,226	11,852,922	
		Depr Expense	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	237,696	2,852,347
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	(0)	-	-	-	(0)	0	-	0	(0)	-	
		Ending Balance	9,475,966	9,713,662	9,951,357	10,189,053	10,426,748	10,664,444	10,902,139	11,139,835	11,377,531	11,615,226	11,852,922	12,090,617	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Community Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	23	23	23	23	23	23	23	23	23	23	22	22	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	23	23	23	23	23	23	23	23	23	22	22	22	
	Proposed	Beginning Balance	23	23	23	23	23	23	23	23	23	23	22	22	
		Depr Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	23	23	23	23	23	23	23	23	23	22	22	22	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Courtenay WF**														
		Plant													
		Beginning Balance	284,421,922	284,432,314	284,444,616	284,465,890	284,505,620	284,677,941	284,717,742	284,760,906	284,853,642	284,947,837	285,329,627	285,600,947	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	10,392	12,302	21,274	39,730	172,322	39,801	43,164	92,736	94,195	381,789	271,320	230,345	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	284,432,314	284,444,616	284,465,890	284,505,620	284,677,941	284,717,742	284,760,906	284,853,642	284,947,837	285,329,627	285,600,947	285,831,292	
		Reserve													
	Original	Remaining Life (Mos)	215	214	213	212	211	210	209	208	207	206	205	204	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	215	214	213	212	211	210	209	208	207	206	205	204	
		Net Salvage Rate	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	-10.4%	
	Original	Beginning Balance	85,938,691	86,972,849	88,006,964	89,040,215	90,071,714	91,089,874	92,123,032	93,156,283	94,185,477	95,215,377	96,221,939	97,240,868	
		Depr Expense	1,035,653	1,035,718	1,035,813	1,035,986	1,036,586	1,037,187	1,037,422	1,037,807	1,038,338	1,039,693	1,041,557	1,042,992	12,454,753
		Cost of Removal	(1,496)	(1,603)	(2,563)	(4,487)	(18,426)	(4,029)	(4,171)	(8,613)	(8,439)	(33,130)	(22,628)	(18,368)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	-	0	-	-	(0)	0	(0)	0	(0)	
		Ending Balance	86,972,849	88,006,964	89,040,215	90,071,714	91,089,874	92,123,032	93,156,283	94,185,477	95,215,377	96,221,939	97,240,868	98,265,492	
	Proposed	Beginning Balance	86,708,137	87,763,851	88,819,524	89,874,333	90,927,394	91,967,126	93,021,865	94,076,701	95,127,486	96,178,985	97,207,169	98,247,749	
		Depr Expense	1,057,210	1,057,276	1,057,373	1,057,548	1,058,157	1,058,768	1,059,007	1,059,398	1,059,938	1,061,314	1,063,209	1,064,667	12,713,865
		Cost of Removal	(1,496)	(1,603)	(2,563)	(4,487)	(18,426)	(4,029)	(4,171)	(8,613)	(8,439)	(33,130)	(22,628)	(18,368)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	0	0	-	0	-	-	(0)	0	(0)	0	(0)	
		Ending Balance	87,763,851	88,819,524	89,874,333	90,927,394	91,967,126	93,021,865	94,076,701	95,127,486	96,178,985	97,207,169	98,247,749	99,294,048	
	Change	Beginning Balance	769,445	791,002	812,559	834,119	855,680	877,252	898,833	920,418	942,008	963,608	985,230	1,006,881	
		Depr Expense	21,557	21,558	21,559	21,562	21,571	21,581	21,585	21,591	21,600	21,621	21,652	21,675	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**791,002**	**812,559**	**834,119**	**855,680**	**877,252**	**898,833**	**920,418**	**942,008**	**963,608**	**985,230**	**1,006,881**	**1,028,556**	
Other	**Courtenay Wind Rights**														
		Plant													
		Beginning Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	2,085,661	
		Reserve													
	Original	Remaining Life (Mos)	215	214	213	212	211	210	209	208	207	206	205	204	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	215	214	213	212	211	210	209	208	207	206	205	204	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	593,469	600,410	607,350	614,291	621,231	628,172	635,112	642,052	648,993	655,933	662,874	669,814	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	600,410	607,350	614,291	621,231	628,172	635,112	642,052	648,993	655,933	662,874	669,814	676,754	
	Proposed	Beginning Balance	593,469	600,410	607,350	614,291	621,231	628,172	635,112	642,052	648,993	655,933	662,874	669,814	
		Depr Expense	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	6,940	83,285
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	600,410	607,350	614,291	621,231	628,172	635,112	642,052	648,993	655,933	662,874	669,814	676,754	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Crowned Ridge WF														
		Plant													
		Beginning Balance	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	312,533,834	
		Reserve													
	Original	Remaining Life (Mos)	263	262	261	260	259	258	257	256	255	254	253	252	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	263	262	261	260	259	258	257	256	255	254	253	252	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	41,812,828	42,966,961	44,121,095	45,275,228	46,429,361	47,583,495	48,737,628	49,891,761	51,045,894	52,200,028	53,354,161	54,508,294	
		Depr Expense	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	13,849,600
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	-	0	0	-	(0)	-	-	-	-	-	
		Ending Balance	42,966,961	44,121,095	45,275,228	46,429,361	47,583,495	48,737,628	49,891,761	51,045,894	52,200,028	53,354,161	54,508,294	55,662,428	
	Proposed	Beginning Balance	41,812,828	42,966,961	44,121,095	45,275,228	46,429,361	47,583,495	48,737,628	49,891,761	51,045,894	52,200,028	53,354,161	54,508,294	
		Depr Expense	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	1,154,133	13,849,600
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(0)	-	-	0	0	-	(0)	-	-	-	-	-	
		Ending Balance	42,966,961	44,121,095	45,275,228	46,429,361	47,583,495	48,737,628	49,891,761	51,045,894	52,200,028	53,354,161	54,508,294	55,662,428	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Dakota Range WF														
		Plant													
		Beginning Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	
		Reserve													
	Original	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	276	275	274	273	272	271	270	269	268	267	266	265	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	35,034,381	36,461,343	37,888,305	39,315,267	40,742,229	42,169,191	43,596,153	45,023,115	46,450,077	47,877,038	49,304,000	50,730,962	
		Depr Expense	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	17,123,543
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	36,461,343	37,888,305	39,315,267	40,742,229	42,169,191	43,596,153	45,023,115	46,450,077	47,877,038	49,304,000	50,730,962	52,157,924	
	Proposed	Beginning Balance	35,034,381	36,461,343	37,888,305	39,315,267	40,742,229	42,169,191	43,596,153	45,023,115	46,450,077	47,877,038	49,304,000	50,730,962	
		Depr Expense	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	1,426,962	17,123,543
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	36,461,343	37,888,305	39,315,267	40,742,229	42,169,191	43,596,153	45,023,115	46,450,077	47,877,038	49,304,000	50,730,962	52,157,924	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Foxtail WF														
		Plant													
		Beginning Balance	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	239,158,778	
		Reserve													
	Original	Remaining Life (Mos)	252	251	250	249	248	247	246	245	244	243	242	241	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	252	251	250	249	248	247	246	245	244	243	242	241	
		Net Salvage Rate	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	-9.1%	
	Original	Beginning Balance	42,019,359	42,882,327	43,745,295	44,608,263	45,471,231	46,334,199	47,197,167	48,060,135	48,923,103	49,786,071	50,649,038	51,512,006	
		Depr Expense	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	862,968	10,355,615
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	(0)	0	-	0	-	-	0	-	0	0	
		Ending Balance	42,882,327	43,745,295	44,608,263	45,471,231	46,334,199	47,197,167	48,060,135	48,923,103	49,786,071	50,649,038	51,512,006	52,374,974	
	Proposed	Beginning Balance	42,198,664	43,066,615	43,934,566	44,802,516	45,670,467	46,538,417	47,406,368	48,274,319	49,142,269	50,010,220	50,878,171	51,746,121	
		Depr Expense	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	867,951	10,415,408
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	(0)	0	-	0	-	-	0	-	0	0	
		Ending Balance	43,066,615	43,934,566	44,802,516	45,670,467	46,538,417	47,406,368	48,274,319	49,142,269	50,010,220	50,878,171	51,746,121	52,614,072	
	Change	Beginning Balance	179,305	184,288	189,270	194,253	199,236	204,219	209,201	214,184	219,167	224,149	229,132	234,115	
		Depr Expense	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	4,983	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**184,288**	**189,270**	**194,253**	**199,236**	**204,219**	**209,201**	**214,184**	**219,167**	**224,149**	**229,132**	**234,115**	**239,098**	
Other	Foxtail Wind Rights														
		Plant													
		Beginning Balance	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	177,364	
		Reserve													
	Original	Remaining Life (Mos)	252	251	250	249	248	247	246	245	244	243	242	241	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	252	251	250	249	248	247	246	245	244	243	242	241	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	27,226	27,821	28,417	29,013	29,609	30,204	30,800	31,396	31,992	32,588	33,183	33,779	
		Depr Expense	596	596	596	596	596	596	596	596	596	596	596	596	7,149
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	27,821	28,417	29,013	29,609	30,204	30,800	31,396	31,992	32,588	33,183	33,779	34,375	
	Proposed	Beginning Balance	27,226	27,821	28,417	29,013	29,609	30,204	30,800	31,396	31,992	32,588	33,183	33,779	
		Depr Expense	596	596	596	596	596	596	596	596	596	596	596	596	7,149
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	27,821	28,417	29,013	29,609	30,204	30,800	31,396	31,992	32,588	33,183	33,779	34,375	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Freeborn WF														
		Plant													
		Beginning Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	
		Reserve													
	Original	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	269	268	267	266	265	264	263	262	261	260	259	258	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	37,796,036	38,999,962	40,203,887	41,407,813	42,611,738	43,815,663	45,019,589	46,223,514	47,427,440	48,631,365	49,835,290	51,039,216	
		Depr Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,105
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	(0)	0	-	-	-	-	-	-	-	-	
		Ending Balance	38,999,962	40,203,887	41,407,813	42,611,738	43,815,663	45,019,589	46,223,514	47,427,440	48,631,365	49,835,290	51,039,216	52,243,141	
	Proposed	Beginning Balance	37,796,036	38,999,962	40,203,887	41,407,813	42,611,738	43,815,663	45,019,589	46,223,514	47,427,440	48,631,365	49,835,290	51,039,216	
		Depr Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,105
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	(0)	0	-	-	-	-	-	-	-	-	
		Ending Balance	38,999,962	40,203,887	41,407,813	42,611,738	43,815,663	45,019,589	46,223,514	47,427,440	48,631,365	49,835,290	51,039,216	52,243,141	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Fuel Holders (Wind-to-Battery)														
		Plant													
		Beginning Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	4,128,902	
		Reserve													
	Original	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	-	-	-	-	-	-	-	-	-	-	-	-	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	4,128,902	4,128,902	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	(5,608,484)	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,128,902	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	
	Proposed	Beginning Balance	4,128,902	4,128,902	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	(5,608,484)	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	4,128,902	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	(1,479,582)	
	Change	Beginning Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Grand Meadow WF														
		Plant													
		Beginning Balance	127,245,806	127,900,891	128,449,871	129,031,996	129,062,042	129,120,389	129,148,096	129,175,453	129,209,498	129,242,198	129,308,100	129,355,752	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	655,085	548,979	582,125	30,046	58,347	27,707	27,357	34,045	32,700	65,903	47,652	38,737	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	127,900,891	128,449,871	129,031,996	129,062,042	129,120,389	129,148,096	129,175,453	129,209,498	129,242,198	129,308,100	129,355,752	129,394,489	
		Reserve													
	Original	Remaining Life (Mos)	119	118	117	116	115	114	113	112	111	110	109	108	
		Net Salvage Rate	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	-11.1%	
	Proposed	Remaining Life (Mos)	119	118	117	116	115	114	113	112	111	110	109	108	
		Net Salvage Rate	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	-12.5%	
	Original	Beginning Balance	(57,777,853)	(56,101,771)	(54,420,007)	(52,733,093)	(51,043,676)	(49,357,008)	(47,666,424)	(45,975,518)	(44,285,039)	(42,594,056)	(40,906,215)	(39,215,725)	
		Depr Expense	1,676,572	1,682,245	1,687,620	1,690,560	1,691,010	1,691,453	1,691,731	1,692,046	1,692,393	1,692,921	1,693,537	1,694,005	20,276,091
		Cost of Removal	(491)	(481)	(707)	(1,143)	(4,343)	(869)	(825)	(1,568)	(1,411)	(5,080)	(3,048)	(2,057)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	1	1	1	1	1	1	1	1	
		Ending Balance	(56,101,771)	(54,420,007)	(52,733,093)	(51,043,676)	(49,357,008)	(47,666,424)	(45,975,518)	(44,285,039)	(42,594,056)	(40,906,215)	(39,215,725)	(37,523,777)	
	Proposed	Beginning Balance	(57,120,781)	(55,435,213)	(53,743,890)	(52,047,350)	(50,348,270)	(48,651,934)	(46,951,676)	(45,251,093)	(43,550,933)	(41,850,265)	(40,152,732)	(38,452,543)	
		Depr Expense	1,686,059	1,691,803	1,697,246	1,700,223	1,700,679	1,701,126	1,701,408	1,701,727	1,702,079	1,702,612	1,703,236	1,703,709	20,391,906
		Cost of Removal	(491)	(481)	(707)	(1,143)	(4,343)	(869)	(825)	(1,568)	(1,411)	(5,080)	(3,048)	(2,057)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	1	1	1	1	1	1	1	1	
		Ending Balance	(55,435,213)	(53,743,890)	(52,047,350)	(50,348,270)	(48,651,934)	(46,951,676)	(45,251,093)	(43,550,933)	(41,850,265)	(40,152,732)	(38,452,543)	(36,750,891)	
	Change	Beginning Balance	657,071	666,558	676,117	685,743	695,406	705,074	714,748	724,425	734,106	743,791	753,483	763,182	
		Depr Expense	9,487	9,558	9,626	9,663	9,668	9,674	9,677	9,681	9,685	9,691	9,699	9,704	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**666,558**	**676,117**	**685,743**	**695,406**	**705,074**	**714,748**	**724,425**	**734,106**	**743,791**	**753,483**	**763,182**	**772,886**	
Other	Grand Meadow Wind Rights														
		Plant													
		Beginning Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	10,672,452	
		Reserve													
	Original	Remaining Life (Mos)	119	118	117	116	115	114	113	112	111	110	109	108	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	119	118	117	116	115	114	113	112	111	110	109	108	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	5,927,283	5,967,158	6,007,033	6,046,909	6,086,784	6,126,659	6,166,535	6,206,410	6,246,286	6,286,161	6,326,036	6,365,912	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	0	-	-	-	-	0	(0)	0	(0)	-	
		Ending Balance	5,967,158	6,007,033	6,046,909	6,086,784	6,126,659	6,166,535	6,206,410	6,246,286	6,286,161	6,326,036	6,365,912	6,405,787	
	Proposed	Beginning Balance	5,927,283	5,967,158	6,007,033	6,046,909	6,086,784	6,126,659	6,166,535	6,206,410	6,246,286	6,286,161	6,326,036	6,365,912	
		Depr Expense	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	39,875	478,504
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	0	-	-	-	-	0	(0)	0	(0)	-	
		Ending Balance	5,967,158	6,007,033	6,046,909	6,086,784	6,126,659	6,166,535	6,206,410	6,246,286	6,286,161	6,326,036	6,365,912	6,405,787	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	High Bridge														
		Plant													
		Beginning Balance	432,977,985	432,982,688	432,988,298	435,926,073	436,364,192	436,535,399	436,572,411	442,960,731	443,677,099	444,599,115	445,203,017	445,631,314	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	4,703	5,609	2,937,775	438,119	171,207	37,012	6,388,321	716,367	922,017	603,902	428,297	361,768	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	432,982,688	432,988,298	435,926,073	436,364,192	436,535,399	436,572,411	442,960,731	443,677,099	444,599,115	445,203,017	445,631,314	445,993,081	
		Reserve													
	Original	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	
	Proposed	Remaining Life (Mos)	293	292	291	290	289	288	287	286	285	284	283	282	
		Net Salvage Rate	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	-4.3%	
	Original	Beginning Balance	139,232,605	140,286,877	141,341,167	142,400,691	143,466,238	144,532,867	145,280,033	146,359,747	147,452,314	148,248,382	149,347,749	150,449,009	
		Depr Expense	1,054,273	1,054,291	1,059,526	1,065,550	1,066,641	1,067,572	1,079,716	1,092,571	1,096,072	1,099,381	1,101,269	1,102,719	12,939,581
		Cost of Removal	(1)	(1)	(2)	(3)	(12)	(320,405)	(2)	(4)	(300,004)	(14)	(8)	(6)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	(0)	0	0	(0)	0	0	0	
		Ending Balance	140,286,877	141,341,167	142,400,691	143,466,238	144,532,867	145,280,033	146,359,747	147,452,314	148,248,382	149,347,749	150,449,009	151,551,722	
	Proposed	Beginning Balance	139,596,361	140,661,214	141,726,085	142,796,230	143,872,444	144,949,750	145,707,595	146,798,077	147,901,512	148,708,471	149,818,750	150,930,938	
		Depr Expense	1,064,854	1,064,872	1,070,147	1,076,218	1,077,317	1,078,251	1,090,484	1,103,439	1,106,963	1,110,293	1,112,196	1,113,657	13,068,691
		Cost of Removal	(1)	(1)	(2)	(3)	(12)	(320,405)	(2)	(4)	(300,004)	(14)	(8)	(6)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	0	0	0	0	(0)	0	0	(0)	0	0	0	
		Ending Balance	140,661,214	141,726,085	142,796,230	143,872,444	144,949,750	145,707,595	146,798,077	147,901,512	148,708,471	149,818,750	150,930,938	152,044,589	
	Change	Beginning Balance	363,757	374,337	384,918	395,539	406,207	416,883	427,562	438,330	449,198	460,089	471,001	481,928	
		Depr Expense	10,581	10,581	10,621	10,668	10,676	10,679	10,769	10,868	10,891	10,912	10,927	10,938	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**374,337**	**384,918**	**395,539**	**406,207**	**416,883**	**427,562**	**438,330**	**449,198**	**460,089**	**471,001**	**481,928**	**492,867**	
Other	Inver Hills														
		Plant													
		Beginning Balance	64,607,515	64,607,717	64,608,078	64,608,986	64,611,330	64,624,620	64,628,594	64,633,935	64,647,932	64,665,585	64,749,360	64,816,325	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	201	361	908	2,344	13,290	3,974	5,341	13,997	17,652	83,775	66,965	57,099	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	64,607,717	64,608,078	64,608,986	64,611,330	64,624,620	64,628,594	64,633,935	64,647,932	64,665,585	64,749,360	64,816,325	64,873,424	
		Reserve													
	Original	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	-18.3%	
	Proposed	Remaining Life (Mos)	36	35	34	33	32	31	30	29	28	27	26	25	
		Net Salvage Rate	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	-19.4%	
	Original	Beginning Balance	64,563,512	64,893,157	65,222,811	65,552,486	65,882,220	66,212,242	66,542,595	66,873,131	67,204,062	67,535,662	67,869,482	68,206,732	
		Depr Expense	329,647	329,657	329,679	329,737	330,026	330,356	330,540	330,934	331,603	333,825	337,255	340,190	3,983,450
		Cost of Removal	(0)	(0)	(0)	(1)	(3)	(1)	(0)	(1)	(1)	(3)	(2)	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	
		Ending Balance	64,893,157	65,222,811	65,552,486	65,882,220	66,212,242	66,542,595	66,873,131	67,204,062	67,535,662	67,869,482	68,206,732	68,546,919	
	Proposed	Beginning Balance	64,902,932	65,242,889	65,582,856	65,922,845	66,262,893	66,603,230	66,943,903	67,284,761	67,626,017	67,967,947	68,312,119	68,659,753	
		Depr Expense	339,960	339,970	339,992	340,051	340,343	340,675	340,861	341,259	341,934	344,177	347,638	350,601	4,107,462
		Cost of Removal	(0)	(0)	(0)	(1)	(3)	(1)	(0)	(1)	(1)	(3)	(2)	(1)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	
		Ending Balance	65,242,889	65,582,856	65,922,845	66,262,893	66,603,230	66,943,903	67,284,761	67,626,017	67,967,947	68,312,119	68,659,753	69,010,350	
	Change	Beginning Balance	339,420	349,732	360,045	370,359	380,672	390,989	401,308	411,629	421,954	432,285	442,637	453,021	
		Depr Expense	10,313	10,313	10,313	10,314	10,316	10,319	10,321	10,325	10,331	10,352	10,384	10,411	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**349,732**	**360,045**	**370,359**	**380,672**	**390,989**	**401,308**	**411,629**	**421,954**	**432,285**	**442,637**	**453,021**	**463,432**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	Jeffers WF														
		Plant													
		Beginning Balance	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	69,978,427	
		Reserve													
	Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
	Original	Beginning Balance	10,595,037	10,847,806	11,100,576	11,353,345	11,606,114	11,858,884	12,111,653	12,364,423	12,617,192	12,869,961	13,122,731	13,375,500	
		Depr Expense	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	3,033,233
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	10,847,806	11,100,576	11,353,345	11,606,114	11,858,884	12,111,653	12,364,423	12,617,192	12,869,961	13,122,731	13,375,500	13,628,270	
	Proposed	Beginning Balance	10,595,037	10,847,806	11,100,576	11,353,345	11,606,114	11,858,884	12,111,653	12,364,423	12,617,192	12,869,961	13,122,731	13,375,500	
		Depr Expense	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	252,769	3,033,233
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	10,847,806	11,100,576	11,353,345	11,606,114	11,858,884	12,111,653	12,364,423	12,617,192	12,869,961	13,122,731	13,375,500	13,628,270	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
Other	Jeffers Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	177	177	176	175	175	174	173	173	172	171	171	170	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	177	176	175	175	174	173	173	172	171	171	170	169	
	Proposed	Beginning Balance	177	177	176	175	175	174	173	173	172	171	171	170	
		Depr Expense	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(8)
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	177	176	175	175	174	173	173	172	171	171	170	169	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

Functional Class	Plant Name		2024 January	February	March	April	May	June	July	August	September	October	November	December	
Other	Lake Benton WF														
		Plant													
		Beginning Balance	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	161,290,643	
		Reserve													
	Original	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	-10.8%	
	Original	Beginning Balance	28,616,036	29,199,241	29,782,445	30,365,650	30,948,854	31,532,058	32,115,263	32,698,467	33,281,672	33,864,876	34,448,081	35,031,285	
		Depr Expense	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	583,204	6,998,453
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	0	-	-	-	(0)	0	-	-	-	
		Ending Balance	29,199,241	29,782,445	30,365,650	30,948,854	31,532,058	32,115,263	32,698,467	33,281,672	33,864,876	34,448,081	35,031,285	35,614,489	
	Proposed	Beginning Balance	29,080,417	29,676,551	30,272,684	30,868,818	31,464,952	32,061,086	32,657,220	33,253,354	33,849,488	34,445,622	35,041,756	35,637,890	
		Depr Expense	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	596,134	7,153,607
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	0	(0)	0	-	-	-	(0)	0	-	-	-	
		Ending Balance	29,676,551	30,272,684	30,868,818	31,464,952	32,061,086	32,657,220	33,253,354	33,849,488	34,445,622	35,041,756	35,637,890	36,234,024	
	Change	Beginning Balance	464,380	477,310	490,239	503,169	516,098	529,028	541,957	554,887	567,816	580,746	593,675	606,605	
		Depr Expense	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	12,930	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**477,310**	**490,239**	**503,169**	**516,098**	**529,028**	**541,957**	**554,887**	**567,816**	**580,746**	**593,675**	**606,605**	**619,534**	
Other	Lake Benton Wind Rights														
		Plant													
		Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Reserve													
	Original	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	251	250	249	248	247	246	245	244	243	242	241	240	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Proposed	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	

				2024												
Functional Class	Plant Name			January	February	March	April	May	June	July	August	September	October	November	December	
Other	Mower WF															
			Plant													
			Beginning Balance	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Additions	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
			Ending Balance	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	223,361,602	
			Reserve													
		Original	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
			Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
		Proposed	Remaining Life (Mos)	264	263	262	261	260	259	258	257	256	255	254	253	
			Net Salvage Rate	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	-10.5%	
		Original	Beginning Balance	85,876,494	86,486,108	87,095,722	87,705,336	88,314,950	88,924,563	89,534,177	90,143,791	90,753,405	91,363,019	91,972,633	92,582,247	
			Depr Expense	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	7,315,367
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	
			Ending Balance	86,486,108	87,095,722	87,705,336	88,314,950	88,924,563	89,534,177	90,143,791	90,753,405	91,363,019	91,972,633	92,582,247	93,191,861	
		Proposed	Beginning Balance	85,876,494	86,486,108	87,095,722	87,705,336	88,314,950	88,924,563	89,534,177	90,143,791	90,753,405	91,363,019	91,972,633	92,582,247	
			Depr Expense	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	609,614	7,315,367
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	
			Ending Balance	86,486,108	87,095,722	87,705,336	88,314,950	88,924,563	89,534,177	90,143,791	90,753,405	91,363,019	91,972,633	92,582,247	93,191,861	
		Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
			Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
			Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	
Other	Mower Wind Rights															
			Plant													
			Beginning Balance	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Additions	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
			Ending Balance	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	626,931	
			Reserve													
		Original	Remaining Life (Mos)	267	266	265	264	263	262	261	260	259	258	257	256	
			Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
		Proposed	Remaining Life (Mos)	267	266	265	264	263	262	261	260	259	258	257	256	
			Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
		Original	Beginning Balance	69,887	71,973	74,060	76,146	78,232	80,319	82,405	84,491	86,578	88,664	90,750	92,836	
			Depr Expense	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	25,036
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	(0)	-	-	-	-	-	-	0	(0)	-	-	-	
			Ending Balance	71,973	74,060	76,146	78,232	80,319	82,405	84,491	86,578	88,664	90,750	92,836	94,923	
		Proposed	Beginning Balance	69,887	71,973	74,060	76,146	78,232	80,319	82,405	84,491	86,578	88,664	90,750	92,836	
			Depr Expense	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	2,086	25,036
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	(0)	-	-	-	-	-	-	0	(0)	-	-	-	
			Ending Balance	71,973	74,060	76,146	78,232	80,319	82,405	84,491	86,578	88,664	90,750	92,836	94,923	
		Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
			Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
			Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
			Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
			Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
			Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
			Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2024												
Functional Class	Plant Name		January	February	March	April	May	June	July	August	September	October	November	December	
Other	Nobles WF														
		Plant													
		Beginning Balance	288,053,400	288,073,599	288,093,794	288,114,083	288,134,552	288,163,107	288,186,518	288,211,465	288,244,294	288,279,277	288,346,959	288,401,257	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	20,198	20,195	20,289	20,469	28,555	23,411	24,948	32,828	34,983	67,682	54,298	52,010	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	288,073,599	288,093,794	288,114,083	288,134,552	288,163,107	288,186,518	288,211,465	288,244,294	288,279,277	288,346,959	288,401,257	288,453,267	
		Reserve													
	Original	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	
	Proposed	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Original	Beginning Balance	(163,550,880)	(160,271,896)	(156,992,762)	(153,713,486)	(150,434,077)	(147,155,388)	(143,875,908)	(140,596,406)	(137,317,541)	(148,422,837)	(145,041,937)	(141,659,023)	
		Depr Expense	3,279,008	3,279,159	3,279,312	3,279,466	3,279,657	3,279,861	3,280,052	3,280,284	3,334,035	3,388,347	3,388,883	3,389,354	39,737,420
		Cost of Removal	(25)	(24)	(35)	(57)	(967)	(381)	(549)	(1,419)	(14,439,334)	(7,447)	(5,968)	(5,716)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	3	(1)	(1)	(1)	
		Ending Balance	(160,271,896)	(156,992,762)	(153,713,486)	(150,434,077)	(147,155,388)	(143,875,908)	(140,596,406)	(137,317,541)	(148,422,837)	(145,041,937)	(141,659,023)	(138,275,385)	
	Proposed	Beginning Balance	(161,382,399)	(158,068,220)	(154,753,885)	(151,439,405)	(148,124,789)	(144,810,888)	(141,496,192)	(138,181,469)	(134,867,378)	(145,937,441)	(142,521,300)	(139,103,132)	
		Depr Expense	3,314,205	3,314,359	3,314,515	3,314,674	3,314,869	3,315,078	3,315,273	3,315,511	3,369,267	3,423,589	3,424,137	3,424,618	40,160,094
		Cost of Removal	(25)	(24)	(35)	(57)	(967)	(381)	(549)	(1,419)	(14,439,334)	(7,447)	(5,968)	(5,716)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	3	(1)	(1)	(1)	
		Ending Balance	(158,068,220)	(154,753,885)	(151,439,405)	(148,124,789)	(144,810,888)	(141,496,192)	(138,181,469)	(134,867,378)	(145,937,441)	(142,521,300)	(139,103,132)	(135,684,230)	
	Change	Beginning Balance	2,168,480	2,203,677	2,238,877	2,274,081	2,309,288	2,344,500	2,379,716	2,414,937	2,450,163	2,485,396	2,520,638	2,555,891	
		Depr Expense	35,197	35,200	35,204	35,207	35,212	35,216	35,221	35,226	35,232	35,242	35,253	35,264	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**2,203,677**	**2,238,877**	**2,274,081**	**2,309,288**	**2,344,500**	**2,379,716**	**2,414,937**	**2,450,163**	**2,485,396**	**2,520,638**	**2,555,891**	**2,591,155**	
Other	Nobles Wind Rights														
		Plant													
		Beginning Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	3,884,834	
		Reserve													
	Original	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Proposed	Remaining Life (Mos)	143	142	141	140	139	138	137	136	135	134	133	132	
		Net Salvage Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Original	Beginning Balance	2,019,938	2,032,980	2,046,021	2,059,062	2,072,103	2,085,145	2,098,186	2,111,227	2,124,268	2,137,309	2,150,351	2,163,392	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	-	-	0	(0)	-	-	-	(0)	0	
		Ending Balance	2,032,980	2,046,021	2,059,062	2,072,103	2,085,145	2,098,186	2,111,227	2,124,268	2,137,309	2,150,351	2,163,392	2,176,433	
	Proposed	Beginning Balance	2,019,938	2,032,980	2,046,021	2,059,062	2,072,103	2,085,145	2,098,186	2,111,227	2,124,268	2,137,309	2,150,351	2,163,392	
		Depr Expense	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	13,041	156,495
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	0	(0)	-	-	-	0	(0)	-	-	-	(0)	0	
		Ending Balance	2,032,980	2,046,021	2,059,062	2,072,103	2,085,145	2,098,186	2,111,227	2,124,268	2,137,309	2,150,351	2,163,392	2,176,433	
	Change	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	
		Depr Expense	-	-	-	-	-	-	-	-	-	-	-	-	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	

			2024												
Functional Class	**Plant Name**		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	
Other	**Pleasant Valley WF**														
		Plant													
		Beginning Balance	336,113,394	336,122,194	336,132,928	336,151,886	336,187,853	336,345,813	336,382,728	336,423,136	336,510,613	336,600,052	336,964,650	337,225,614	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	8,800	10,734	18,958	35,967	157,960	36,915	40,408	87,477	89,439	364,598	260,964	223,328	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	336,122,194	336,132,928	336,151,886	336,187,853	336,345,813	336,382,728	336,423,136	336,510,613	336,600,052	336,964,650	337,225,614	337,448,942	
		Reserve													
	Original	Remaining Life (Mos)	204	203	202	201	200	199	198	197	196	195	194	193	
		Net Salvage Rate	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	-8.5%	
	Proposed	Remaining Life (Mos)	204	203	202	201	200	199	198	197	196	195	194	193	
		Net Salvage Rate	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	-11.7%	
	Original	Beginning Balance	116,049,450	117,267,512	118,485,507	119,702,970	120,919,325	122,127,130	123,344,660	124,562,208	125,776,810	126,991,872	128,189,120	129,395,666	
		Depr Expense	1,218,817	1,218,874	1,218,959	1,219,118	1,219,681	1,220,249	1,220,475	1,220,850	1,221,372	1,222,716	1,224,578	1,226,025	14,651,714
		Cost of Removal	(755)	(878)	(1,497)	(2,763)	(11,875)	(2,719)	(2,927)	(6,248)	(6,311)	(25,468)	(18,031)	(15,265)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	-	0	-	-	(0)	-	-	-	-	
		Ending Balance	117,267,512	118,485,507	119,702,970	120,919,325	122,127,130	123,344,660	124,562,208	125,776,810	126,991,872	128,189,120	129,395,666	130,606,427	
	Proposed	Beginning Balance	117,651,797	118,914,729	120,177,596	121,439,932	122,701,165	123,953,864	125,216,303	126,478,766	127,738,294	128,998,296	130,240,521	131,492,097	
		Depr Expense	1,263,687	1,263,745	1,263,833	1,263,996	1,264,574	1,265,158	1,265,390	1,265,776	1,266,312	1,267,694	1,269,607	1,271,095	15,190,866
		Cost of Removal	(755)	(878)	(1,497)	(2,763)	(11,875)	(2,719)	(2,927)	(6,248)	(6,311)	(25,468)	(18,031)	(15,265)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	(0)	-	-	0	-	-	(0)	-	-	-	-	
		Ending Balance	118,914,729	120,177,596	121,439,932	122,701,165	123,953,864	125,216,303	126,478,766	127,738,294	128,998,296	130,240,521	131,492,097	132,747,927	
	Change	Beginning Balance	1,602,347	1,647,217	1,692,088	1,736,962	1,781,840	1,826,733	1,871,643	1,916,558	1,961,484	2,006,424	2,051,401	2,096,431	
		Depr Expense	44,870	44,871	44,874	44,878	44,894	44,909	44,915	44,926	44,940	44,977	45,029	45,069	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**1,647,217**	**1,692,088**	**1,736,962**	**1,781,840**	**1,826,733**	**1,871,643**	**1,916,558**	**1,961,484**	**2,006,424**	**2,051,401**	**2,096,431**	**2,141,500**	
Other	**Riverside**														
		Plant													
		Beginning Balance	349,380,161	349,391,196	349,398,041	349,410,401	349,435,692	349,558,288	349,590,746	349,631,016	349,730,695	349,850,802	350,782,003	356,259,305	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Additions	11,035	6,845	12,360	25,291	122,597	32,458	40,270	99,679	120,107	931,200	5,477,302	806,317	
		Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	349,391,196	349,398,041	349,410,401	349,435,692	349,558,288	349,590,746	349,631,016	349,730,695	349,850,802	350,782,003	356,259,305	357,065,622	
		Reserve													
	Original	Remaining Life (Mos)	303	302	301	300	299	298	297	296	295	294	293	292	
		Net Salvage Rate	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	-11.3%	
	Proposed	Remaining Life (Mos)	303	302	301	300	299	298	297	296	295	294	293	292	
		Net Salvage Rate	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	-13.2%	
	Original	Beginning Balance	129,963,068	130,792,564	131,647,135	132,501,736	133,356,399	134,211,269	135,066,502	135,921,873	136,777,491	137,633,527	138,491,477	139,361,641	
		Depr Expense	854,507	854,582	854,617	854,687	854,963	855,252	855,389	855,652	856,067	858,057	870,229	882,598	10,306,599
		Cost of Removal	(25,010)	(10)	(15)	(24)	(91)	(18)	(17)	(33)	(30)	(107)	(64)	(230,043)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	130,792,564	131,647,135	132,501,736	133,356,399	134,211,269	135,066,502	135,921,873	136,777,491	137,633,527	138,491,477	139,361,641	140,014,195	
	Proposed	Beginning Balance	130,648,934	131,498,075	132,372,291	133,246,539	134,120,849	134,995,372	135,870,262	136,745,292	137,620,574	138,496,281	139,373,935	140,264,012	
		Depr Expense	874,152	874,227	874,263	874,335	874,615	874,909	875,048	875,316	875,738	877,762	890,142	902,715	10,543,222
		Cost of Removal	(25,010)	(10)	(15)	(24)	(91)	(18)	(17)	(33)	(30)	(107)	(64)	(230,043)	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
		Ending Balance	131,498,075	132,372,291	133,246,539	134,120,849	134,995,372	135,870,262	136,745,292	137,620,574	138,496,281	139,373,935	140,264,012	140,936,684	
	Change	Beginning Balance	685,866	705,511	725,157	744,803	764,450	784,103	803,760	823,419	843,083	862,754	882,459	902,372	
		Depr Expense	19,645	19,646	19,646	19,647	19,652	19,657	19,659	19,664	19,671	19,705	19,913	20,117	
		Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	
		Salvage	-	-	-	-	-	-	-	-	-	-	-	-	
		Retirements	-	-	-	-	-	-	-	-	-	-	-	-	
		Transfers/Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	
		Ending Balance	**705,511**	**725,157**	**744,803**	**764,450**	**784,103**	**803,760**	**823,419**	**843,083**	**862,754**	**882,459**	**902,372**	**922,489**	

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 1 of 8

		2021												
Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Blazing Star II Wind	Plant Beginning Balance	-	327,585,821	334,753,567	335,365,491	334,683,517	335,230,471	358,628,261	336,462,858	337,402,571	337,859,314	338,590,480	338,605,000	-
	Plant Additions	327,585,821	7,167,746	611,924	(681,975)	546,955	23,397,790	(22,165,403)	939,713	456,743	731,166	14,520	140,018	338,745,018
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	327,585,821	334,753,567	335,365,491	334,683,517	335,230,471	358,628,261	336,462,858	337,402,571	337,859,314	338,590,480	338,605,000	338,745,018	338,745,018
	Reserve Beginning Balance	-	601,300	1,819,104	3,051,283	4,283,333	5,515,131	6,791,624	8,070,425	9,309,337	10,550,883	11,794,676	13,039,885	-
	Depreciation Expense	601,300	1,217,804	1,232,180	1,232,050	1,231,798	1,276,493	1,278,801	1,238,912	1,241,546	1,243,793	1,245,209	1,245,547	14,285,431
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	1	1
	Salvage	-	-	-	-	-	-	-	-	-	-	-	(24,991)	(24,991)
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	601,300	1,819,104	3,051,283	4,283,333	5,515,131	6,791,624	8,070,425	9,309,337	10,550,883	11,794,676	13,039,885	14,260,441	14,260,441
Dakota Range Wind	Plant Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	394,985,740	394,985,740
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	-	-	-	-	-	-	-	394,985,740	394,985,740
	Reserve Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	727,432	727,432
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	-	-	-	-	-	-	-	727,432	727,432
Freeborn Wind	Plant Beginning Balance	-	-	-	-	-	320,253,486	318,807,725	318,745,384	324,429,134	325,243,100	326,680,487	326,968,630	-
	Plant Additions	-	-	-	-	320,253,486	(1,445,761)	(62,341)	5,683,750	813,966	1,437,387	288,143	318,218	327,286,848
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	320,253,486	318,807,725	318,745,384	324,429,134	325,243,100	326,680,487	326,968,630	327,286,848	327,286,848
	Reserve Beginning Balance	-	-	-	-	-	587,841	1,762,819	2,935,011	4,117,624	5,312,326	6,511,229	7,713,365	-
	Depreciation Expense	-	-	-	-	587,841	1,174,978	1,172,192	1,182,614	1,194,701	1,198,904	1,202,135	1,203,300	8,916,664
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	(14,811)	(14,811)
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	587,841	1,762,819	2,935,011	4,117,624	5,312,326	6,511,229	7,713,365	8,901,853	8,901,853

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 2 of 8

		2021												
Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Mower Wind	Plant Beginning Balance	-	-	-	223,243,490	223,433,121	223,261,239	223,377,502	223,745,342	223,844,268	223,988,533	223,988,533	223,988,533	-
	Plant Additions	-	-	223,243,490	189,631	(171,882)	116,263	367,840	98,926	144,265	-	-	-	223,988,533
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	223,243,490	223,433,121	223,261,239	223,377,502	223,745,342	223,844,268	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Reserve Beginning Balance	-	-	-	65,792,277	66,390,153	66,988,063	67,585,869	68,184,576	68,784,154	69,384,187	69,984,492	70,584,796	-
	Depreciation Expense	-	-	323,276	597,877	597,909	597,806	598,707	599,578	600,033	600,305	600,305	600,309	5,716,105
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(2,564)	(2,564)
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	65,469,001	-	-	-	-	-	-	-	-	-	65,469,001
	Reserve Ending Balance	-	-	65,792,277	66,390,153	66,988,063	67,585,869	68,184,576	68,784,154	69,384,187	69,984,492	70,584,796	71,182,541	71,182,541
Northern Wind	Plant Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco Solar	Plant Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-

All wind projects will have a 25 year initial life and a negative 10.5% net salvage
Sherco solar will have a proposed 35 year life and zero percent net salvage

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 3 of 8

		2022												
Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Blazing Star II Wind	Plant Beginning Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018
	Reserve Beginning Balance	14,260,441	15,506,298	16,752,156	17,998,013	19,243,871	20,489,728	21,735,586	22,981,443	24,227,300	25,473,158	26,719,015	27,964,873	14,260,441
	Depreciation Expense	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	14,950,289
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	15,506,298	16,752,156	17,998,013	19,243,871	20,489,728	21,735,586	22,981,443	24,227,300	25,473,158	26,719,015	27,964,873	29,210,730	29,210,730
Dakota Range Wind	Plant Beginning Balance	394,985,740	395,106,865	395,220,544	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	394,985,740
	Plant Additions	121,126	113,678	(7,097,583)	-	-	-	-	-	-	-	-	-	(6,862,779)
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	395,106,865	395,220,544	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960
	Reserve Beginning Balance	727,432	2,182,519	3,638,039	5,077,931	6,507,517	7,937,104	9,366,690	10,796,276	12,225,862	13,655,449	15,085,035	16,514,621	727,432
	Depreciation Expense	1,455,087	1,455,520	1,442,658	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	17,219,541
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	(26)	-	-	-	-	-	-	-	-	-	(26)
	Salvage	-	-	(2,739)	-	-	-	-	-	-	-	-	-	(2,739)
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	2,182,519	3,638,039	5,077,931	6,507,517	7,937,104	9,366,690	10,796,276	12,225,862	13,655,449	15,085,035	16,514,621	17,944,207	17,944,207
Freeborn Wind	Plant Beginning Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848
	Reserve Beginning Balance	8,901,853	10,105,778	11,309,704	12,513,629	13,717,554	14,921,480	16,125,405	17,329,330	18,533,256	19,737,181	20,941,106	22,145,031	8,901,853
	Depreciation Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,104
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	10,105,778	11,309,704	12,513,629	13,717,554	14,921,480	16,125,405	17,329,330	18,533,256	19,737,181	20,941,106	22,145,031	23,348,956	23,348,956

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 4 of 8

2022

Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Mower Wind	Plant Beginning Balance	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Reserve Beginning Balance	71,182,541	71,782,854	72,383,168	72,983,481	73,583,794	74,184,108	74,784,421	75,384,735	75,985,048	76,585,361	77,185,675	77,785,988	71,182,541
	Depreciation Expense	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	7,203,760
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	71,782,854	72,383,168	72,983,481	73,583,794	74,184,108	74,784,421	75,384,735	75,985,048	76,585,361	77,185,675	77,785,988	78,386,301	78,386,301
Northern Wind	Plant Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	223,569,537	223,569,537
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	-	-	-	-	-	-	-	223,569,537	223,569,537
	Reserve Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	372,616	372,616
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	-	-	-	-	-	-	-	372,616	372,616
Sherco Solar	Plant Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-

All wind projects will have a 25 year initial life and a negat
Sherco solar will have a proposed 35 year life and zero pe

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 5 of 8

		2023												
Plant	Category	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**YTD Summary**
Blazing Star II Wind	Plant Beginning Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018
	Reserve Beginning Balance	29,210,730	30,456,588	31,702,445	32,948,303	34,194,160	35,440,017	36,685,875	37,931,732	39,177,590	40,423,447	41,669,305	42,915,162	29,210,730
	Depreciation Expense	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	14,950,289
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	30,456,588	31,702,445	32,948,303	34,194,160	35,440,017	36,685,875	37,931,732	39,177,590	40,423,447	41,669,305	42,915,162	44,161,020	44,161,020
Dakota Range Wind	Plant Beginning Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960
	Reserve Beginning Balance	17,944,207	19,373,794	20,803,380	22,232,966	23,662,552	25,092,139	26,521,725	27,951,311	29,380,897	30,810,483	32,240,070	33,669,656	17,944,207
	Depreciation Expense	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	17,155,035
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	19,373,794	20,803,380	22,232,966	23,662,552	25,092,139	26,521,725	27,951,311	29,380,897	30,810,483	32,240,070	33,669,656	35,099,242	35,099,242
Freeborn Wind	Plant Beginning Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848
	Reserve Beginning Balance	23,348,956	24,552,881	25,756,807	26,960,732	28,164,657	29,368,583	30,572,508	31,776,433	32,980,359	34,184,284	35,388,209	36,592,134	23,348,956
	Depreciation Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,104
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	24,552,881	25,756,807	26,960,732	28,164,657	29,368,583	30,572,508	31,776,433	32,980,359	34,184,284	35,388,209	36,592,134	37,796,060	37,796,060

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 6 of 8

		2023												
Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Mower Wind	Plant Beginning Balance	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Reserve Beginning Balance	78,386,301	78,986,615	79,586,928	80,187,241	80,787,555	81,387,868	81,988,181	82,588,495	83,188,808	83,789,121	84,389,435	84,989,748	78,386,301
	Depreciation Expense	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	7,203,760
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	78,986,615	79,586,928	80,187,241	80,787,555	81,387,868	81,988,181	82,588,495	83,188,808	83,789,121	84,389,435	84,989,748	85,590,061	85,590,061
Northern Wind	Plant Beginning Balance	223,569,537	223,683,347	223,793,785	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	223,569,537
	Plant Additions	113,809	110,439	1,201,730	-	-	-	-	-	-	-	-	-	1,425,978
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	223,683,347	223,793,785	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516
	Reserve Beginning Balance	372,616	1,118,037	1,863,833	2,611,815	3,361,800	4,111,785	4,861,770	5,611,755	6,361,740	7,111,725	7,861,710	8,611,695	372,616
	Depreciation Expense	745,421	745,795	747,982	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	8,989,064
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	1,118,037	1,863,833	2,611,815	3,361,800	4,111,785	4,861,770	5,611,755	6,361,740	7,111,725	7,861,710	8,611,695	9,361,680	9,361,680
Sherco Solar	Plant Beginning Balance	-	-	-	-	-	-	-	-	-	-	273,625,359	284,397,683	-
	Plant Additions	-	-	-	-	-	-	-	-	-	273,625,359	10,772,325	19,597,187	303,994,870
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	-	-	-	-	-	-	-	-	-	273,625,359	284,397,683	303,994,870	303,994,870
	Reserve Beginning Balance	-	-	-	-	-	-	-	-	-	-	325,740	990,043	-
	Depreciation Expense	-	-	-	-	-	-	-	-	-	325,740	664,303	700,457	1,690,500
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	-	-	-	-	-	-	-	-	-	325,740	990,043	1,690,500	1,690,500

All wind projects will have a 25 year initial life and a negat
Sherco solar will have a proposed 35 year life and zero pe

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 7 of 8

		2024												
Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Blazing Star II Wind	Plant Beginning Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018	338,745,018
	Reserve Beginning Balance	44,161,020	45,406,877	46,652,735	47,898,592	49,144,449	50,390,307	51,636,164	52,882,022	54,127,879	55,373,737	56,619,594	57,865,452	44,161,020
	Depreciation Expense	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	1,245,857	14,950,289
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	45,406,877	46,652,735	47,898,592	49,144,449	50,390,307	51,636,164	52,882,022	54,127,879	55,373,737	56,619,594	57,865,452	59,111,309	59,111,309
Dakota Range Wind	Plant Beginning Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960	388,122,960
	Reserve Beginning Balance	35,099,242	36,528,828	37,958,415	39,388,001	40,817,587	42,247,173	43,676,760	45,106,346	46,535,932	47,965,518	49,395,105	50,824,691	35,099,242
	Depreciation Expense	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	1,429,586	17,155,035
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	36,528,828	37,958,415	39,388,001	40,817,587	42,247,173	43,676,760	45,106,346	46,535,932	47,965,518	49,395,105	50,824,691	52,254,277	52,254,277
Freeborn Wind	Plant Beginning Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848	327,286,848
	Reserve Beginning Balance	37,796,060	38,999,985	40,203,910	41,407,836	42,611,761	43,815,686	45,019,612	46,223,537	47,427,462	48,631,388	49,835,313	51,039,238	37,796,060
	Depreciation Expense	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	1,203,925	14,447,104
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	38,999,985	40,203,910	41,407,836	42,611,761	43,815,686	45,019,612	46,223,537	47,427,462	48,631,388	49,835,313	51,039,238	52,243,163	52,243,163

Northern States Power Company
New or Revised Depreciation Remaing Lives Due to Additions
2021-2024 Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 7
Page 8 of 8

								2024						
Plant	Category	January	February	March	April	May	June	July	August	September	October	November	December	YTD Summary
Mower Wind	Plant Beginning Balance	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533	223,988,533
	Reserve Beginning Balance	85,590,061	86,190,375	86,790,688	87,391,002	87,991,315	88,591,628	89,191,942	89,792,255	90,392,568	90,992,882	91,593,195	92,193,508	85,590,061
	Depreciation Expense	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	600,313	7,203,760
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	86,190,375	86,790,688	87,391,002	87,991,315	88,591,628	89,191,942	89,792,255	90,392,568	90,992,882	91,593,195	92,193,508	92,793,822	92,793,822
Northern Wind	Plant Beginning Balance	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516
	Plant Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516	224,995,516
	Reserve Beginning Balance	9,361,680	10,111,665	10,861,650	11,611,635	12,361,620	13,111,605	13,861,591	14,611,576	15,361,561	16,111,546	16,861,531	17,611,516	9,361,680
	Depreciation Expense	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	749,985	8,999,821
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	10,111,665	10,861,650	11,611,635	12,361,620	13,111,605	13,861,591	14,611,576	15,361,561	16,111,546	16,861,531	17,611,516	18,361,501	18,361,501
Sherco Solar	Plant Beginning Balance	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	595,661,403	601,790,253	303,994,870
	Plant Additions	-	-	-	-	-	-	-	-	-	291,666,534	6,128,849	7,999,166	305,794,548
	Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Plant Ending Balance	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	303,994,870	595,661,403	601,790,253	609,789,418	609,789,418
	Reserve Beginning Balance	1,690,500	2,414,286	3,138,072	3,861,859	4,585,645	5,309,432	6,033,218	6,757,005	7,480,791	8,204,578	9,275,581	10,701,097	1,690,500
	Depreciation Expense	723,786	723,786	723,786	723,786	723,786	723,786	723,786	723,786	723,786	1,071,003	1,425,516	1,442,335	10,452,933
	Reserve Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
	Cost of Removal	-	-	-	-	-	-	-	-	-	-	-	-	-
	Salvage	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gain or loss	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Transfers & Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reserve Ending Balance	2,414,286	3,138,072	3,861,859	4,585,645	5,309,432	6,033,218	6,757,005	7,480,791	8,204,578	9,275,581	10,701,097	12,143,432	12,143,432

All wind projects will have a 25 year initial life and a negat
Sherco solar will have a proposed 35 year life and zero pe

Northern States Power Company
Theoretical Reserve Amortization Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 8
Page 1 of 2

	Theoretical Reserve Surplus Amortization Expense			
Year	**Transmission**	**Distribution**	**General**	**Total**
2013	$ (18,699,675)	$ (13,670,294)	$ (284,887)	$ (32,654,856)
2014	(65,448,862)	(47,846,029)	(654,888)	(113,949,778)
2015	(39,269,317)	(28,707,618)	(831,789)	(68,808,723)
2016	(26,179,545)	(19,138,412)	(507,531)	(45,825,487)
2017	3,540,580	5,614,908	250,945	9,406,433
2018	3,540,580	5,614,908	250,945	9,406,433
2019	3,540,580	5,614,908	250,945	9,406,433
2020	3,543,597	5,614,211	245,422	9,403,229
2021	3,543,593	5,614,211	245,449	9,403,252
2022	3,543,593	4,743,944	183,580	8,471,117
2023	3,543,593	4,632,108	104,006	8,279,707
2024	3,543,593	4,632,108	88,002	8,263,703
2025	3,543,593	4,632,108	37,667	8,213,369
2026	3,543,593	4,632,108	37,611	8,213,312
2027	3,543,593	4,632,108	37,611	8,213,312
2028	3,543,593	4,632,108	37,611	8,213,312
2029	3,543,593	4,632,108	37,611	8,213,312
2030	3,543,593	4,261,892	37,613	7,843,098
2031	3,543,593	3,116,934	37,613	6,698,141
2032	3,543,593	3,116,934	37,613	6,698,141
2033	3,543,593	3,116,934	37,613	6,698,141
2034	3,543,593	3,033,131	37,613	6,614,337
2035	3,543,593	3,018,064	37,613	6,599,270
2036	3,543,593	2,832,992	37,613	6,414,198
2037	3,543,593	2,399,593	37,613	5,980,799
2038	3,543,593	2,399,593	37,613	5,980,799
2039	3,543,593	2,399,593	37,613	5,980,799
2040	3,543,593	2,399,593	37,613	5,980,799
2041	3,543,593	2,399,593	37,613	5,980,799
2042	3,543,593	2,281,057	37,613	5,862,264
2043	3,543,593	2,070,775	37,613	5,651,981
2044	3,543,593	766,783	37,613	4,347,989
2045	3,543,593	577,324	37,613	4,158,531
2046	3,543,593	577,324	37,613	4,158,531
2047	3,543,593	577,324	37,613	4,158,531
2048	3,543,593	577,324	37,613	4,158,531
2049	3,543,593	577,324	28,682	4,149,600
2050	3,543,593	498,577	(43,721)	3,998,449
2051	3,543,593	399,660	(43,721)	3,899,533
2052	3,543,593	398,270	(43,721)	3,898,142
2053	3,165,971	323,917	(43,721)	3,446,167
2054	2,955,111	-	(43,721)	2,911,391
2055	2,955,111	-	(43,721)	2,911,391
2056	2,435,652	-	(9,325)	2,426,327

Northern States Power Company
Theoretical Reserve Amortization Summary

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 8
Page 2 of 2

	Theoretical Reserve Surplus Amortization Expense			
Year	**Transmission**	**Distribution**	**General**	**Total**
2057	1,295,414	-	-	1,295,414
2058	1,270,938	-	-	1,270,938
2059	1,270,938	-	-	1,270,938
2060	1,270,938	-	-	1,270,938
2061	1,270,938	-	-	1,270,938
2062	1,270,938	-	-	1,270,938
2063	1,270,938	-	-	1,270,938
2064	829,786	-	-	829,786
2065	696,329	-	-	696,329
2066	34,239	-	-	34,239
2067	16,681	-	-	16,681
2068	16,681	-	-	16,681
2069	10,482	-	-	10,482
Total	$ 0	$ 0	$ 0	$ 0

Note: Amounts represented herein are the Minnesota jurisdictional amounts of the theoretical reserve surplus. 2013-2016 represents the amortization of the theoretical reserve surplus which decreased depreciation expense and built up a regulatory asset. 2017-2069 represents the amortization of the regulatory asset which effectively moves the regulatory asset balance back into accumulated depreciation while being income statement neutral.

Northern States Power Company
End of Life Nuclear Fuel Accruals

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 9
Page 1 of 1

in whole $

	Nuclear Fuel Accumulated Reserve per E,002/GR-15-826						Forecast Reserve balance included in 2021 Bridge Year
Nuclear Fuel Type	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Nuclear Fuel	$ 2,010,208,866.09	$ 2,126,722,658.09	$ 2,241,578,245.09	$ 2,362,194,893.09	$ 2,484,350,097.09	$ 2,610,102,891.09	2,699,417,031.82
Nuclear Fuel EOL	$ 54,877,255.55	$ 57,595,315.55	$ 60,490,219.55	$ 63,573,487.55	$ 66,857,383.55	$ 70,354,963.55	73,211,719.56
Total	**$ 2,065,086,121.64**	**$ 2,184,317,973.64**	**$ 2,302,068,464.64**	**$ 2,425,768,380.64**	**$ 2,551,207,480.64**	**$ 2,680,457,854.64**	**$ 2,772,628,751.38**
Cost of Service Nuclear Fuel Accumulated Reserve	**$ 2,065,086,121.64**	**$ 2,184,317,973.64**	**$ 2,302,068,464.64**	**$ 2,425,768,380.64**	**$ 2,551,207,480.64**	**$ 2,680,457,854.64**	**$ 2,772,628,751.38**
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	2016	2017	2018	2019	2020	2021
Year over Year Change in Nuclear Fuel EOL	$ 2,718,060.00	$ 2,894,904.00	$ 3,083,268.00	$ 3,283,896.00	$ 3,497,580.00	$ 2,856,756.01
Approved Nuclear Fuel EOL Accrual per E,002/M-14-761 (starting 2016) and E,002/M-17-828 (starting 2021)	2,718,060.00	2,894,917.75	3,083,283.22	3,283,905.18	3,497,581.14	2,856,756.00
Difference (Rounding)	$ -	$ (13.75)	$ (15.22)	$ (9.18)	$ (1.14)	$ 0.01

Amounts shown are at Total Company

Northern States Power Company
Excess ADIT Roll-forward

Docket No. E002/GR-21-630
Exhibit___(MPM-1), Schedule 10
Page 1 of 2

Excess Deferred Taxes Roll-forward NSPM 2021-2024	**2021 Beginning Balance**	**2021 ARAM**	**2021 Ending Balance**	**2022 ARAM**	**2022 Ending Balance**	**2023 ARAM**	**2023 Ending Balance**	**2024 ARAM**	**2024 Ending Balance**
Common (Unallocated)	18,365,859	(4,125,819)	14,240,040	(3,342,757)	10,897,283	(2,643,342)	8,253,942	(2,232,679)	6,021,262
Electric Distribution	215,274,318	(5,998,978)	209,275,341	(5,810,568)	203,464,772	(5,856,794)	197,607,978	(6,315,028)	191,292,950
Electric General	21,753,950	(2,850,747)	18,903,203	(2,773,181)	16,130,022	(2,740,426)	13,389,596	(2,531,559)	10,858,036
Electric Intangible	823,043	(241,351)	581,692	(262,129)	319,562	(240,340)	79,222	(95,622)	(16,400)
Electric Production	369,776,910	(25,946,613)	343,830,297	(21,077,103)	322,753,194	(21,559,227)	301,193,966	(23,939,917)	277,254,050
Electric Transmission	243,564,155	(2,865,612)	240,698,542	(2,951,599)	237,746,944	(3,315,566)	234,431,378	(3,663,223)	230,768,155
Electric Transmission-Production	4,652,741	(82,205)	4,570,536	(77,756)	4,492,780	(88,849)	4,403,932	(106,446)	4,297,485
Nuclear Fuel	(5,403,589)	(2,366,071)	(7,769,660)	(377,553)	(8,147,213)	(11)	(8,147,224)	(0)	(8,147,224)
Total	868,807,388	(44,477,397)	824,329,991	(36,672,647)	787,657,344	(36,444,556)	751,212,788	(38,884,475)	712,328,313
Common (Allocated to Other Segments)	(1,600,391)	359,522	(1,240,869)	291,286	(949,583)	230,339	(719,244)	194,554	(524,690)
Electric (w/ Common Allocated)	867,206,997	(44,117,875)	823,089,122	(36,381,361)	786,707,761	(36,214,216)	750,493,544	(38,689,921)	711,803,624

Average Rate Assumption Method (ARAM)

Change in Tax Rate - Before ADIT Set Up is Complete

Plant Asset = $100

Year	Tax Depreciation	Book Depreciation	Timing Difference	Tax Rate		Deferred Expense	ADIT
	(A)	(B)	(A)-(B)= (C)	(D)		(C)*(D)=(E)	
1	40	10	30	35%		11	11
2	30	10	20	21%	(1)	4	15
3	15	10	5	21%		1	16
4	10	10	-	29%	(2)	-	16
5	5	10	(5)	29%	(2)	(1)	14
6	-	10	(10)	29%	(2)	(3)	11
7	-	10	(10)	29%	(2)	(3)	9
8	-	10	(10)	29%	(2)	(3)	6
9	-	10	(10)	29%	(2)	(3)	3
10	-	10	(10)	29%	(2)	(3)	-
	100	100	-			-	

(1) Tax rate change from 35% to 21% occurs in Year 2 of asset's life.

(2) Average rate is used to unwind deferred tax liability over remaining life of asset. This is an average of the 35% and 21% rates used to calculated deferred tax expense for the years when tax depreciation was greater than book depreciation.

Change in Tax Rate - After ADIT Set Up is Complete

Plant Asset = $100

Year	Tax Depreciation	Book Depreciation	Timing Difference	Tax Rate		Deferred Expense	ADIT
	(A)	(B)	(A)-(B)= (C)	(D)		(C)*(D)=(E)	
1	40	10	30	35%		11	11
2	30	10	20	35%		7	18
3	15	10	5	35%		2	19
4	10	10	-	21%		-	19
5	5	10	(5)	35%	(1), (2)	(2)	18
6	-	10	(10)	35%		(4)	14
7	-	10	(10)	35%		(4)	11
8	-	10	(10)	35%		(4)	7
9	-	10	(10)	35%		(4)	4
10	-	10	(10)	35%		(4)	-
	100	100	-			-	

(1) Tax rate change from 35% to 21% occurs in Year 5 of asset's life, when book depreciation is greater than tax depreciation and the ADIT balance is unwinding.

(2) Average rate is used to unwind deferred tax liability over remaining life of asset, which is 35% since the tax rate change occured after the ADIT balance had finished setting up.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of Northern States Power Company, d/b/a Xcel Energy's Petition for Approval of the 2022 Annual Review of Remaining Lives (ARL) and Depreciation Rates for Electric and Gas Production and Gas Storage Facilities (EGPS) & for Transmission, Distribution, and General Accounts (TDG) & Five-Year Transmission, Distribution, and General Depreciation Study

ISSUE DATE: January 9, 2024

DOCKET NO. E,G-002/D-22-299

ORDER APPROVING PETITION WITH MODIFICATIONS AND SETTING ADDITIONAL FILING REQUIREMENTS

PROCEDURAL HISTORY

On September 8, 2022, Northern States Power Company, d/b/a Xcel Energy (Xcel or the Company) filed a Petition for annual review of remaining lives and depreciation rates for electric and gas production and gas storage facilities.

On September 12, 2022, Xcel filed a Petition for annual review of remaining lives and depreciation rates for transmission, distribution, and general accounts.

On November 10, 2022, Xcel filed its five-year transmission, distribution, and general distribution study (Five-Year Study).

On March 8, 2023, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed comments.

On March 13, 2023, the Office of the Attorney General—Residential Utilities Division (OAG) filed comments.

On March 23, 2023, Xcel filed reply comments.

On April 11, 2023, the Department filed comments.

On April 28, 2023, Xcel filed supplemental reply comments.

On August 18, 2023, the Department filed supplemental comments.

On October 26, 2023, the Commission met to consider this matter.

FINDINGS AND CONCLUSIONS

I. Introduction

Depreciation accounting aims to systematically and rationally distribute the costs of capital assets, less salvage, over those assets' useful lives.[1] It is a process of allocation, not of valuation. Each utility is responsible for proposing the depreciation rates and methods that will be used, and the Department reviews whether the utility's proposed methods are appropriate. The Commission is required to issue an order certifying the depreciation rates and methods it considers reasonable and proper.[2]

At least once every five years, a utility must file a petition for depreciation certification that includes data and analyses of various relevant factors to justify the utility's depreciation rates and methods.[3] In addition to the petition itself, utilities must also file depreciation schedules for plant in service,[4] analysis of depreciation reserve,[5] and a summary of annual depreciation accruals.[6]

The Department examined Xcel's filings in this docket for reasonableness and analyzed Xcel's proposed changes to the depreciation parameters (lives and salvage rates), theoretical reserve, and Xcel's proposed new FERC accounts. In addition, the Department reviewed the filings for compliance with applicable statutes, rules, and prior Commission orders.

A. Xcel's Initial Filings

Xcel made three initial filings in this docket. First, it filed a petition for approval of its 2022 annual review of remaining lives for electric and gas production and gas storage facilities and requested approval of the following:

- Passage-of-time adjustments for electric and natural gas production and gas storage facilities;
- Modification to the remaining lives for electric production plants: Allen S. King Generating Station (King), Sherburne County Generating Station Unit 3 (Sherco 3), Blue Lake Units 1–4, Grand Meadow Wind, and Nobles Wind;
- Modification to the remaining lives for Maplewood and Sibley Gas Production and the Wescott Gas Storage facility; and

[1] *See* Minn. R. 7825.0500, subp. 7.

[2] *See* Minn. R. 7825.0600, subp. 1.

[3] *See* Minn. R. 7825.0700.

[4] Plant in service depreciation schedules include: beginning and ending plant balances; additions and retirements; and adjustments and transfers.

[5] Analysis of depreciation reserve schedules include: beginning and ending reserve balances; depreciation accruals and plant retirements; cost of removal and gross salvage value; transfers, and adjustments/other debits (credits).

[6] Summary of annual depreciation accruals schedules include: plant balance; estimated net salvage; depreciation reserve; probable service life; and depreciation accrual and rate.

- Initial remaining lives and net salvage rates for Northern Wind and Rock Aetna wind facilities.

Second, Xcel filed its annual update of remaining lives and depreciation rates for its transmission, distribution, and general accounts requesting approval of the following:

- Updated depreciation rates effective January 1, 2023;
- The addition of new sub-accounts for gas utility software and corresponding lives, depreciation rates, and net salvage rates; and
- The addition of new electric utility accounts and corresponding lives, depreciation rates, and net salvage rates.

Xcel's third filing contained its Five-Year Study that reviewed and updated depreciation data for transmission, distribution, and general plant for the Company's electric, gas, and common utilities. Xcel proposed new depreciation lives and rates that better reflect the expected useful lives of assets as well as removal costs and expected salvage. Overall, depreciation lives remained relatively the same, but net negative salvage rates were higher due to increasing removal costs and decreasing gross salvage values. Additionally, the study recommended a reserve reallocation within the functional classes to better align the accumulated depreciation reserve for each account.[7] In the aggregate, the proposed changes increased the Company's present depreciation costs by approximately $12.25 million.

Primarily at issue in this case is Xcel's request to defer implementation of the updated depreciation expense until the changes can be incorporated into future rate proceedings.

II. Depreciation Lives, Salvage, and Accrual Rates

A. Positions of the Parties

After conducting a thorough review of Xcel's initial filings and updated data, the Department recommended approval of Xcel's proposed five-year accrual rates, resulting in an annual estimated depreciation expense increase for transmission, distribution and general of $12,711,918.

According to the Department, both Xcel's proposed average service lives and theoretical reserve were reasonable and warranted Commission approval. Furthermore, the Department agreed with Xcel's proposal to redistribute its existing depreciation reserves by functional class to better align each account's theoretical reserve with the new, proposed depreciation parameters. The Department also stated that it did not dispute that the historical salvage and removal costs reported in Xcel's Five-Year Study accurately represented the Company's actual, historical salvage and removal costs. Consequently, the Department stated that Xcel's reliance on its historical experience to inform the proposed salvage rates was reasonable for the purpose of calculating annual depreciation expense.

[7] Reallocation rebalances the actual reserve where one account is in surplus and another is in deficit.

B. Commission Action

Xcel and the Department both recommended approval of the depreciation lives, salvage rates, and accrual rates which are estimated to result in an increase in annual depreciation expense of $12,711,918. The Commission finds that the methodology and rationale justifying these proposed parameters are reasonable and will approve the updates as recommended by the Department and Xcel.

III. Deferred Implementation

The Company stated that due to the timing of ongoing rate case proceedings, it would be unable to fully recover its estimated $12.7 million annual depreciation expense increase in 2023 and 2024 without either deferring implementation of the increase or modifying its capital true-up in the electric rate case. Although the Company did not offer an estimate of what portion of costs would be subject to under-recovery, the Company requested that the Commission allow the Company to defer implementation of the increase until its next general rate case.

A. Positions of the Parties

1. Xcel

Xcel stated that the timing of its Five-Year Study created procedural complexity due to the Company's ongoing rate case proceedings[8] that utilized depreciation assumptions that did not align with the results of the Five-Year Study. Xcel argued that the Commission should defer any changes related to the study to future rate case proceedings so that the changes could be applied without benefiting customers or shareholders. According to Xcel, its deferral proposal is fair to both shareholders and ratepayers because it allows the Company to recover its actual depreciation costs, and it will not harm current or future customers. Alternatively, if the Commission orders implementation of depreciation expense changes on January 1, 2023, Xcel suggested modifying the capital true-up in the ongoing electric rate case to enable recovery of the updated depreciation expense.

a. Recovery of Costs

Although Xcel recognized that differences between rate case depreciation expense and approved depreciation studies are not typically tracked, it argued that the currently estimated mismatch of approximately $12.7 million annually would have a significant impact that justifies special treatment. Without the special treatment, Xcel stated that it would be incentivized to significantly reduce its overall capital investment to align with budgets set through the ratemaking process, which would require significant departures from planned capital investments and not further the interests of the Company or its customers. [9]

[8] *See In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630; *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-002/GR-21-678.

[9] Although the Department disputed that Xcel would be required to fully offset the increased depreciation expense solely by reducing capital investments, the Department contended that the $12.7 million increase would be offset by an annual $115 million capital investment reduction.

b. Impacts on Ratepayers

Xcel asserted that its deferral proposal will not unfairly harm customers and dismissed the intergenerational equity concerns expressed by the Department as overstated because every adjustment to depreciable expenses has the potential to result in some intergenerational cost shifts. Xcel argued that rather than focusing on the potential for intergeneration cost-shifting, the Commission should focus on the impact of the proposed deferrals on customers and whether it is reasonable under the circumstances. Xcel stated that its proposal only allows it to recover the prudent costs it has already incurred to provide service to customers. To the extent the proposal would create intergenerational cost-shifting, the rate impacts would be minimal because the impacts will be spread over the remaining lives of Company assets. Xcel also noted its proposal would not impact rates until its next rate case when the results of the study would be incorporated into the Company's depreciation expense—at that time, the Commission would have the opportunity to consider any capital additions and rate mitigation strategies that may be necessary to minimize ratepayer impact.

c. Capital True-Up Alternative

Xcel explained that it proposed a capital true-up in its electric rate case that only results in a refund if the test-year capital costs exceed actual-year capital costs, so depreciation expense decreases can be captured outside of a rate case to protect ratepayers. Because the true-up does not address depreciation expense increases such as those at issue here, Xcel proposed to modify the capital true-up mechanism to allow the Company to remove the impact of the updated depreciation expenses from any actual year if the Company is not otherwise obligated to issue a capital true-up refund.[10] Xcel suggested combining this adjustment to the capital true-up against refunds due for any other annual compliance filing in the final rate case determination, and the Company would issue a refund to customers for a net refund—if any uncollected depreciation expense remains, Xcel proposed deferring any remaining amount to any future-year compliance refund until the next rate case. If this amount is not offset by other compliance refunds, Xcel requested approval to include an amortization proposal for the balance in its next rate case.

B. The Department

The Department opposed deferring the proposed depreciation expense to future rate case proceedings. As an initial matter, the Department disputed Xcel's assertion that the deferral proposal simply allows the Company to recover its prudent, actual costs. Although the Department accepted the depreciation study's results as they relate to the determination of depreciation rates, it contended that Xcel failed to substantiate that its depreciation costs—particularly the net salvage expense—are reasonable and prudent.

The Department noted that for several plant accounts with significant net salvage expense, both the current and proposed net salvage rates were notably lower than those indicated by recent, actual data. As examples, the Department specifically referenced electric plant accounts 364 and 367 but noted that similar discrepancies were also present in other plant accounts. The

[10] Xcel noted its true-up alternative would address the increased depreciation expense for its electric utility; however, because no similar mechanism exists for gas depreciation expense, the Company recommended that it work with the Department and Commission to determine how to best address gas depreciation expense in the future.

Department estimated that approximately $12 million of the $12.7 million increase in total depreciation expense is attributable to the proposed changes in salvage rates. Given the significant contribution of the proposed salvage rates to the increased depreciation expense and the Department's expectation that net salvage expenses may be an ongoing issue as the Company seeks cost recovery for anticipated future increases, the Department asked Xcel to explain the drivers of the Company's net salvage expense.

The Department asserted that it provided Xcel multiple opportunities to produce meaningful explanations or supplemental data that would allow the Department to adequately assess the Company's net salvage expense; however, Xcel failed to provide meaningful data. Instead, the Department noted that Xcel provided anecdotal explanations that applied to the broader utility industry, but these explanations were not necessarily applicable to Xcel.[11] The Department expressed concern about Xcel's inability to provide a meaningful explanation of its increasing net salvage expense, particularly due to Xcel's proposal to defer the depreciation expense increase to future rate case proceedings.

According to the Department, Xcel has proposed to hold itself financially harmless by delaying the recognition of the incremental portion of its annual depreciation expense that it would otherwise normally recognize on its income statement until future accounting periods when it can synchronize the expense with an offsetting revenue increase. The Department contended that the ultimate impact of Xcel's proposal would be nearly identical to the outcome achieved through deferred accounting. Due to these similarities and Xcel's failure to meet the high bar necessary to justify deferred accounting and depart from normal regulatory practice, the Department argued that the Commission should reject Xcel's deferral proposal and true-up alternative.

The Department asserted that deferred accounting is an extraordinary remedy that is authorized sparingly and reserved for large, unusual, and unforeseen expenses. The Department noted that depreciation expense is a large, significant, well-known expense that is subject to regular (often annual) proceedings before the Commission. Because depreciation rates regularly change as a result of these proceedings, the Department contended that neither depreciation expense generally, nor changes to depreciation expense specifically, can reasonably be described as unusual. The Department also argued that Xcel has a great deal of visibility into its net salvage expense, and because approximately $12 million of the $12.7 increase is attributable to the proposed net salvage rates, Xcel could and should have known that an increase in net salvage expense was likely.

[11] For example, the Department noted that Xcel provided Bureau of Labor Statistics data showing that the average hourly earnings of non-supervisory construction workers increased from 2013–2023, which the Department agreed supported a claim that labor costs have generally increased across the construction industry. However, the Department contended that it was unclear how this data applied to utilities generally or Xcel specifically, and the Department noted that this data does not clarify what percentage of Xcel's overall net salvage expense relates to labor versus other operational and maintenance costs. Similarly, the Department requested accounting records related to the net salvage expense of a specific plant account incurred during 2021, and Xcel provided what the Department described as "only very high-level summary information that provided no clarity regarding the proposed increase in net salvage for the account." According to the Department, when it again asked for specific accounting records and documentation related to the account's 2021 net salvage expense, Xcel provided no accounting records or documentation in its response.

While the Department recognized that the magnitude of the depreciation expense increase may be above average for a depreciation docket, it argued that the expense will not have a significant financial impact on Xcel's electric or gas utilities. The Department contextualized the estimated $12.7 million increase as representing a 3.0% increase relative to current depreciation rates, which represents 1.5% and 2.7% of the electric and gas utilities' respective 2022 net operating income. The Department estimated that increases of these magnitudes would have lowered the utility's actual, weather-normalized return on equity by 14 basis points for electric and 19 basis points for gas. The Department asserted that such changes are well within the range of variation of the utilities' actual, weather-normalized return on equity over the past five years.

The Department also contended that deferred accounting and other similar mechanisms may potentially involve problematic single-issue ratemaking or create intergenerational inequity, and it is therefore inappropriate to employ these mechanisms to remedy ordinary cost fluctuations that occur between rate cases.

C. Commission Action

Although Xcel's proposal to defer implementation of the updated depreciation expense to future rate cases is not an explicit request to authorize deferred accounting, the proposal is an extraordinary remedy that would create similar impacts. The Commission is unpersuaded that the current record justifies granting Xcel's request to deviate from standard practices.

Xcel filed its Five-Year Study after it began litigating its rate cases, and rate-case determinations did not rely on the results of the new study. Because the determinations in those rate cases relied on less-current depreciation expense data, Xcel contends that it should be allowed to postpone implementation of its proposed depreciation expense until it can be addressed in future rate cases. However, utilities have discretion to decide if and when they file a rate case. While utilities are required to file a comprehensive depreciation study at least every five years, they may time the filing of each petition to allow for the incorporation of the most-current five-year study into the record of the rate case. Xcel was unable to produce its Five-Year Study to allow the results to be evaluated during the rate cases.

As noted by the Department, rate case proceedings allow parties to consider capital additions and rate-mitigation strategies that can account for potential rate impacts created by changes to depreciation rates, but the differences between the depreciation rates in a rate case and those approved in a certified study are not typically tracked. Xcel's decisions to petition for rate increases without certainty that it would be able to incorporate the results of a new five-year study into those cases do not justify shifting the costs of current depreciation expenses to future ratepayers.[12]

Accordingly, the Commission finds that Xcel has not sufficiently demonstrated good cause to justify its proposal to defer implementation of the updated depreciation expense, and the Commission will require Xcel to implement the changes to depreciation rates effective January 1, 2023.

[12] The Department estimated that approximately $12 million of the $12.7 million total depreciation-expense increase is attributable to proposed changes in net salvage rates—Xcel could and should have been cognizant of its increasing net salvage expense and the potential for the increase to impact rates.

IV. Passage-of-Time Adjustment

Xcel proposed a two-year passage-of-time adjustment to the 2021 certified remaining lives of all facilities, resulting in proposed remaining lives as of January 1, 2023. Xcel noted that this adjustment does not change previously approved depreciation rates but reflects the two-year period that has passed from January 1, 2021 to January 1, 2023, the effective date of the requested depreciation rates. The Department stated that Xcel's proposed two-year passage of time adjustment and implementation date of January 1, 2023, are reasonable.

The Commission finds that Xcel's proposal reasonably reflects that two years have elapsed since the effective date of the previously approved depreciation rates and will approve a two-year passage-of-time adjustment for all natural gas and electric production and gas storage facilities with an implementation date of January 1, 2023.

V. Changes to Remaining Lives

Xcel requested approval of changes to the remaining lives of eight facilities, which would result in a net increase in total Company depreciation and amortization expense of approximately $48 million for existing assets. Xcel noted that the expense impact reflects changes to the lives of assets that were not included in interim rates of the Company's recent gas and electric rate cases. Xcel's requested changes are reflected below in Table 1.

Table 1

Plant	Current Retirement Date	Proposed Retirement Date
Allen S. King	June 2037	December 2028
Sherco Unit 3	December 2034	December 2030
Grand Meadow Wind	November 2033	November 2043
Nobels Wind	November 2035	November 2045
Blue Lake Units 1–4		
E341 E342–E346	May 2045 June 2023	May 2045 December 2025
Maplewood	December 2029	December 2041
Sibley	December 2029	December 2041
Wescott		
G361–G363.1 G363.2 G363.3 G363.4–G363.5	December 2023 December 2027 December 2032 December 2023	December 2041 December 2041 December 2041 December 2041

The Department noted that as an asset is used in operations, it contributes, either directly or indirectly, to an entity's cash flows. Depreciation is the method of cost allocation that allows an entity to better match the revenues generated by an asset with the cost of the asset over its useful life. Therefore, the Department contended that an asset's depreciable life should be aligned with when the asset is used and useful.

Because modifying the remaining life of an asset directly affects the asset's depreciation expense, the Department asserted that a request to extend or reduce the remaining life of an asset should be supported with verifiable operational expectations that justify the modification. Depending on whether additional capital expenditures are applied to an asset, extending the asset's remaining life has the potential to impact all or a combination of the annual depreciation expense, total depreciable costs, and capital asset balance for the period of time over which the asset is depreciated.

The Department agreed with Xcel and noted that the $47.8 million increase in depreciation expense is driven by changes to King, Sherco 3, and Blue Lake Units 1–4, which were not included in interim rates for Xcel's pending rate cases. The Department recommended approval of Xcel's requested remaining lives changes because the modified retirement dates better reflect these assets' useful lives.

The Commission agrees with the Department and finds that Xcel's requested changes are reasonable. Therefore, the Commission will approve the proposed remaining lives changes as reflected in Table 1.

VI. Changes to Depreciation Lives

A. King and Sherco 3

1. Positions of the Parties

Xcel noted that the Commission's order in the Company's recent Integrated Resource Plan (IRP) approved accelerated retirements of the coal-powered King and Sherco 3 plants.[13] Xcel requested approval of updated remaining lives for these facilities consistent with their new retirement dates.

The Department noted that Xcel's requested reduction of remaining lives for King and Sherco 3 increases depreciation expense by a combined total of $49.73 million. The Department recommended approval of Xcel's request.

The OAG stated that Xcel had proposed a change in its depreciation rates during its ongoing general rate case where the Company argued that the depreciation lives of King and Sherco 3 should align with the retirement schedules approved in its IRP. However, the OAG contended that Xcel first made the proposal in rebuttal testimony, which did not allow for sufficient record development to address possible alternative rate treatments for early-retired coal plants (such as securitization), analyses of the extent to which the risk of early plant closures are compensated through Xcel's approved rate of return, and the prudence of the Company's decision to continue investing in coal plants. According to the OAG, the record in this docket contains similar deficiencies. Rather than resolve these issues on an inadequate record, the OAG recommended that the Commission address them in a separate docket that will provide a better record to inform any Commission action.

[13] *See In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings at 7, 31, Ordering Para. 2.A.4 (April 15, 2022).

2. Commission Action

Consistent with the decision in Xcel's electric rate case, the Commission will reserve a decision on the depreciation lives of King and Sherco 3 until the issue is addressed in the recently opened docket examining ratemaking treatment for early-retired coal plants.[14]

B. Northern Wind and Rock Aetna

1. Positions of the Parties

The Department recommended 35-year initial depreciation lives for Northern Wind (Northern) and Rock Aetna. The Department noted that this outcome would be consistent with treatment in other dockets that have recently addressed this issue, including Xcel's most-recent electric rate case where the Company agreed to extend the lives of several wind projects from 25 to 35 years.

Xcel stated that its petition assumed 25-year life depreciation for all wind facilities because depreciation schedules based on 25-year lives have traditionally applied to wind facilities. Xcel explained that although it supported the application of 35-year lives for certain windfarms during its rate case, because Northern and Rock Aetna are repowered windfarms, a 25-year period would better reflect their useful lives. Northern and Rock Aetna are recent acquisitions that the Company did not include in its rate case, so Xcel stated that it would recover rates for both facilities through the Renewable Energy Standard Rider. Despite initially advocating for 25-year initial depreciation lives for repowered wind facilities, Xcel acknowledged that the Commission had recently set 35-year lives for wind facilities and doing so here would be consistent with those decisions. By the time the Commission met, Xcel did not oppose setting 35-year initial depreciation lives for Northern and Rock Aetna.

2. Commission Action

The Commission will approve 35-year initial depreciation lives for Northern and Rock Aetna. This decision is reasonable and consistent with the Commission's recent treatment of other wind-powered generation facilities.

C. Blue Lake Peaking Plant Units 1–4

1. Positions of the Parties

Xcel requested to extend the life of the Blue Lake Peaking Plant Units 1 through 4 (Blue Lake 1–4) from the currently approved retirement date of June 2023 to December 2025.

The Department supported the requested 1.5-year extension of the depreciation life for Blue Lake 1–4. The Department noted that the requested depreciation-life extension would decrease annual depreciation expense by $1.9 million. Although tracking the decrease in depreciation expense would benefit ratepayers, the Department opposed doing so because, except in very limited circumstances not currently present, these types of changes are not tracked.

[14] *See In the Matter of a Commission Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities*, Docket No. E-002, E-015, E-017/CI-23-375.

2. Commission Action

The Commission agrees with the rationale provided by the Department supporting its recommendation to grant Xcel's life-extension request for Blue Lake 1–4 and not track the resulting depreciation expense decrease. Based on the record, the 1.5-year life extension is reasonable, and the type of impact created by the approved change is not typically tracked outside of a rate case.

D. Maplewood and Sibley Peaking Plants

1. Positions of the Parties

Due to the results of Xcel's hazard and operability and layer-of-protection study that recommended additional investments in the Maplewood and Sibley peaking plants' vaporization systems that were at the end of their life expectancies, Xcel made recent capital investments in the two plants. Xcel contended that the capital expenditures in these facilities will allow for their safe operation and extend the operational life expectancies beyond their current lives. Xcel proposed a 12-year extension for these facilities. Because the interim rates in its gas rate case reflected the resulting reduction in depreciation expense, Xcel requested that the proposed changes to remaining life and depreciation impact become effective as of January 2022.

The Department recommended approval of Xcel's proposal.

2. Commission Action

The Commission finds that Xcel's proposed 12-year extension of the depreciation lives of the Maplewood and Sibley peaking plants is reasonable and will authorize 12-year extensions from the current retirement date of December 2029.

VII. Major Future Additions and Retirements

A. Positions of the Parties

Xcel proposed five new categories of assets with corresponding average service lives, net salvage percentages, and depreciation rates. These categories are: (1) gas utility seven-year software; (2) gas utility fifteen-year software; (3) energy storage equipment – transmission; (4) energy storage equipment – distribution; and (5) roads and trails.

1. Gas Utility Software Assets (FERC Account 303)

Xcel explained that it included two sub-categories within its FERC 303 account to appropriately allocate costs related to the gas utility's software assets. The first sub-category would include replacement supervisory control and data acquisition (SCADA) software that the Company uses to capture and assess data in real time from remote locations to control equipment and conditions. The software vendor's standard contract term is seven years, so Xcel proposed that the software be amortized over a seven-year period to match expense with the useful life of the asset. Xcel requested the creation of a new seven-year FERC 303 Gas Utility subaccount with an initial 14.29% depreciation rate, a seven-year average service life, and zero percent net salvage.

The second sub-category is similar, but Xcel would use it for software that has a 15-year useful life. Xcel stated that it does not currently have any assets in this account, but that it requested its inclusion in anticipation of future additions. Xcel requested an initial 6.67% depreciation rate, a 15-year average service life, and zero percent net salvage for this sub-account.

The Department stated that the 7-year sub-account will allow accurate placement of Xcel's new SCADA software while also providing consistency for the 7-year software accounts between the common, electric, and gas utilities. The Department noted that both the common and electric utilities have FERC 303 sub-accounts for 15-year software and that Xcel's proposed account parameters are reasonable and consistent with the electric and common accounts.

The Department recommended approval of both the 7- and 15-year FERC 303 sub-accounts as proposed by Xcel.

2. Energy Storage Equipment (FERC Accounts 351 and 363)

The third and fourth categories Xcel requested relate to energy storage equipment either for electric transmission or distribution; Xcel currently has no assets in either category. Xcel stated that customers have expressed interest in resiliency through a battery energy storage system (BESS). Xcel explained that the primary function of a BESS is to provide backup power to a specific customer during times of unplanned outages or emergencies. During times of reliable grid operations, these systems also have capabilities to provide energy back into the grid for peak shaving, arbitrage, or providing extra power to local feeders as they near their designed maximum load.

FERC Account 351 would be created for BESS transmission assets and FERC Account 363 would be for distribution assets—Xcel explained that each account would have the same types of assets, but designation of the two types of assets is based on whether voltage is at distribution or transmission levels. For each account, Xcel proposed an initial ten percent depreciation rate, a ten-year average service life, and zero percent net salvage.

Xcel stated that the zero percent net salvage is because the cost of removing, relocating, and resettling energy storage equipment would be charged not to these accounts but to other accounts for either operation or maintenance of energy storage equipment. Xcel explained that if it determined that new batteries have material estimated disposal costs that exceed salvage, it would then request that the expense be included as a component of net salvage for the remaining life of the asset. If the assets have been retired, the Company indicated that it would likely request reallocation of reserves consistent with other situations where actual removal costs vary from estimated and recovered costs.

Although the Department did not oppose creation of these accounts, it expressed concern that the zero percent salvage Xcel proposed for these accounts and the Company's plan to shift costs on other assets and future ratepayers would create intergenerational inequities. Given these concerns, the Department recommended that the Commission delay approval of these accounts until Xcel purchases assets and a reasonable net salvage can be determined.

By the time the Commission met, Xcel did not oppose the Department's recommendation.

3. Roads and Trails (FERC Account 359)

Xcel also requested a new FERC 359 electric utility account for roads and trails necessary to access electric transmission assets. Xcel stated that it does not currently have any assets in this account, but that it requested its inclusion in anticipation of future additions. Xcel proposed an initial 1.67% depreciation rate, average service life of 60 years, and zero percent net salvage.

The Department did not raise any objections related to establishing this account and recommended approval of it as proposed by Xcel.

B. Commission Action

The Commission agrees with the Department's rationale related to Xcel's proposed new accounts. Approval of the 7- and 15-year gas utility software sub-accounts will provide consistency of accounts between the common, electric, and gas utilities. Xcel's request for the new FERC 359 account for roads and trails necessary to access electric transmission assets provides a reasonable classification for Xcel's anticipated future additions. Because the parameters related to the gas utility software sub-accounts and the transmission-asset-access roads and trails account are reasonable, the Commission will approve Xcel's proposal to establish these accounts.

The Commission shares the concern expressed by the Department related to the zero percent salvage of the two energy-storage equipment accounts. Rather than approve Xcel's request for these accounts in anticipation of possible future acquisitions, the Commission finds that it is more reasonable to revisit this issue once the Company has more information related to such assets.

VIII. Changes to Future Filing Requirements

A. Schedule K

The Department noted that it faced ongoing challenges evaluating Xcel's requests in this docket because the Company's submissions contained inconsistencies and errors, some of which were created by linkage errors. To avoid potential issues evaluating future depreciation petitions, the Department recommended, and Xcel agreed, that it would be reasonable to include Schedule K – Accumulated Depreciation Linkage Between Schedules in all future five-year filings.

The Commission appreciates the Department's continued efforts to obtain the information necessary to provide informed recommendations based on accurate information and data and concurs that it is reasonable to require Xcel to include Schedule K – Accumulated Depreciation Linkage Between Schedules in all future five-year filings.

B. Cost-of-Removal Study

Xcel explained that it anticipated that the proposed dismantling of the Key City, Granite City, Minnesota Valley, and Black Dog Units 3 and 4 production plants will be fully completed by the time it makes its next remaining-life filing. Therefore, Xcel proposed that the Company complete a full review of its cost-of-removal reserve balances and include it in its next remaining-life filing. The Department did not object to Xcel's proposal and indicated that it would review the final dismantling of these facilities and cost of removal during its evaluation of Xcel's next remaining-life filing.

Given the anticipated timing for dismantling the Key City, Granite City, Minnesota Valley, and Black Dog Units 3 and 4 production plants, Commission finds Xcel's proposal is reasonable. The Commission will require Xcel to include a complete cost-of-removal study in its next five-year filing.

ORDER

1. The Commission approves a two-year passage-of-time adjustment for all natural gas and electric production and gas-storage facilities with an implementation date of January 1, 2023.

2. The Commission approves Xcel's requested changes in remaining lives as presented in Table 1 of the Department's March 8, 2023 comments.

3. The Commission authorizes that the initial depreciation lives for Northern Wind and Rock Aetna be set at 35 years.

4. The Commission approves a 1.5-year depreciation-life extension of Blue Lake Peaking Plant Units 1–4, but no tracking of this decrease in depreciation expense.

5. The Commission authorizes the depreciation lives of Maplewood and Sibley Propane Air peaking plants to be extended by 12 years, from the current retirement date of December 2029.

6. The Commission withholds any decision on the Sherco 3 and King depreciation lives until the issue is addressed in docket E-002, E-015, E-017/CI-23-375 examining ratemaking treatment for early retired coal plants.

7. The Commission approves the depreciation lives, salvage rates, and accrual rates presented in the Xcel's response to Department Information Request No. 37, estimated to result in an increase in depreciation expense of $12,711,918.

8. The Commission approves Xcel's establishment of a new sub-account for FERC account 303, related to gas software assets, with a 7-year depreciable lives, 0% net salvage, and 14.29% depreciation rate.

9. The Commission approves Xcel's establishment of a new sub-account for FERC account 303, related to gas software assets, with a 15-year depreciable lives, 0% net salvage, and 6.67% depreciation rate.

10. The Commission defers approval of Xcel's proposal of a new 10-year Energy Storage account, FERC account 351, 0% net salvage, and 10% depreciation rate until such a time when assets have been purchased and an appropriate net salvage can be determined.

11. The Commission approves Xcel's proposal of a new Electric Utility Segment account, FERC account 359, for Roads and Trails, 60-year average service lives, 0% net salvage, and 1.67% depreciation rate.

12. The Commission defers approval of Xcel's proposal of a Distribution 10-year Energy Storage account, FERC account 363, 0% net salvage, and 10% depreciation rate until such a time when assets are purchased.

13. The Commission denies Xcel's proposal to defer any changes resulting from the results of the Five-Year Study to a future rate case and requires Xcel to implement the changes to depreciation rates effective January 1, 2023.

14. The Commission requires Xcel to include Schedule K – Accumulated Depreciation Linkage between Schedules in all future Five-Year filings.

15. Xcel shall include a complete Cost-of-Removal Study in its next Five-Year filing.

16. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Will Seuffert
Executive Secretary

CERTIFICATE OF SERVICE

I, Mai Choua Xiong, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
ORDER APPROVING PETITION WITH MODIFICATIONS AND SETTING ADDITIONAL FILING REQUIREMENTS

Docket Number **E,G-002/D-22-299**
Dated this 9th day of January, 2024

/s/ Mai Choua Xiong

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_22-299_D-22-299
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_22-299_D-22-299
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-299_D-22-299
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_22-299_D-22-299
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_22-299_D-22-299
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_22-299_D-22-299
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_22-299_D-22-299
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_22-299_D-22-299
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_22-299_D-22-299
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_22-299_D-22-299
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_22-299_D-22-299
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_22-299_D-22-299
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_22-299_D-22-299
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_22-299_D-22-299
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 E 7th St St Paul, MN 55106	Electronic Service	No	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_22-299_D-22-299
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_22-299_D-22-299
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_22-299_D-22-299
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_22-299_D-22-299
Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	OFF_SL_22-299_D-22-299
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_22-299_D-22-299
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_22-299_D-22-299
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_22-299_D-22-299
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

September 8, 2022

Will Seuffert **—Via Electronic Filing—**
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION 2022 ANNUAL REVIEW OF REMAINING LIVES AND DEPRECIATION RATES FOR ELECTRIC AND GAS PRODUCTION AND GAS STORAGE FACILITIES
DOCKET NO. E,G002/D-22-299

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed annual update of remaining lives and depreciation rates for its electric and natural gas production facilities in accordance with the Commission's September 8, 1978 Order in Docket No. E002/D-77-1086A, November 13, 2015 Order in Docket No. E,G002/D-15-46, September 4, 2018 Order in Docket No. E,G002/D-18-162, October 22, 2019 order in Docket No. E,G002/D-19-161, September 2, 2021 Order in Docket No. E,G002/M-19-723, Minn. Stat. § 216B.11, and Minnesota Rules 7825.0500 through 7825.0900.

As noted in our extension request filings submitted in this docket, the Company intended to file a Petition that contained: 1) the Company's 2022 Electric and Gas Production and Gas Storage Facilities Annual Review of Remaining Lives (ARL); 2) the 2022 Transmission, Distribution, and General Accounts (TDG) ARL; and 3) and the Five-Year TDG Depreciation Study. The Company's first extension request asked to file the complete filing by October 31, 2022. After filing the first extension request, it was brought to our attention that the extension would not allow parties enough time to review the 2022 Filing and consider the results for inclusion in our pending Multi-Year Electric Rate Case (MYRP) – Docket No. E002/GR-21-630. We then requested an extension to no later than September 12, 2022, to better align with the timing of the electric rate case. The Commission approved the Company's first extension request to October 31, 2022 in their July

20, 2022 Order, and no Commission action was taken on the Company's second extension request.

Today we provide the 2022 Electric and Gas Production and Gas Storage Facilities ARL so the results can be incorporated into our pending MYRP. We also intend to file the 2022 TDG ARL portion of the filing on Monday, September 12, 2022. However, the Five-Year Depreciation Study being completed by Alliance Consulting Group is still underway and will not be filed with the TDG ARL portion on Monday. This portion of the filing will instead be filed by the October 31, 2022 Ordered date.

The enclosed Petition is marked "Not-Public" as it contains information the Company considers to be security information as defined by Minn. Stat. §13.37(1)(a). This information could be used to damage our electricity generation and transmission facilities and could jeopardize the security of individuals and property. The Company thus protects it as security information.

We have electronically filed this document with the Minnesota Public Utilities Commission, and summaries have been served on the parties on the attached service lists. Please contact me at laurie.j.wold@xcelenergy.com or (612) 330-5510 if you have any questions regarding this filing.

Sincerely,

/s/

LAURIE J. WOLD
SENIOR MANAGER, CAPITAL ASSET ACCOUNTING

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2022 ELECTRIC AND GAS PRODUCTION AND GAS STORAGE FACILITIES ANNUAL REVIEW OF REMAINING LIVES

DOCKET NO. E,G002/D-22-299

PETITION

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition for approval of our 2022 Review of Remaining Lives. After performing our annual review of electric and gas production and gas storage asset lives and net salvage rates, we respectfully request approval of the following:

- Passage of time adjustments for all electric and natural gas production and gas storage facilities, except as discussed below;
- Modification to the remaining lives for electric production plants: Allen S. King, Sherburne County (Sherco) Unit 3, Blue Lake 1-4, Grand Meadow (Ben Fowke Wind Energy Center) and Nobles Wind farms;
- Initial remaining life and net salvage rate for Northern Wind and Rock Aetna wind facilities; Modification to the remaining lives for gas plants: Maplewood and Sibley Gas Production and the Wescott Gas Storage facility.

Attachment A is a summary of the requested 2023 remaining lives and net salvage rates.

Additionally, in compliance with past practice and the Commission's Order in our 2020 remaining life filing[1], we provide a discussion of the following items for the Commission's information:

- An explanation and schedule of the differences between depreciation remaining lives and the Integrated Resource Plan[2] (IRP) lives of electric production plants.
- An update on removal costs for Black Dog Units 3 and 4, Minnesota Valley, Key City, and Granite City.
- A supplemental schedule including: actual costs to date, projected future costs and percentage of completion-to-date for Minnesota Valley Plant, Granite City Plant, and Black Dog Units 3-4, as applicable.

Overall, this Petition reflects a net increase in total Company depreciation and amortization expense of $48.0 million for existing assets and proposes eight remaining lives adjustments with no change to net salvage percentages. As presented in Attachment B Comparison of Present and Proposed Lives, $24.3 million of depreciation expense reduction is adjusted due to approval of repowering the Grand Meadow and Nobles wind farms and related remaining life extensions along with proposed remaining life extensions at the Maplewood, Sibley and Wescott gas peaking facilities. This depreciation expense reduction is adjusted to reflect the $24.3 million reduction that is currently being reflected in interim rates. Consistent with our 2020 Remaining Life Petition which included the most recent 5-year dismantling study (Docket No. E,G002/D-19-723), we respectfully request Commission approval of this same study to be effective January 1, 2023, as this remains the most recent dismantling study.

SUMMARY OF FILING

A one-paragraph summary of the filing accompanies this Petition pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216B.17, subd.3, we have electronically filed this Petition. A Summary of the filing has been provided to all persons on the attached service list.

[1] Docket No. E,G002/M-19-723, September 2, 2021 Order.
[2] Docket No. E002/RP-19-368

III. GENERAL FILING INFORMATION

Pursuant to Minnesota Rules 7825.3200, 7825.3500, and 7829.1300, subp. 3. Xcel Energy provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Matt B. Harris
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 330-7641

C. Date of Filing and Date Proposed Rates Will Take Effect

The date of the filing is September 8, 2022. The Company requests that the Commission approve our proposed remaining lives and net salvage rates effective January 1, 2023.

D. Statute Controlling Schedule for Processing the Filing

Under Minn. R. 7829.0100, subp. 11, this request for approval of remaining lives is a "miscellaneous" filing because no determination of Xcel Energy's general revenue requirements is necessary. Comments on a miscellaneous filing are due within 30 days of filing, with replies due 10 days thereafter.

E. Utility Employee Responsible for the Filing

Laurie J. Wold
Senior Manager, Capital Asset Accounting
Xcel Energy
414 Nicollet Mall, 401 – 3rd Floor
Minneapolis, MN 55401
(612) 330-5510

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, subp. 2, the Company requests that the following persons be placed on the Commission's official service list for this matter:

Matt B. Harris
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, Minnesota 55401
Matt.B.Harris@xcelenergy.com

Christine Schwartz
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, Minnesota 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Regulatory Records.

V. REVIEW OF REMAINING LIVES AND NET SALVAGE RATES

A. Background

The Commission approved our current remaining lives and net salvage rates effective January 1, 2021, in their September 2, 2021 Order in Docket No. E,G002/D-19-723. This 2022 review uses the previously approved remaining lives and net salvage rates—assuming a two-year passage of time adjustment—as the starting point for this filing. Thus, we have reviewed the remaining lives of our electric and natural gas production and gas storage facilities as of January 1, 2023, considering system demand, availability of fuel supplies, operating and maintenance costs, and future technological advancements that influence the decision about retiring electric and natural gas facilities.

In this filing we request approval of the following changes effective January 1, 2023:

- Passage of time adjustments for all electric and natural gas production and gas storage facilities, except as discussed below;
- Modification to the remaining lives for electric production plants: Allen S. King, Sherburne County (Sherco) Unit 3, Blue Lake 1-4, Grand Meadow (Ben Fowke Wind Energy Center) and Nobles Wind farms;
- Modification to the remaining lives for gas plants: Maplewood and Sibley Gas Production and the Wescott Gas Storage facility.

B. Passage of Time Adjustment

As mentioned above, to begin our analysis of remaining lives, we incorporated a two-year passage of time adjustment to the 2021 certified remaining lives of all facilities. Subtracting two years from the present certified remaining life results in the proposed remaining lives as of January 1, 2023. The passage of time adjustment does not change the annual depreciation accrual, but simply reflects that Xcel Energy production facilities will have aged two years since January 1, 2021.

Attachment B shows our Comparison of Present and Proposed Lives, as it relates to 2023 estimated depreciation expense.

Pursuant to Minn. R. 7825.0700, subp. 1, we provide with this filing, the following attachments for our electric and gas assets:

- Attachment C – 2021 Plant In-service;
- Attachment D – 2021 Analysis of Depreciation Reserve; and
- Attachment E – 2021 Summary of Annual Depreciation Accruals.

C. Recommended Changes to Remaining Lives for Production Facilities

As discussed below, we are requesting approval for changes to the remaining lives of eight facilities which results in a net increase in total Company depreciation and amortization expense of approximately $48.0 million for existing assets. This is the impact of changing lives for assets that are not included in interim rates of the Company's currently filed gas and electric rate cases. The change to Steam Regulatory Liability Amortization of $251,565, is not presented in the table below.

Table 1: Summary of Production Remaining Lives Changes

Function	Plant	Plant Balance	Reserve Balance	Present Depreciation Expense	Proposed Depreciation Expense	Proposed Less: Present Expense
Steam	Allen S. King	714,881,790	389,750,340	26,958,660	65,150,096	38,191,435
Steam	Sherco Unit 3	795,522,130	581,518,269	23,070,842	34,606,264	11,535,421
Other	Blue Lake Units 1 thru 4	26,312,577	33,213,307	2,301,836	383,639	(1,918,197)
Other *	Grand Meadow Wind	212,239,365	126,770,497	10,152,728	5,294,963	(4,857,764)
Other *	Nobles Wind	518,999,319	263,019,551	23,237,558	13,090,153	(10,147,405)
Gas Prod *	Maplewood	5,893,057	7,604,422	493,835	181,939	(311,896)
Gas Prod *	Sibley	13,873,380	10,855,388	1,245,707	458,945	(786,763)
Gas Storage *	Wescott	70,160,786	60,697,591	9,548,248	1,221,827	(8,326,421)
		2,357,882,403	1,473,429,364	97,009,415	120,387,826	23,378,411

** included in interim rates*

1. *Electric Utility – Steam Production – Allen S. King and Steam Sherco Unit 3*

The MPUC recently approved 2020-2034 Upper Midwest Integrated Resource Plan (Docket No. E002/RP-19-368), in which the Company charts the path towards achieving some of the most ambitious carbon reduction goals of any utility in the U.S. Specifically – we aim to reduce carbon emissions 80 percent by 2030 and provide 100 percent carbon-free energy by 2050. One of the building blocks necessary to achieve this goal is the elimination of coal-fired generation from the NSP system by 2030.

In a step towards achieving these goals, the Company proposes, in this proceeding, new remaining lives due to the approved accelerated retirements of the Steam Allen S. King and Steam Sherco Unit 3 plant from June 2037 to December of 2028 and December of 2034 to December of 2030 respectively.

Table 2: Steam Proposed Retirement Date Changes

Account	Proposed Retirement date	Current Retirement date
Allen S. King		
E311	Dec-28	Jun-37
E312	Dec-28	Jun-37
E314	Dec-28	Jun-37
E315	Dec-28	Jun-37
E316	Dec-28	Jun-37
Sherco Unit 3		
E311	Dec-30	Dec-34
E312	Dec-30	Dec-34
E314	Dec-30	Dec-34
E315	Dec-30	Dec-34
E316	Dec-30	Dec-34

The Allen S. King Plant is located on the west shore of Lake St. Croix in the City of Oak Park Heights, just south of Stillwater, Minnesota, Allen S. King is a single-unit coal-fired generating plant with a cyclone boiler. The unit provides base load electric service with power production capability of 529 megawatts (MW) and it has been in service since 1968. The plant was retrofit with pollution-control equipment and increased power output in 2007 as part of the Metropolitan Emissions Reduction Program (MERP). The retirement date was set as 30 years from this 2007 rehabilitation.

The Sherco plant is a three-unit coal-fired base load plant located in Becker, Minnesota. Units 1 and 2 began operation in 1976 and 1977, respectively, generating a net 700 MW each. Unit 3 began operation in 1987 generating a net 855 MW and is jointly-owned with Southern Minnesota Municipal Power Association.

The impacts resulting from the adjustments to the Allen S. King and Sherco Unit 3 are shown in Attachment B, Comparison of Present and Proposed Lives.

2. *Electric Utility – Other Production: Grand Meadow (Ben Fowke Wind Energy Center) and Nobles Wind Farms*

To support economic relief and recovery in Minnesota in the wake of the COVID-19 pandemic, supporting job creation while also achieving cost savings for customers, the Company received approval, in a January 22, 2021 Order in Docket No. E-002/M-20-

620, to repower four currently existing wind facilities – Border, Grand Meadow, Nobles, and Pleasant Valley. The Company proposes to formalize the remaining life extensions and their associated retirement dates for the Grand Meadows and Nobles wind farms in this proceeding. We propose the new retirement end-of-life date become effective upon the in-service date of the repowering. The Border and Pleasant Valley wind farms extensions are beyond the scope of this filing, due to the effective date of this filing January 1, 2023. Those wind farms will be addressed in a future Remaining Life filing.

Table 3: Wind Proposed Retirement Date Changes

Account	Proposed Retirement date	Current Retirement date
Grand Meadow Wind		
E340.1	Nov-43	Nov-33
E341	Nov-43	Nov-33
E342	Nov-43	Nov-33
E343	Nov-43	Nov-33
E344	Nov-43	Nov-33
E345	Nov-43	Nov-33
E346	Nov-43	Nov-33
Nobles Wind		
E340.1	Nov-45	Nov-35
E341	Nov-45	Nov-35
E342	Nov-45	Nov-35
E343	Nov-45	Nov-35
E344	Nov-45	Nov-35
E345	Nov-45	Nov-35
E346	Nov-45	Nov-35

The Grand Meadow Wind Farm is an approximately 100 MW large energy facility comprised of 67 General Electric 1.5 MW wind turbines mounted on freestanding 262.5 feet high tubular steel towers supported by cast-in-place concrete foundations. The rotor diameter is 252.6 feet, resulting in an overall height of 388.8 feet when one blade is in the vertical position. The equipment at each tower also includes pad mount transformers. The investment in-service date was November 15, 2008 based on the commissioned turbines.

The Nobles Wind Farm is a 201 MW wind production farm comprised of 134 wind turbines. The wind turbines at the Nobles Wind Farm are identical to the turbines in use at Grand Meadow Wind Farm. The investment in-service date was December 21, 2010.

The impacts resulting from the adjustments to the Grand Meadow and Nobles wind farms are shown in Attachment B, Comparison of Present and Proposed Lives. In the Attachment B calculation of total change to depreciation and amortization expense, the Company removed the impact of reduced depreciation expense related to Grand Meadows and Noble life extensions, because that reduction in depreciation expense is currently reflected in interim rates and included in the currently active NSP Minnesota electric rate case (Docket No. E002-GR-21-630).

3. Electric Utility – Other Production Blue Lake 1-4:

We are proposing to extend the life of Blue Lake 1-4, in this proceeding, from the currently approved retirement date of June 2023 to December of 2025. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

Table 4: Other Proposed Retirement Date Changes

Account	Proposed Retirement date	Current Retirement date
Blue Lake Units 1 thru 4		
E341	May-45	May-45
E342	Dec-25	Jun-23
E343	Dec-25	Jun-23
E344	Dec-25	Jun-23
E345	Dec-25	Jun-23
E346	Dec-25	Jun-23

The Blue Lake Peaking Plant is located south of Shakopee, Minnesota, and consists of four 55 MW oil-fired combustion turbines. The plant became operational in 1974. The plant is primarily used for capacity accreditation, and lesser so for energy production during peak demand periods. The impacts resulting from the adjustments to the Other Blue Lake 1-4 is shown in Attachment B, Comparison of Present and Proposed Lives.

4. Electric Utility – Other Production: Northern Wind and Rock Aetna

Since the June 15, 2021, Order approving the Company's acquisition of the 120 MW Northern Wind and Rock Aetna projects in Docket No. E002/M-20-620, the Company plans to in-service two new wind projects in 2022 and 2023 respectively – Below are details on each plant:

- Northern Wind is an 97.5 MW wind project, located southwest Minnesota, is a Build, Own, Transfer (BOT) project between Xcel and ALLETE with an estimated acquisition date of December 2022, with a proposed RL of 25.0 years. Crowned Ridge wind farm, located in Codington County in northeastern South Dakota, is a 200 MW project estimated to be in-serviced in November 2020.
- Rock Aetna Wind is 20 MW wind project, located in southwest Minnesota, with and estimated acquisition date of January 2023, with a proposed RL of 25.0 years.

Consistent with the previous 2020 Remaining Life Filing, the Company proposes the initial life for these two wind farms be set to 25 years from their in-service dates and have a -10.5 net salvage percentage.

5. Gas Utility – Gas Production-Maplewood and Sibley

The Sibley Propane Air peaking plant is located in Mendota Heights, and the Maplewood Propane Air peaking plant is located in Maplewood. These plants are used to ensure we can meet our firm customers' demand for natural gas as we approach Design Day conditions and to assist in intra-day balancing. Although such conditions do not regularly occur, the peaking plants are important to design day plans. Because these plants generally are available to provide gas to firm customers during peak conditions, the Company can avoid incremental pipeline capacity purchases to meet the same need. The peaking plants provide diversity to the Company's capacity portfolio in addition to third-party interstate pipeline capacity. Propane is delivered in its liquid state via truck to the Sibley and Maplewood plants and is stored at the plants until needed during the heating season. When dispatched during winter months, the Company vaporizes the propane by heating it, mixing it with air and injects the gas into the distribution system, where it is blended with natural gas and ultimately delivered to customers. Like Wescott, the Sibley and Maplewood peaking plants are primarily used to support gas supply requirements during peak demand conditions.

The Company is proposing life extensions for Maplewood and Sibley due to recent capital investments in the facilities driven by an investigation consisting of a comprehensive Hazard and Operability and Layer of Protection Analysis (Hazop Study). The purpose of this, was to "review the design in order to find design, operability, and engineering issues that may otherwise not have been found" and identify potential resolutions. In short, it is a comprehensive review of all the components of the plant to complete a thorough assessment of risks and mitigations. This study determined that additional investments needed to be made at Sibley and Maplewood before we can safely operate them, as the vaporization systems at both plants were at the end of their life expectancy. As such, the Company dedicated significant capital expenditures over approximately three years (2021-2023), with the first objective being a return to vaporization at all plants under safe operating conditions for the upcoming winters. The investments at the plants will extend their operational life expectancy, enabling them to serve customers beyond their current lives.

Table 5: Gas Production Proposed Retirement Date Changes

Account	Proposed Retirement date	Current Retirement date
Maplewood		
G305	Dec-41	Dec-29
G311	Dec-41	Dec-29
G320	Dec-41	Dec-29
Sibley		
G305	Dec-41	Dec-29
G311	Dec-41	Dec-29
G320	Dec-41	Dec-29

The impacts resulting from the adjustments to the Maplewood and Sibley Gas Production 1-4 are shown in Attachment B, Comparison of Present and Proposed Lives. In the Attachment B calculation of total change to depreciation and amortization expense, the Company removed the impact of reduced depreciation expense related to Maplewood and Sibley due to proposed life extensions, because that reduction in depreciation expense is currently reflected in interim rates and included in the currently active NSP Minnesota gas rate case (Docket No. G002-GR-21-678). The Company requests that the proposed change in Remaining Life and depreciation impact, for Maplewood and Sibley peaking plants be effective, January of 2022, which aligns with NSPM gas customers interim rates.

6. *Gas Utility – Gas Storage: Wescott*

The Wescott Liquified Natural Gas (LNG) Plant was placed in-service in 1972. The plant cools, then stores the LNG in large storage tanks. Vaporizing equipment is used later to warm and convert the liquefied methane back to a gas for use in the distribution system.

The cold box, which is a critical piece of equipment in the liquefaction process, failed in 2019 and was replaced in 2020. With the addition of new equipment at the facility, we believed it was important to evaluate the rest of the lives for the Wescott Gas Storage facility. The LNG facilities at the Wescott plant remain an important part of gas operations for the Company, especially during extreme cold weather conditions.

At this time, Company personnel believe we would be able to operate the LNG facilities for a minimum of another 10 years. While there are no major capital additions planned for the next year, the Company plans to maintain the facility and complete capital upgrades when needed, such as the replacement of the cold box in 2020. The LNG storage tanks at Wescott were in-serviced in 1972 and 1975.

Designers/suppliers of LNG storage vessels typically offer a "design life" of anywhere from 25 to 40 years from in-service date. After this date, however, it does not mean they are no longer useful. When properly maintained, LNG tanks may last years, even decades, beyond their original design life as evidenced by the number of in-service LNG tanks in the United States to date. Very few have been decommissioned since their original construction in the 1960s and 1970s, and very few have been found to have deficiencies significant enough to adversely impact their longevity.

The Wescott LNG facility is an important part of the Xcel Energy system. In order to meet our capacity demands on the coldest days of the year, Wescott provides about 17% of necessary supply. Without this source, Xcel Energy would have to utilize more expensive options such as a pipeline.

For these reasons, we are recommending that the remaining lives of the Wescott accounts be extended as shown in Table 6 below.

Table 6: Gas Storage Proposed Retirement Date Changes

Account	Proposed Retirement date	Current Retirement date
Wescott		
G361	Dec-41	Dec-23
G362	Dec-41	Dec-23
G363	Dec-41	Dec-23
G363.1	Dec-41	Dec-23
G363.2	Dec-41	Dec-27
G363.3	Dec-41	Dec-32
G363.4	Dec-41	Dec-23
G363.5	Dec-41	Dec-23

The impact resulting from the adjustments to the Wescott Liquified Gas Plant is shown in Attachment B, Comparison of Present and Proposed Lives. In the Attachment B calculation of total change to depreciation and amortization expense, the Company removed the impact of reduced depreciation expense related to Wescott due to proposed life extensions, because that reduction in depreciation expense is currently reflected in interim rates and included in the currently active NSP Minnesota gas rate case (Docket No. G002/GR-21-678). The Company requests that the proposed change in Remaining Life and depreciation impact, for the Wescott peaking facility be effective January of 2022, which aligns with NSPM gas customers interim rates.

D. Change in Net Salvage Rates

The Commission's September 2, 2021 order in Docket No. E,G002/D-19-723 requires the Company to submit, " an historical comparison in remaining lives and net salvage rates;." The Company satisfies this requirement through use of the previously completed analysis of the cost of removal and net salvage for its electric and gas facilities and proposes no change to the current net salvage rates.

We provide a Comparison of Present and Proposed Lives as Attachment B to this filing, summarizing the depreciation expense impact of the proposed change to net salvage rates in combination with the proposed changes to remaining lives. Furthermore, to be consistent, we are providing Attachment I, which is a comparison of Present and Proposed Net Salvage Rates. This attachment shows the calculation of proposed net salvage rates and compares them to the previously approved net salvage rates.

1. *Completion of the study and net salvage calculations*

In 2019, the Company contracted with TLG Services, Inc. (TLG) to perform a comprehensive dismantling study on all steam, hydro, and other production electric generating plants as well as gas production and storage facilities. We provide as Attachment J to this filing, the 2020 TLG Dismantling Study (Dismantling Study), which is the same dismantling study that was submitted and approved in the Company's previous Remaining Life filing Docket No. E,G002-D-19-723. The Company is not proposing a change to net salvage rates in this proceeding. The main purpose of the filed Dismantling Study was to estimate the present-day costs for retiring and demolition of the facilities, also known as final removals of existing facilities. We provide with the Dismantling Study a complete list of the assumptions used in the cost estimates.

E. Removal Update

Order Point 8 of the Commission's September 2, 2021 Order to the 2020 Remaining Lives filing, required the Company to continue to provide "updates on removal costs for the Minnesota Valley Plant, Key City Plant, Granite City Plant, and Black Dog Units 3 & 4, including the impact on depreciation reserves, and a final true-up when the retirement/removal is completed." We provide the requested information below.

Order Point 8 required, "In its next depreciation filing, the Company shall provide a supplemental schedule with the (1) actual costs to date, (2) projected future costs, and (3) percentage of completion to date for the Minnesota Valley Plant, Key City Plant, Granite City Plant, and Black Dog Units 3 & 4, as applicable." This information is provided for Black Dog and Minnesota Valley in Attachment H. As discussed in further detail below, the Company will provide updates for Black Dog Units 3 & 4, Minnesota Valley, Key City, and Granite City.

1. *Electric Utility –Steam Production: Black Dog Units 3 and 4*

Black Dog Units 3 and 4 were officially retired from service in April 2015. These were coal-burning, steam production units. Their removal from service ends the coal-fired production of electricity at Black Dog after more than 60 years.

As of today, the Unit 4 turbine, generator, and boiler have been removed. The ash ponds have been dredged, filled, and covered. The original coal stacks for Units 2 and 3 and the tall common stack have been removed and the coal yard remediation has been completed. The Unit 3 turbine, the boiler for Units 2 and 3, and related plant equipment are planned for removal in future years. There is also a portion of the facility that is necessary for the continued operation of Units 5 and 6. It is anticipated that these shared portions of the generating facility will not be removed until the cessation of all Black Dog location operations. Site monitoring and clean-up continues as the Company waits for letter and final approval.

The Company believes Black Dog Unit 3 & Unit 4 removal process and current dismantling scope of work will be completed by the end of 2022. Trailing charges may occur in 2023, and if so, are expected to be immaterial. An update to actual and forecast costs, along with an estimated completion percentage status is provided in Schedule H.

2. *Electric Utility –Steam Production: Minnesota Valley*

The Minnesota Valley Plant is a former steam production facility located in Granite Falls, Minnesota along the Minnesota River. Minnesota Valley last burned coal in 2004, and the air permit was formally retired in 2009. The plant is no longer in operation.

The removal and remediation of the coal yard was completed in 2019. Asbestos abatement was completed in 2021, with the full site demolition date to be completed near the end of 2022; possibly in the spring of 2023 depending on weather conditions. Removal costs are currently occurring in 2022, with the expectation they will cease by year end. An update to actual and forecast costs, along with an estimated completion percentage status is provided in Schedule H.

3. Electric Utility – Other Production: Key City and Granite City

The Key City Peaking Plant is located in Mankato, Minnesota, adjacent to Xcel Energy's Wilmarth Power Plant. The Key City plant had four units that generated a total of 64 MW of electricity using natural gas and oil as fuel. The plant became operational in 1970 and reached its end of life at the end of 2012.

The Granite City Peaking Plant is located in St. Cloud, Minnesota, and was built in 1969 and operationally retired in mid-2019. The plant consisted of four units that generated a total of 61 MW of electricity using natural gas and oil.

Demolition at Key City and Granite City plants was completed in fall of 2021. There is one remaining administrative item for Granite City, which is an environmental closure letter which the Company expects to receive soon. A few charges carried over into 2022 at these plants, however, for all intents and purposes, both projects are complete.

4 Electric Utility – Plant Retirements and Removal Summary

It is the Company's expectation that the proposed dismantling of the Key City, Granite City, Minnesota Valley and Black Dog Unit 3 and Unit 4 production plants, will have been fully completed, by the next Remaining Life filing. The Company proposes at that time to complete a full review of Cost of Removal (COR) reserve balances, particularly the production plants that have been fully dismantled, and have a final determination of reserve amounts to reallocate, within the functional class. Additionally, there are concurrent and future regulatory proceedings, that the MPUC will adjudicate, that may impact future proposed reserve reallocations. At this time, it appears there is a net excess COR reserve balance, for the dismantled plants, but the Company proposes to contemplate that in the next Remaining Life filing due to pending rulings and other factors mentioned above.

F. Resource Plan Comparison

Consistent with past practice, we provide an IRP Comparison for our electric production plant facilities that identifies, and provides a rationale for, differences between our proposed depreciation lives and the planning lives used in the IRP Reference Plan as Attachment F.

The IRP is currently pending before the Commission. After that docket is settled, any agreed upon changes to plant lives will be reflected in the annual remaining life docket following IRP acceptance.

VI. MINNESOTA JURISDICTIONAL DEPRECIATION

For *regulatory* purposes, the depreciation expense and the accumulated provision for depreciation are based solely on the remaining lives and net salvage rates approved by the respective Public Utility Commissions. For *financial* purposes, we must account for the impact of those differences in our approved rates in Company retail jurisdictions. We do this by calculating a depreciation expense for each jurisdiction based on its remaining lives, then apply a jurisdictional allocator to each resulting amount and add the amounts together to get a total Company financial view. The Attachments to this filing show the reserve amounts applicable to the Minnesota jurisdiction, shown at a total Company level. This method has been in use for the Minnesota assets since 2009 and has been filed in the last four electric rate case proceedings.

However, the depreciation reserve using Minnesota-approved lives and net salvage rates in this filing cannot be compared directly with total Company financial results reported in Securities and Exchange Commission or other financial filings. This stems from the fact that the North Dakota Public Service Commission and the South Dakota Public Utilities Commission have applied remaining lives for some production plants that are materially different from what the Minnesota Commission has approved in previous remaining life filings.[3]

VII. EFFECT OF THE CHANGE IN RATES

This Petition will not impact customer interim rates, the price of Xcel Energy natural gas and electric service, or the terms and conditions of service. Rather, the changes will reflect the way the Company recognizes depreciation expenses for relevant assets in the current year.

[3] 2020 North Dakota Electric Rate Case, Case No. PU-20-441; 2014 South Dakota Electric Rate Case, Docket No. EL14-058.

CONCLUSION

Xcel Energy respectfully requests the Commission approve a total increase in depreciation and amortization expense of $48.0 million for existing assets as proposed in this filing based on the proposed remaining lives and net salvage rates for the electric and gas utilities, with an effective date of January 1, 2023 for assets included in base rates, and effective with the in-service date for assets included in Riders. Additionally, as discussed above, that the Remaining Life changes and depreciation impacts related to Maplewood, Sibley and Wescott be effective January 1, 2022, to be consistent with NSPM gas customer current interim rates.

Dated: September 8, 2022

Northern States Power Company

2022 REVIEW OF REMAINING LIVES
Supporting Attachments

A	Summary of Proposed Remaining Lives
B	Comparison of Present and Proposed Lives
C	2021 Plant In-service Rollforward
D	2021 Accumulated Depreciation Rollforward
E	2021Summary of Annual Depreciation Accruals
F	Integrated Resource Plan Comparison
G	Historical Comparison of Changes to Remaining Life
H	Removal Costs by Year (formerly Pending Docket)
I	Comparison of Present and Proposed Net Salvage Rates
J	2020 5-year Dismantling Cost Study
K	Total Life of Plants

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2022 ELECTRIC AND GAS PRODUCTION AND GAS STORAGE FACILITIES ANNUAL REVIEW OF REMAINING LIVES

DOCKET NO. E,G002/D-22-299

PETITION

SUMMARY OF FILING

Please take notice that on September 8, 2022, Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission a Petition for approval of its 2022 Review of Remaining Lives. The Company requests an increase of approximately $38.6 million in 2023 total Company annual depreciation and amortization expense for existing assets increase for electric utility generating facilities and gas utility generation and storage facilities based on beginning of year balances for assets not presently included in rate riders. The Company requests that upon Commission approval, the new remaining lives become effective January 1, 2023 for assets included in base rates, and effective with the in-service date for assets included in Riders.

Electric Utility
Steam Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Allen S. King					
E311	Structures & Improvements	-9.2	6.0	years	Dec-28
E312	Boiler Plant Equipment	-9.2	6.0	years	Dec-28
E314	Turbogenerator Units	-9.2	6.0	years	Dec-28
E315	Accessory Electric Equipment	-9.2	6.0	years	Dec-28
E316	Miscellaneous Power Plant Equipment	-9.2	6.0	years	Dec-28
Red Wing					
E311	Structures & Improvements	-23.5	5.0	years	Dec-27
E312	Boiler Plant Equipment	-23.5	5.0	years	Dec-27
E314	Turbogenerator Units	-23.5	5.0	years	Dec-27
E315	Accessory Electric Equipment	-23.5	5.0	years	Dec-27
E316	Miscellaneous Power Plant Equipment	-23.5	5.0	years	Dec-27
Sherco Unit 1					
E311	Structures & Improvements	-15.1	3.0	years	Dec-25
E312	Boiler Plant Equipment	-15.1	3.0	years	Dec-25
E314	Turbogenerator Units	-15.1	3.0	years	Dec-25
E315	Accessory Electric Equipment	-15.1	3.0	years	Dec-25
E316	Miscellaneous Power Plant Equipment	-15.1	3.0	years	Dec-25
Sherco Unit 2					
E311	Structures & Improvements	-15.1	3.0	years	Dec-25
E312	Boiler Plant Equipment	-15.1	0.0	years	Dec-22
E314	Turbogenerator Units	-15.1	0.0	years	Dec-22
E315	Accessory Electric Equipment	-15.1	0.0	years	Dec-22
E316	Miscellaneous Power Plant Equipment	-15.1	0.0	years	Dec-22
Sherco Unit 3					
E311	Structures & Improvements	-7.9	8.0	years	Dec-30
E312	Boiler Plant Equipment	-7.9	8.0	years	Dec-30
E314	Turbogenerator Units	-7.9	8.0	years	Dec-30
E315	Accessory Electric Equipment	-7.9	8.0	years	Dec-30
E316	Miscellaneous Power Plant Equipment	-7.9	8.0	years	Dec-30
Wilmarth					
E311	Structures & Improvements	-25.8	5.0	years	Dec-27
E312	Boiler Plant Equipment	-25.8	5.0	years	Dec-27
E314	Turbogenerator Units	-25.8	5.0	years	Dec-27
E315	Accessory Electric Equipment	-25.8	5.0	years	Dec-27
E316	Miscellaneous Power Plant Equipment	-25.8	5.0	years	Dec-27

Electric Utility
Nuclear Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Monticello					
E302	Franchises & Consents	0.0	7.8	years	Sep-30
E321	Structures & Improvements	0.0	7.8	years	Sep-30
E322	Reactor Plant Equipment	0.0	7.8	years	Sep-30
E323	Turbogenerator Units	0.0	7.8	years	Sep-30
E324	Accessory Electric Equipment	0.0	7.8	years	Sep-30
E325	Miscellaneous Power Plant Equipment	0.0	7.8	years	Sep-30
Monticello - Interim Storage Facility					
E321	Structures & Improvements	0.0	7.8	years	Sep-30
E322	Reactor Plant Equipment	0.0	7.8	years	Sep-30
Prairie Island Unit 1 & 2					
E302	Franchises & Consents	0.0	11.3	years	Apr-34
E321	Structures & Improvements	0.0	11.3	years	Apr-34
E322	Reactor Plant Equipment	0.0	11.3	years	Apr-34
E323	Turbogenerator Units	0.0	11.3	years	Apr-34
E324	Accessory Electric Equipment	0.0	11.3	years	Apr-34
E325	Miscellaneous Power Plant Equipment	0.0	11.3	years	Apr-34
Prairie Island - Interim Storage Facility					
E321	Structures & Improvements	0.0	11.3	years	Apr-34
E322	Reactor Plant Equipment	0.0	11.3	years	Apr-34

* Note: The Nuclear Decommissioning Accrual is set as an amount rather than a net salvage rate. Please see Schedule 10 for further information.

Electric Utility
Hydro Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Hennepin Island					
E302	Franchises & Consents	0.0	11.2	years	Feb-34
E331	Structures & Improvements	-26.7	11.2	years	Feb-34
E332	Reservoirs, Dams & Waterways	-26.7	11.2	years	Feb-34
E333	Water Wheels, Turbines & Generators	-26.7	11.2	years	Feb-34
E334	Accessory Electric Equipment	-26.7	11.2	years	Feb-34
E335	Miscellaneous Power Plant Equipment	-26.7	11.2	years	Feb-34
St. Croix Falls					
E331	Structures & Improvements	-15.0	5.0	years	Dec-27
E332	Reservoirs, Dams & Waterways	-15.0	5.0	years	Dec-27
Upper Dam					
E332	Reservoirs, Dams & Waterways	-26.7	11.2	years	Feb-34
E335	Miscellaneous Power Plant Equipment	-26.7	11.2	years	Feb-34

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Angus C. Anson Unit 2 & 3					
E341	Structures & Improvements	-6.5	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-11.2	18.0	years	Dec-40
E343	Prime Movers	-11.2	18.0	years	Dec-40
E344	Generators	-11.2	18.0	years	Dec-40
E345	Accessory Electric Equipment	-11.2	18.0	years	Dec-40
E346	Miscellaneous Power Plant Equipment	-11.2	18.0	years	Dec-40
Angus C. Anson Unit 4					
E341	Structures & Improvements	-6.5	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-6.5	22.4	years	May-45
E343	Prime Movers	-6.5	22.4	years	May-45
E344	Generators	-6.5	22.4	years	May-45
E345	Accessory Electric Equipment	-6.5	22.4	years	May-45
E346	Miscellaneous Power Plant Equipment	-6.5	22.4	years	May-45
Black Dog Unit 5					
E341	Structures & Improvements	-10.3	35.3	years	Mar-58
E342	Fuel Holders, Producers & Accessories	-7.2	9.0	years	Dec-31
E343	Prime Movers	-7.2	9.0	years	Dec-31
E344	Generators	-7.2	9.0	years	Dec-31
E345	Accessory Electric Equipment	-7.2	9.0	years	Dec-31
E346	Miscellaneous Power Plant Equipment	-7.2	9.0	years	Dec-31
Black Dog Unit 6					
E341	Structures & Improvements	-10.3	35.3	years	Mar-58
E342	Fuel Holders, Producers & Accessories	-10.3	35.3	years	Mar-58
E343	Prime Movers	-10.3	35.3	years	Mar-58
E344	Generators	-10.3	35.3	years	Mar-58
E345	Accessory Electric Equipment	-10.3	35.3	years	Mar-58
E346	Miscellaneous Power Plant Equipment	-10.3	35.3	years	Mar-58
Blazing Star I Wind					
E340.1	Wind Rights	0.0	22.3	years	Apr-45
E341	Structures & Improvements	-11.6	22.3	years	Apr-45
E342	Fuel Holders, Producers & Accessories	-11.6	22.3	years	Apr-45
E343	Prime Movers	-11.6	22.3	years	Apr-45
E344	Generators	-11.6	22.3	years	Apr-45
E345	Accessory Electric Equipment	-11.6	22.3	years	Apr-45
E346	Miscellaneous Power Plant Equipment	-11.6	22.3	years	Apr-45
Blazing Star II Wind					
E340.1	Wind Rights	0.0	23.1	years	Jan-46
E341	Structures & Improvements	-10.5	23.1	years	Jan-46
E342	Fuel Holders, Producers & Accessories	-10.5	23.1	years	Jan-46
E343	Prime Movers	-10.5	23.1	years	Jan-46
E344	Generators	-10.5	23.1	years	Jan-46
E345	Accessory Electric Equipment	-10.5	23.1	years	Jan-46
E346	Miscellaneous Power Plant Equipment	-10.5	23.1	years	Jan-46

Northern States Power Company
Summary of Proposed Remaining Lives

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment A - Page 3 of 6

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Blue Lake Units 1 thru 4					
E341	Structures & Improvements	-12.7	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-30.6	3.0	years	Dec-25
E343	Prime Movers	-30.6	3.0	years	Dec-25
E344	Generators	-30.6	3.0	years	Dec-25
E345	Accessory Electric Equipment	-30.6	3.0	years	Dec-25
E346	Miscellaneous Power Plant Equipment	-30.6	3.0	years	Dec-25
Blue Lake Units 7 & 8					
E341	Structures & Improvements	-12.7	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-12.7	22.4	years	May-45
E343	Prime Movers	-12.7	22.4	years	May-45
E344	Generators	-12.7	22.4	years	May-45
E345	Accessory Electric Equipment	-12.7	22.4	years	May-45
E346	Miscellaneous Power Plant Equipment	-12.7	22.4	years	May-45
Border Winds					
E340.1	Wind Rights	0.0	18.0	years	Dec-40
E341	Structures & Improvements	-9.5	18.0	years	Dec-40
E342	Fuel Holders, Producers & Accessories	-9.5	18.0	years	Dec-40
E343	Prime Movers	-9.5	18.0	years	Dec-40
E344	Generators	-9.5	18.0	years	Dec-40
E345	Accessory Electric Equipment	-9.5	18.0	years	Dec-40
E346	Miscellaneous Power Plant Equipment	-9.5	18.0	years	Dec-40
Community Wind North					
E340.1	Wind Rights	0.0	23.0	years	Dec-45
E341	Structures & Improvements	-10.5	23.0	years	Dec-45
E342	Fuel Holders, Producers & Accessories	-10.5	23.0	years	Dec-45
E343	Prime Movers	-10.5	23.0	years	Dec-45
E344	Generators	-10.5	23.0	years	Dec-45
E345	Accessory Electric Equipment	-10.5	23.0	years	Dec-45
E346	Miscellaneous Power Plant Equipment	-10.5	23.0	years	Dec-45
Courtenay Wind					
E340.1	Wind Rights	0.0	18.9	years	Nov-41
E341	Structures & Improvements	-10.4	18.9	years	Nov-41
E342	Fuel Holders, Producers & Accessories	-10.4	18.9	years	Nov-41
E343	Prime Movers	-10.4	18.9	years	Nov-41
E344	Generators	-10.4	18.9	years	Nov-41
E345	Accessory Electric Equipment	-10.4	18.9	years	Nov-41
E346	Miscellaneous Power Plant Equipment	-10.4	18.9	years	Nov-41
Crowned Ridge Wind					
E340.1	Wind Rights	0.0	23.0	years	Dec-45
E341	Structures & Improvements	-10.5	23.0	years	Dec-45
E342	Fuel Holders, Producers & Accessories	-10.5	23.0	years	Dec-45
E343	Prime Movers	-10.5	23.0	years	Dec-45
E344	Generators	-10.5	23.0	years	Dec-45
E345	Accessory Electric Equipment	-10.5	23.0	years	Dec-45
E346	Miscellaneous Power Plant Equipment	-10.5	23.0	years	Dec-45
Dakota Range Wind					
E340.1	Wind Rights	0.0	24.1	years	Jan-47
E341	Structures & Improvements	-10.5	24.1	years	Jan-47
E342	Fuel Holders, Producers & Accessories	-10.5	24.1	years	Jan-47
E343	Prime Movers	-10.5	24.1	years	Jan-47
E344	Generators	-10.5	24.1	years	Jan-47
E345	Accessory Electric Equipment	-10.5	24.1	years	Jan-47
E346	Miscellaneous Power Plant Equipment	-10.5	24.1	years	Jan-47
Foxtail Wind					
E340.1	Wind Rights	0.0	22.0	years	Dec-44
E341	Structures & Improvements	-9.1	22.0	years	Dec-44
E342	Fuel Holders, Producers & Accessories	-9.1	22.0	years	Dec-44
E343	Prime Movers	-9.1	22.0	years	Dec-44
E344	Generators	-9.1	22.0	years	Dec-44
E345	Accessory Electric Equipment	-9.1	22.0	years	Dec-44
E346	Miscellaneous Power Plant Equipment	-9.1	22.0	years	Dec-44
Freeborn Wind					
E340.1	Wind Rights	0.0	23.4	years	May-46
E341	Structures & Improvements	-10.5	23.4	years	May-46
E342	Fuel Holders, Producers & Accessories	-10.5	23.4	years	May-46
E343	Prime Movers	-10.5	23.4	years	May-46
E344	Generators	-10.5	23.4	years	May-46
E345	Accessory Electric Equipment	-10.5	23.4	years	May-46
E346	Miscellaneous Power Plant Equipment	-10.5	23.4	years	May-46

Northern States Power Company
Summary of Proposed Remaining Lives

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment A - Page 4 of 6

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Dakota Range Wind					
E340.1	Wind Rights	0.0	24.1	years	Jan-47
E341	Structures & Improvements	-10.5	24.1	years	Jan-47
E342	Fuel Holders, Producers & Accessories	-10.5	24.1	years	Jan-47
E343	Prime Movers	-10.5	24.1	years	Jan-47
E344	Generators	-10.5	24.1	years	Jan-47
E345	Accessory Electric Equipment	-10.5	24.1	years	Jan-47
E346	Miscellaneous Power Plant Equipment	-10.5	24.1	years	Jan-47
Foxtail Wind					
E340.1	Wind Rights	0.0	22.0	years	Dec-44
E341	Structures & Improvements	-9.1	22.0	years	Dec-44
E342	Fuel Holders, Producers & Accessories	-9.1	22.0	years	Dec-44
E343	Prime Movers	-9.1	22.0	years	Dec-44
E344	Generators	-9.1	22.0	years	Dec-44
E345	Accessory Electric Equipment	-9.1	22.0	years	Dec-44
E346	Miscellaneous Power Plant Equipment	-9.1	22.0	years	Dec-44
Freeborn Wind					
E340.1	Wind Rights	0.0	23.4	years	May-46
E341	Structures & Improvements	-10.5	23.4	years	May-46
E342	Fuel Holders, Producers & Accessories	-10.5	23.4	years	May-46
E343	Prime Movers	-10.5	23.4	years	May-46
E344	Generators	-10.5	23.4	years	May-46
E345	Accessory Electric Equipment	-10.5	23.4	years	May-46
E346	Miscellaneous Power Plant Equipment	-10.5	23.4	years	May-46
Grand Meadow Wind					
E340.1	Wind Rights	0.0	20.9	years	Nov-43
E341	Structures & Improvements	-12.5	20.9	years	Nov-43
E342	Fuel Holders, Producers & Accessories	-12.5	20.9	years	Nov-43
E343	Prime Movers	-12.5	20.9	years	Nov-43
E344	Generators	-12.5	20.9	years	Nov-43
E345	Accessory Electric Equipment	-12.5	20.9	years	Nov-43
E346	Miscellaneous Power Plant Equipment	-12.5	20.9	years	Nov-43
High Bridge					
E341	Structures & Improvements	-4.3	25.4	years	May-48
E342	Fuel Holders, Producers & Accessories	-4.3	25.4	years	May-48
E343	Prime Movers	-4.3	25.4	years	May-48
E344	Generators	-4.3	25.4	years	May-48
E345	Accessory Electric Equipment	-4.3	25.4	years	May-48
E346	Miscellaneous Power Plant Equipment	-4.3	25.4	years	May-48
Inver Hills					
E341	Structures & Improvements	-19.4	4.0	years	Dec-26
E342	Fuel Holders, Producers & Accessories	-19.4	4.0	years	Dec-26
E343	Prime Movers	-19.4	4.0	years	Dec-26
E344	Generators	-19.4	4.0	years	Dec-26
E345	Accessory Electric Equipment	-19.4	4.0	years	Dec-26
E346	Miscellaneous Power Plant Equipment	-19.4	4.0	years	Dec-26
Jeffers Wind					
E340.1	Wind Rights	0.0	23.0	years	Dec-45
E341	Structures & Improvements	-10.5	23.0	years	Dec-45
E342	Fuel Holders, Producers & Accessories	-10.5	23.0	years	Dec-45
E343	Prime Movers	-10.5	23.0	years	Dec-45
E344	Generators	-10.5	23.0	years	Dec-45
E345	Accessory Electric Equipment	-10.5	23.0	years	Dec-45
E346	Miscellaneous Power Plant Equipment	-10.5	23.0	years	Dec-45
Lake Benton II Wind					
E340.1	Wind Rights	0.0	21.9	years	Nov-44
E341	Structures & Improvements	-10.8	21.9	years	Nov-44
E342	Fuel Holders, Producers & Accessories	-10.8	21.9	years	Nov-44
E343	Prime Movers	-10.8	21.9	years	Nov-44
E344	Generators	-10.8	21.9	years	Nov-44
E345	Accessory Electric Equipment	-10.8	21.9	years	Nov-44
E346	Miscellaneous Power Plant Equipment	-10.8	21.9	years	Nov-44

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Mower Wind					
E340.1	Wind Rights	0.0	23.3	years	Mar-46
E341	Structures & Improvements	-10.5	23.3	years	Mar-46
E342	Fuel Holders, Producers & Accessories	-10.5	23.3	years	Mar-46
E343	Prime Movers	-10.5	23.3	years	Mar-46
E344	Generators	-10.5	23.3	years	Mar-46
E345	Accessory Electric Equipment	-10.5	23.3	years	Mar-46
E346	Miscellaneous Power Plant Equipment	-10.5	23.3	years	Mar-46
Nobles Wind					
E340.1	Wind Rights	0.0	22.9	years	Nov-45
E341	Structures & Improvements	-8.5	22.9	years	Nov-45
E342	Fuel Holders, Producers & Accessories	-8.5	22.9	years	Nov-45
E343	Prime Movers	-8.5	22.9	years	Nov-45
E344	Generators	-8.5	22.9	years	Nov-45
E345	Accessory Electric Equipment	-8.5	22.9	years	Nov-45
E346	Miscellaneous Power Plant Equipment	-8.5	22.9	years	Nov-45
Pleasant Valley Wind					
E340.1	Wind Rights	0.0	18.0	years	Dec-40
E341	Structures & Improvements	-11.7	18.0	years	Dec-40
E342	Fuel Holders, Producers & Accessories	-11.7	18.0	years	Dec-40
E343	Prime Movers	-11.7	18.0	years	Dec-40
E344	Generators	-11.7	18.0	years	Dec-40
E345	Accessory Electric Equipment	-11.7	18.0	years	Dec-40
E346	Miscellaneous Power Plant Equipment	-11.7	18.0	years	Dec-40
Riverside					
E341	Structures & Improvements	-13.2	26.2	years	Feb-49
E342	Fuel Holders, Producers & Accessories	-13.2	26.2	years	Feb-49
E343	Prime Movers	-13.2	26.2	years	Feb-49
E344	Generators	-13.2	26.2	years	Feb-49
E345	Accessory Electric Equipment	-13.2	26.2	years	Feb-49
E346	Miscellaneous Power Plant Equipment	-13.2	26.2	years	Feb-49
Wind-to-Battery System					
E348.1	Energy Storage Equipment	-135.6	0.0	years	Jan-21

Electric Utility
Other Production (on acquisition dockets as approved by the Commission)

Account	Description	Proposed Net Salvage (%)	Proposed Remaining Life as of Estimated Acquisition Date		Est. Retirement date
Rock Aetna					
E340.1	Wind Rights	0.0	25.1	years	Jan-48
E341	Structures & Improvements	-10.5	25.1	years	Jan-48
E342	Fuel Holders, Producers & Accessories	-10.5	25.1	years	Jan-48
E343	Prime Movers	-10.5	25.1	years	Jan-48
E344	Generators	-10.5	25.1	years	Jan-48
E345	Accessory Electric Equipment	-10.5	25.1	years	Jan-48
E346	Miscellaneous Power Plant Equipment	-10.5	25.1	years	Jan-48
Northern Wind					
E340.1	Wind Rights	0.0	25.0	years	Dec-47
E341	Structures & Improvements	-10.5	25.0	years	Dec-47
E342	Fuel Holders, Producers & Accessories	-10.5	25.0	years	Dec-47
E343	Prime Movers	-10.5	25.0	years	Dec-47
E344	Generators	-10.5	25.0	years	Dec-47
E345	Accessory Electric Equipment	-10.5	25.0	years	Dec-47
E346	Miscellaneous Power Plant Equipment	-10.5	25.0	years	Dec-47

Gas Utility
Gas Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Maplewood					
G305	Structures & Improvements	-87.7	19.0	years	Dec-41
G311	LP Gas Equipment	-87.7	19.0	years	Dec-41
G320	Other Equipment	-87.7	19.0	years	Dec-41
Sibley					
G305	Structures & Improvements	-41.1	19.0	years	Dec-41
G311	LP Gas Equipment	-41.1	19.0	years	Dec-41
G320	Other Equipment	-41.1	19.0	years	Dec-41

Gas Utility
Gas Storage

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Wescott					
G361	Structures & Improvements	-19.6	19.0	years	Dec-41
G362	Gas Holders	-19.6	19.0	years	Dec-41
G363	Purification Equipment	-19.6	19.0	years	Dec-41
G363.1	Liquefaction Equipment	-19.6	19.0	years	Dec-41
G363.2	Vaporizing Equipment	-19.6	19.0	years	Dec-41
G363.3	Compressor Equipment	-19.6	19.0	years	Dec-41
G363.4	Measuring & Regulating Equipment	-19.6	19.0	years	Dec-41
G363.5	Other Equipment	-19.6	19.0	years	Dec-41

Northern States Power Company
Comparison of Present and Approved Lives
Electric and Gas Utilities Summary - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment B - Page 1 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs)	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Total Steam Production	$ 2,370,010,422	$ 1,853,899,866	10.0	9.0	-11.4	$ 87,251,840	5.7	-11.4	$ 136,978,697	$ 49,726,857
Total Nuclear Production	4,285,747,819	2,535,135,439	10.6	9.6	0.0	182,564,548	9.6	0.0	182,564,548	-
Total Hydro Production	29,059,513	19,574,129	11.6	10.6	-25.5	1,589,958	10.6	-25.5	1,589,958	-
Total Other Production ***	5,540,695,941	1,583,302,778	20.9	19.9	-10.2	227,302,799	21.5	-10.2	210,379,432	(16,923,367)
Total Gas Production	19,766,437	18,459,809	8.0	7.0	-55.0	1,739,542	19.0	-55.0	640,884	(1,098,658)
Total Gas Storage	70,160,786	60,697,591	3.4	2.4	-19.6	9,548,248	19.0	-19.6	1,221,827	(8,326,421)
Total Company	$ 12,315,440,918	$ 6,071,069,612				$ 509,996,935			$ 533,375,346	$ 23,378,411

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs)	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Grand Meadow and Nobles Wind Farms*	731,238,684	389,790,047				33,390,286			18,385,116	(15,005,170)
Gas Production **	19,766,437	18,459,809				1,739,542			640,884	(1,098,658)
Gas Storage **	70,160,786	60,697,591				9,548,248			1,221,827	(8,326,421)
Other Production	$ 821,165,907	$ 468,947,447				$ 44,678,076			$ 20,247,827	$ (24,430,249)

Total Change to Depreciation Expense $ 47,808,660

	Beginning Regulatory Balance 1/1/2022	Accumulated Amortization 1/1/2023 (est.)	Present: Approved Amortization Period (Yrs)	Present: Remaining Amortization Period (Yrs)	Present Amortization Expense	Proposed: Remaining Amortization Period (Yrs)	Proposed Amortization Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Total Steam Production - Regulatory Liability Amortization	$ 47,308,519	$ 30,220,963	7.3	6.3	$ 2,713,130	5.8	$ 2,964,695	$ 251,565

Total Change to Amortization Expense $ 251,565

Total Change to Depreciation and Amortization Expense $ 48,060,224

Note: All amounts shown in this schedule are represented as Northern States Power Company-Minnesota total company
*currently reflected in interim rates - Docket No. E002/M-20-620 to support economic relief and recovery in MN due to the COVID-19 pandamic - Wind Repowering Petition
** currently reflected in interim rates - proposed in Docket No. G002-GR-21-678 NSPM Gas Rate Case
*** includes Northern Wind and Rock Aetna with different plant & reserve balance dates

Northern States Power Company
Comparison of Present and Approved Lives
Steam Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Strorage ARL
Attachment B - Page 2 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E311 Structures & Improvements										
Black Dog	$ -	$ (11,954,173)	-	-	0.0	$ -	-	0.0	$ -	$ -
Allen S. King	39,721,551	28,960,233	16.5	14.5	-9.2	994,186	6.0	-9.2	2,402,617	1,408,431
Minnesota Valley	-	(1,093,877)	-	-	0.0	-	-	0.0	-	-
Red Wing	12,856,986	13,696,794	7.0	5.0	-23.5	436,317	5.0	-23.5	436,317	-
Sherco Unit 1 & 2	96,365,770	99,354,095	5.0	3.0	-15.1	3,854,302	3.0	-15.1	3,854,302	-
Sherco Unit 3	133,482,187	115,986,803	14.0	12.0	-7.9	2,336,706	8.0	-7.9	3,505,060	1,168,353
Wilmarth	11,645,698	11,075,941	7.0	5.0	-25.8	714,869	5.0	-25.8	714,869	-
Total/Composite	$ 294,072,193	$ 256,025,817	9.7	8.7	-11.8	$ 8,336,381	6.7	-11.8	$ 10,913,165	$ 2,576,784
E312 Boiler Plant Equipment										
Black Dog	$ -	$ 4,226,160	-	-	0.0	$ -	-	0.0	$ -	$ -
Allen S. King	525,951,646	276,974,172	16.5	14.5	-9.2	20,507,933	6.0	-9.2	49,560,838	29,052,905
Minnesota Valley	-	5,566,886	-	-	0.0	-	-	0.0	-	-
Red Wing	47,840,342	48,097,162	7.0	5.0	-23.5	2,197,132	5.0	-23.5	2,197,132	-
Sherco Unit 1	275,384,488	262,160,917	5.0	3.0	-15.1	18,268,876	3.0	-15.1	18,268,876	-
Sherco Unit 2	161,615,116	186,018,999	2.0	-	-15.1	-	-	-15.1	-	-
Sherco Unit 3	457,428,065	321,831,917	14.0	12.0	-7.9	14,311,080	8.0	-7.9	21,466,621	7,155,540
Wilmarth	44,393,918	46,111,781	7.0	5.0	-25.8	1,947,153	5.0	-25.8	1,947,153	-
Total/Composite	$ 1,512,613,575	$ 1,150,987,994	10.3	9.3	-11.5	$ 57,232,175	5.7	-11.5	$ 93,440,620	$ 36,208,445
E314 Turbogenerator Units										
Black Dog	$ -	$ 2,859,150	-	-	0.0	$ -	-	0.0	$ -	$ -
Allen S. King	94,307,445	53,291,979	16.5	14.5	-9.2	3,427,017	6.0	-9.2	8,281,958	4,854,941
Minnesota Valley	-	1,881,280	-	-	0.0	-	-	0.0	-	-
Red Wing	6,111,636	4,424,428	7.0	5.0	-23.5	624,688	5.0	-23.5	624,688	-
Sherco Unit 1	67,002,664	61,541,470	5.0	3.0	-15.1	5,192,865	3.0	-15.1	5,192,865	-
Sherco Unit 2	57,990,916	66,747,545	2.0	-	-15.1	-	-	-15.1	-	-
Sherco Unit 3	90,332,472	59,583,997	14.0	12.0	-7.9	3,157,062	8.0	-7.9	4,735,592	1,578,531
Wilmarth	6,175,415	5,053,684	7.0	5.0	-25.8	542,998	5.0	-25.8	542,998	-
Total/Composite	$ 321,920,548	$ 255,383,534	9.1	8.1	-11.7	$ 12,944,630	5.4	-11.7	$ 19,378,102	$ 6,433,472

Northern States Power Company
Comparison of Present and Approved Lives
Steam Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Strorage ARL
Attachment B - Page 3 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E315 Accessory Electric Equipment										
Black Dog	$ -	$ 2,732,148	-	-	0.0	$ -	-	0.0	$ -	$ -
Allen S. King	46,921,220	23,955,798	16.5	14.5	-9.2	1,881,529	6.0	-9.2	4,547,029	2,665,500
Minnesota Valley	-	521,324	-	-	0.0	-	-	0.0	-	-
Red Wing	1,905,550	2,150,924	7.0	5.0	-23.5	40,486	5.0	-23.5	40,486	-
Sherco Unit 1	47,333,714	46,532,051	5.0	3.0	-15.1	2,649,685	3.0	-15.1	2,649,685	-
Sherco Unit 2	6,747,297	7,766,139	2.0	-	-15.1	-	-	-15.1	-	-
Sherco Unit 3	83,085,559	59,674,012	14.0	12.0	-7.9	2,497,942	8.0	-7.9	3,746,913	1,248,971
Wilmarth	1,551,512	1,689,227	7.0	5.0	-25.8	52,515	5.0	-25.8	52,515	-
Total/Composite	$ 187,544,852	$ 145,021,622	9.8	8.8	-10.6	$ 7,122,157	5.7	-10.6	$ 11,036,628	$ 3,914,471
E316 Miscellaneous Power Plant Equipment										
Black Dog	$ -	$ 360,512	-	-	0.0	$ -	-	0.0	$ -	$ -
Allen S. King	7,979,927	6,568,157	16.5	14.5	-9.2	147,995	6.0	-9.2	357,654	209,659
Minnesota Valley	-	266,137	-	-	0.0	-	-	0.0	-	-
Red Wing	1,484,962	1,503,810	7.0	5.0	-23.5	66,024	5.0	-23.5	66,024	-
Sherco Unit 1	12,299,953	12,310,529	5.0	3.0	-15.1	615,572	3.0	-15.1	615,572	-
Sherco Unit 2	78,741	90,631	2.0	-	-15.1	-	-	-15.1	-	-
Sherco Unit 3	31,193,847	24,441,539	14.0	12.0	-7.9	768,052	8.0	-7.9	1,152,078	384,026
Wilmarth	821,824	939,586	7.0	5.0	-25.8	18,854	5.0	-25.8	18,854	-
Total/Composite	$ 53,859,254	$ 46,480,900	9.0	8.0	-10.5	$ 1,616,496	5.9	-10.5	$ 2,210,181	$ 593,685
Total Steam Production - Depreciation	$ 2,370,010,422	$ 1,853,899,866	10.0	9.0	-11.4	$ 87,251,840	5.7	-11.4	$ 136,978,697	$ 49,726,857

	Beginning Regulatory Balance 1/1/2022	Accumulated Amortization 1/1/2023 (est.)	Approved Amortization Period (Yrs)**	Remaining Amortization Period (Yrs) *	Present Amortization Expense	Remaining Amortization Period (Yrs)	Proposed Amortization Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Regulatory Liability Amortizations								
Black Dog Remediation	$ 33,150,000	$ 22,100,000	15.0	5.0	$ 2,210,000	5.0	$ 2,210,000	$ -
Sherco Unit 3 Deferral	14,158,519	8,120,963	21.0	12.0	503,130	8.0	754,695	251,565
Total Steam Production - Amortization	$ 47,308,519	$ 30,220,963	7.3	6.3	$ 2,713,130	5.8	$ 2,964,695	$ 251,565

	Plant Balance (1)	Reserve Balance (2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Total Steam Production	$ 2,417,318,941	$ 1,884,120,829	10.0	9.0	-11.4	$ 89,964,970	5.8	-11.4	$ 139,943,392	$ 49,978,421

*Remaining life as of 1/1/2022 due to passage of time.
**The Black Dog Remediation amortization period was set at 15 years beginning in 2013 per Docket No. E002/GR-12-961. The Sherco Unit 3 Deferral amortization period was set at 21 years beginning in 2014 per Docket No. E,G-002/D-14-181.

Northern States Power Company
Comparison of Present and Approved Lives
Nuclear Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Strorage ARL
Attachment B - Page 4 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E302 `										
Monticello	$ 130,758,472	$ 72,889,565	9.8	7.8	0.0	$ 7,419,091	7.8	0.0	$ 7,419,091	$ -
Prairie Island Unit 1 & 2	129,782,921	57,622,256	13.3	11.3	0.0	6,385,900	11.3	0.0	6,385,900	-
Total/Composite	$ 260,541,393	$ 130,511,821	10.4	9.4	0.0	$ 13,804,990	9.4	0.0	$ 13,804,990	$ -
E321 Structures & Improvements										
Monticello	$ 241,463,447	$ 163,348,380	9.8	7.8	0.0	$ 10,014,752	7.8	0.0	$ 10,014,752	$ -
Monticello Interim Storage	31,313,964	19,648,224	9.8	7.8	0.0	1,495,608	7.8	0.0	1,495,608	-
Prairie Island Unit 1 & 2	327,350,318	213,109,514	13.3	11.3	0.0	10,109,806	11.3	0.0	10,109,806	-
PI Interim Storage	23,901,891	12,571,785	13.3	11.3	0.0	1,002,664	11.3	0.0	1,002,664	-
Total/Composite	$ 624,029,620	$ 408,677,903	10.5	9.5	0.0	$ 22,622,830	9.5	0.0	$ 22,622,830	$ -
E322 Reactor Plant Equipment										
Monticello	$ 682,398,490	$ 441,858,744	9.8	7.8	0.0	$ 30,838,429	7.8	0.0	$ 30,838,429	$ -
Monticello Interim Storage	91,295,351	39,598,939	9.8	7.8	0.0	6,627,745	7.8	0.0	6,627,745	-
Prairie Island Unit 1 & 2	985,576,843	550,210,882	13.3	11.3	0.0	38,527,961	11.3	0.0	38,527,961	-
PI Interim Storage	210,406,709	100,259,965	13.3	11.3	0.0	9,747,499	11.3	0.0	9,747,499	-
Total/Composite	$ 1,969,677,394	$ 1,131,928,530	10.8	9.8	0.0	$ 85,741,635	9.8	0.0	$ 85,741,635	$ -
E323 Turbogenerator Units										
Monticello	$ 275,157,524	$ 157,704,181	9.8	7.8	0.0	$ 15,058,121	7.8	0.0	$ 15,058,121	$ -
Prairie Island Unit 1 & 2	386,760,015	207,613,793	13.3	11.3	0.0	15,853,648	11.3	0.0	15,853,648	-
Total/Composite	$ 661,917,539	$ 365,317,974	10.6	9.6	0.0	$ 30,911,769	9.6	0.0	$ 30,911,769	$ -
E324 Accessory Electric Equipment										
Monticello	$ 261,013,573	$ 147,059,312	9.8	7.8	0.0	$ 14,609,521	7.8	0.0	$ 14,609,521	$ -
Prairie Island Unit 1 & 2	301,173,387	206,916,661	13.3	11.3	0.0	8,341,303	11.3	0.0	8,341,303	-
Total/Composite	$ 562,186,960	$ 353,975,974	10.1	9.1	0.0	$ 22,950,824	9.1	0.0	$ 22,950,824	$ -
E325 Miscellaneous Power Plant Equipment										
Monticello	$ 88,561,760	$ 63,723,038	9.8	7.8	0.0	$ 3,184,452	7.8	0.0	$ 3,184,452	$ -
Prairie Island Unit 1 & 2	118,833,153	81,000,200	13.3	11.3	0.0	3,348,049	11.3	0.0	3,348,049	-
Total/Composite	$ 207,394,913	$ 144,723,237	10.6	9.6	0.0	$ 6,532,501	9.6	0.0	$ 6,532,501	$ -
Total Nuclear Production	$ 4,285,747,819	$ 2,535,135,439	10.6	9.6	0.0	$ 182,564,548	9.6	0.0	$ 182,564,548	$ -

*Remaining life as of 1/1/2022 due to passage of time.

Northern States Power Company
Comparison of Present and Approved Lives
Hydro Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment B - Page 5 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E302 Franchises & Consents										
Hennepin Island	$ 2,857,039	$ 1,663,839	13.2	11.2	0.0	$ 106,536	11.2	0.0	$ 106,536	$ -
Total/Composite	$ 2,857,039	$ 1,663,839	12.2	11.2	0.0	$ 106,536	11.2	0.0	$ 106,536	$ -
E331 Structures & Improvements										
Hennepin Island	$ 1,429,599	$ 1,000,503	13.2	11.2	-26.7	$ 72,393	11.2	-26.7	$ 72,393	$ -
St Croix Falls	37,924	41,966	7.0	5.0	-15.0	329	5.0	-15.0	329	-
Total/Composite	$ 1,467,523	$ 1,042,469	12.2	11.2	-26.4	$ 72,722	11.2	-26.4	$ 72,722	$ -
E332 Reservoirs, Dams & Waterways										
Hennepin Island	$ 4,398,484	$ 2,798,208	13.2	11.2	-26.7	$ 247,738	11.2	-26.7	$ 247,738	$ -
St Croix Falls	2,196,276	1,247,133	7.0	5.0	-15.0	255,717	5.0	-15.0	255,717	-
Upper Dam	4,491,476	4,487,640	13.2	11.2	-26.7	107,416	11.2	-26.7	107,416	-
Total/Composite	$ 11,086,236	$ 8,532,981	9.6	8.6	-24.4	$ 610,872	8.6	-24.4	$ 610,872	$ -
E333 Water Wheels, Turbines & Generators										
Hennepin Island	$ 10,156,575	$ 6,166,312	13.2	11.2	-26.7	$ 598,399	11.2	-26.7	$ 598,399	$ -
Total/Composite	$ 10,156,575	$ 6,166,312	12.2	11.2	-26.7	$ 598,399	11.2	-26.7	$ 598,399	$ -
E334 Accessory Electric Equipment										
Hennepin Island	$ 3,279,241	$ 2,068,953	13.2	11.2	-26.7	$ 186,236	11.2	-26.7	$ 186,236	$ -
Total/Composite	$ 3,279,241	$ 2,068,953	12.2	11.2	-26.7	$ 186,236	11.2	-26.7	$ 186,236	$ -
E335 Miscellaneous Power Plant Equipment										
Hennepin Island	$ 37,779	$ 43,337	13.2	11.2	-26.7	$ 404	11.2	-26.7	$ 404	$ -
Upper Dam	23,046	26,561	13.2	11.2	-26.7	236	11.2	-26.7	236	-
Total/Composite	$ 60,824	$ 69,899	12.2	11.2	-26.7	$ 640	11.2	-26.7	$ 640	$ -
E336 Rd, RR,Brdge-Hennepin Is										
Hennepin Island	152,075	29,677	13.2	11.2	-26.7	$ 14,554	11.2	-26.7	$ 14,554	$ -
Total/Composite	$ 152,075	$ 29,677	12.2	11.2	-26.7	$ 14,554	11.2	-26.7	$ 14,554	$ -
Total Hydro Production	$ 29,059,513	$ 19,574,129	11.6	10.6	-25.5	$ 1,589,958	10.6	-25.5	$ 1,589,958	$ -

*Remaining life as of 1/1/2022 due to passage of time.

Northern States Power Company
Comparison of Present and Approved Lives
Other Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Strorage ARL
Attachment B - Page 6 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E340.1 Wind Rights										
Border Winds	$ -	$ -	20.0	18.0	0.0	$ -	18.0	0.0	$ -	$ -
Courtenay Wind	2,085,661	510,254	20.9	18.9	0.0	83,355	18.9	0.0	83,355	-
Grand Meadow Wind	10,672,452	5,449,448	12.9	10.9	0.0	479,175	20.9	0.0	249,904	(229,270)
Mower Wind	627,881	44,952	25.2	23.2	0.0	25,126	23.2	0.0	25,126	-
Nobles Wind	3,884,834	1,863,631	14.9	12.9	0.0	156,682	22.9	0.0	88,262	(68,420)
Pleasant Valley Wind	-	-	20.0	18.0	0.0	-	18.0	0.0	-	-
Foxtail Wind	177,364	20,076	24.0	22.0	0.0	7,149	22.0	0.0	7,149	-
Lake Benton II Wind	-	-	23.9	21.9	0.0	-	21.9	0.0	-	-
Total/Composite	$ 17,448,192	$ 7,888,362	13.7	12.7	0.0	$ 751,488	21.1	0.0	$ 453,797	$ (297,690)
E341 Structures & Improvements										
Angus C. Anson Units 2 thru 4	$ 8,235,254	$ 5,872,771	24.4	22.4	-6.5	$ 129,365	22.4	-6.5	$ 129,365	$ -
Black Dog Unit 5	43,411,128	28,528,775	37.3	35.3	-10.3	548,263	35.3	-10.3	548,263	-
Black Dog Unit 6	13,825,936	5,664,919	37.3	35.3	-10.3	271,532	35.3	-10.3	271,532	-
Blazing Star 1 Wind	22,712,370	2,719,502	24.3	22.3	-11.6	1,014,686	22.3	-11.6	1,014,686	-
Blazing Star 2 Wind	26,563,875	2,292,545	25.1	23.1	-10.5	1,171,452	23.1	-10.5	1,171,452	-
Blue Lake Units 1 thru 4	1,153,723	1,105,885	24.4	22.4	-12.7	8,677	22.4	-12.7	8,677	-
Blue Lake Units 7 & 8	549,732	310,924	24.4	22.4	-12.7	13,778	22.4	-12.7	13,778	-
Border Winds	22,226,432	6,791,634	20.0	18.0	-9.5	974,795	18.0	-9.5	974,795	-
Community Wind North	2,710,368	264,652	25.0	23.0	-10.5	118,709	23.0	-10.5	118,709	-
Courtenay Wind	7,621,664	2,016,143	20.9	18.9	-10.4	338,528	18.9	-10.4	338,528	-
Crowned Ridge Wind	20,722,944	1,856,377	25.0	23.0	-10.5	914,890	23.0	-10.5	914,890	-
Dakota Range Wind	35,498,160	1,514,155	26.1	24.1	-10.5	1,564,785	24.1	-10.5	1,564,785	-
Freeborn Wind	63,028,255	4,540,765	25.4	23.4	-10.5	2,782,284	23.4	-10.5	2,782,284	-
Grand Meadow Wind	5,589,344	3,347,862	12.9	10.9	-12.5	269,739	20.9	-12.5	140,677	(129,062)
Granite City	533	625,826	-	-	0.0	-	-	0.0	-	-
High Bridge	71,147,957	24,007,554	27.4	25.4	-4.3	1,976,369	25.4	-4.3	1,976,369	-
Inver Hills	1,617,415	1,386,232	6.0	4.0	-19.4	136,240	4.0	-19.4	136,240	-
Jeffers Wind	3,706,351	402,515	25.0	23.0	-10.5	160,565	23.0	-10.5	160,565	-
Key City	786	477,078	-	-	0.0	-	-	0.0	-	-
Mower Wind	11,130,151	4,233,943	25.2	23.2	-10.5	347,624	23.2	-10.5	347,624	-
Nobles Wind	13,536,911	7,219,877	14.9	12.9	-8.5	578,889	22.9	-8.5	326,099	(252,790)
Pleasant Valley Wind	25,806,960	8,043,654	20.0	18.0	-11.7	1,154,596	18.0	-11.7	1,154,596	-
Riverside	52,858,845	30,420,064	28.2	26.2	-13.2	1,122,754	26.2	-13.2	1,122,754	-
Foxtail Wind	32,726,023	4,374,927	24.0	22.0	-9.1	1,424,053	22.0	-9.1	1,424,053	-
Lake Benton II Wind	33,079,253	4,503,702	23.9	21.9	-10.8	1,467,950	21.9	-10.8	1,467,950	-
Total/Composite	$ 519,460,368	$ 152,522,281	23.6	22.6	-9.8	$ 18,490,523	23.1	-9.8	$ 18,108,671	$ (381,852)
E342 Fuel Holders, Producers & Accessories										
Angus C. Anson Unit 2 & 3	$ 1,070,423	$ 957,338	20.0	18.0	-11.2	$ 12,943	18.0	-11.2	$ 12,943	$ -
Angus C. Anson Unit 4	13,506	1,566	24.4	22.4	-6.5	572	22.4	-6.5	572	-
Black Dog Unit 5	12,539,031	10,569,961	11.0	9.0	-7.2	319,098	9.0	-7.2	319,098	-
Black Dog Unit 6	9,512,175	1,222,956	37.3	35.3	-10.3	262,577	35.3	-10.3	262,577	-
Blazing Star 1 Wind	-	-	24.3	22.3	-11.6	-	22.3	-11.6	-	-
Blazing Star 2 Wind	-	-	25.1	23.1	-10.5	-	23.1	-10.5	-	-
Blue Lake Units 1 thru 4	1,340,395	1,723,248	2.5	0.5	-30.6	54,617	3.0	-30.6	9,103	(45,514)
Blue Lake Units 7 & 8	47,986	(12,366)	24.4	22.4	-12.7	2,966	22.4	-12.7	2,966	-
Community Wind North	-	-	25.0	23.0	-10.5	-	23.0	-10.5	-	-
Crowned Ridge Wind	-	-	25.0	23.0	-10.5	-	23.0	-10.5	-	-
Dakota Range Wind	-	-	26.1	24.1	-10.5	-	24.1	-10.5	-	-
Freeborn Wind	-	-	25.4	23.4	-10.5	-	23.4	-10.5	-	-
Granite City	-	209,852	-	-	0.0	-	-	0.0	-	-
High Bridge	753,399	(11,195)	27.4	25.4	-4.3	31,378	25.4	-4.3	31,378	-
Inver Hills	599,614	598,617	6.0	4.0	-19.4	29,330	4.0	-19.4	29,330	-
Jeffers Wind	-	-	25.0	23.0	-10.5	-	23.0	-10.5	-	-
Key City	-	115,375	-	-	0.0	-	-	0.0	-	-
Mower Wind	-	-	25.2	23.2	-10.5	-	23.2	-10.5	-	-
Riverside	2,059,988	154,688	28.2	26.2	-13.2	83,100	26.2	-13.2	83,100	-
Total/Composite	$ 27,936,517	$ 15,530,041	20.1	19.1	-10.2	$ 796,581	20.3	-10.2	$ 751,067	$ (45,514)

Northern States Power Company
Comparison of Present and Approved Lives
Other Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment B - Page 7 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E343 Prime Movers										
Black Dog Unit 5	$ 24,220,121	$ 16,258,113	11.0	9.0	-7.2	$ 1,078,429	9.0	-7.2	$ 1,078,429	$ -
High Bridge	67,960,213	22,802,973	27.4	25.4	-4.3	1,892,895	25.4	-4.3	1,892,895	-
Riverside	51,482,617	17,390,485	28.2	26.2	-13.2	1,560,605	26.2	-13.2	1,560,605	-
Total/Composite	$ 143,662,951	$ 56,451,570	22.8	21.8	-8.0	$ 4,531,928	21.8	-8.0	$ 4,531,928	$ -
E344 Generators										
Angus C. Anson Unit 2 & 3	$ 77,661,605	$ 63,883,362	20.0	18.0	-11.2	$ 1,248,686	18.0	-11.2	$ 1,248,686	$ -
Angus C. Anson Unit 4	33,793,801	17,673,819	24.4	22.4	-6.5	817,704	22.4	-6.5	817,704	-
Black Dog Unit 5	125,367,218	71,228,615	11.0	9.0	-7.2	7,018,338	9.0	-7.2	7,018,338	-
Black Dog Unit 6	62,375,841	8,861,173	37.3	35.3	-10.3	1,697,999	35.3	-10.3	1,697,999	-
Blazing Star 1 Wind	274,310,899	32,845,053	24.3	22.3	-11.6	12,254,974	22.3	-11.6	12,254,974	-
Blazing Star 2 Wind	305,321,580	26,350,204	25.1	23.1	-10.5	13,464,508	23.1	-10.5	13,464,508	-
Blue Lake Units 1 thru 4	21,359,097	27,471,319	2.5	0.5	-30.6	847,324	3.0	-30.6	141,221	(706,104)
Blue Lake Units 7 & 8	69,105,883	34,766,737	24.4	22.4	-12.7	1,924,803	22.4	-12.7	1,924,803	-
Border Winds	207,682,752	62,254,816	20.0	18.0	-9.5	9,175,433	18.0	-9.5	9,175,433	-
Community Wind North	26,412,178	2,795,195	25.0	23.0	-10.5	1,147,403	23.0	-10.5	1,147,403	-
Courtenay Wind	264,043,707	69,824,582	20.9	18.9	-10.4	11,729,083	18.9	-10.4	11,729,083	-
Crowned Ridge Wind	276,861,066	24,801,430	25.0	23.0	-10.5	12,223,046	23.0	-10.5	12,223,046	-
Dakota Range Wind	347,661,491	14,829,181	26.1	24.1	-10.5	15,325,177	24.1	-10.5	15,325,177	-
Freeborn Wind	236,613,706	17,023,591	25.4	23.4	-10.5	10,445,921	23.4	-10.5	10,445,921	-
Grand Meadow Wind	183,695,056	110,292,390	12.9	10.9	-12.5	8,840,784	20.9	-12.5	4,610,744	(4,230,040)
Granite City	-	3,258,848	-	-	0.0	-	-	0.0	-	-
High Bridge	210,175,920	62,354,635	27.4	25.4	-4.3	6,175,545	25.4	-4.3	6,175,545	-
Inver Hills	50,980,595	54,172,221	6.0	4.0	-19.4	1,674,652	4.0	-19.4	1,674,652	-
Jeffers Wind	38,324,900	4,647,306	25.0	23.0	-10.5	1,639,205	23.0	-10.5	1,639,205	-
Key City	-	2,558,380	-	-	0.0	-	-	0.0	-	-
Mower Wind	194,001,860	71,889,079	25.2	23.2	-10.5	6,141,508	23.2	-10.5	6,141,508	-
Nobles Wind	470,979,873	238,195,960	14.9	12.9	-8.5	21,148,620	22.9	-8.5	11,913,415	(9,235,205)
Pleasant Valley Wind	263,869,298	81,470,289	20.0	18.0	-11.7	11,848,429	18.0	-11.7	11,848,429	-
Riverside	176,489,317	47,741,191	28.2	26.2	-13.2	5,803,233	26.2	-13.2	5,803,233	-
Foxtail Wind	204,085,404	27,282,835	24.0	22.0	-9.1	8,880,652	22.0	-9.1	8,880,652	-
Lake Benton II Wind	116,607,126	15,875,925	23.9	21.9	-10.8	5,174,647	21.9	-10.8	5,174,647	-
Total/Composite	$ 4,237,780,172	$ 1,194,348,138	20.7	19.7	-10.3	$ 176,647,675	21.4	-10.3	$ 162,476,326	$ (14,171,349)
E345 Accessory Electric Equipment										
Angus C. Anson Unit 2 & 3	$ 4,876,179	$ 3,221,614	20.0	18.0	-11.2	$ 122,261	18.0	-11.2	$ 122,261	$ -
Angus C. Anson Unit 4	4,930,962	2,117,491	24.4	22.4	-6.5	139,910	22.4	-6.5	139,910	-
Black Dog Unit 5	28,111,443	20,389,077	11.0	9.0	-7.2	1,082,932	9.0	-7.2	1,082,932	-
Black Dog Unit 6	11,141,445	1,485,451	37.3	35.3	-10.3	306,050	35.3	-10.3	306,050	-
Blazing Star 1 Wind	10,359,276	1,240,384	24.3	22.3	-11.6	462,806	22.3	-11.6	462,806	-
Blazing Star 2 Wind	4,959,722	428,039	25.1	23.1	-10.5	218,721	23.1	-10.5	218,721	-
Blue Lake Units 1 thru 4	2,726,341	3,028,594	2.5	0.5	-30.6	1,064,016	3.0	-30.6	177,336	(886,680)
Blue Lake Units 7 & 8	8,007,188	4,529,726	24.4	22.4	-12.7	200,642	22.4	-12.7	200,642	-
Border Winds	34,794,649	10,521,585	20.0	18.0	-9.5	1,532,142	18.0	-9.5	1,532,142	-
Community Wind North	1,310,167	127,930	25.0	23.0	-10.5	57,383	23.0	-10.5	57,383	-
Courtenay Wind	10,040,328	2,578,743	20.9	18.9	-10.4	450,041	18.9	-10.4	450,041	-
Crowned Ridge Wind	11,464,510	1,026,764	25.0	23.0	-10.5	506,153	23.0	-10.5	506,153	-
Dakota Range Wind	11,411,256	486,760	26.1	24.1	-10.5	503,016	24.1	-10.5	503,016	-
Freeborn Wind	685,711	45,780	25.4	23.4	-10.5	30,424	23.4	-10.5	30,424	-
Grand Meadow Wind	12,073,394	7,550,621	12.9	10.9	-12.5	553,390	20.9	-12.5	288,610	(264,780)
Granite City	-	67,166	-	-	0.0	-	-	0.0	-	-
High Bridge	52,014,326	17,680,530	27.4	25.4	-4.3	1,439,780	25.4	-4.3	1,439,780	-
Inver Hills	4,309,713	3,939,222	6.0	4.0	-19.4	301,644	4.0	-19.4	301,644	-
Jeffers Wind	507,681	57,590	25.0	23.0	-10.5	21,887	23.0	-10.5	21,887	-
Key City	-	447,200	-	-	0.0	-	-	0.0	-	-
Mower Wind	2,275,151	841,616	25.2	23.2	-10.5	72,087	23.2	-10.5	72,087	-
Nobles Wind	29,969,729	15,439,256	14.9	12.9	-8.5	1,323,868	22.9	-8.5	745,760	(578,108)
Pleasant Valley Wind	42,507,679	13,123,034	20.0	18.0	-11.7	1,908,780	18.0	-11.7	1,908,780	-
Riverside	40,495,707	15,076,077	28.2	26.2	-13.2	1,174,239	26.2	-13.2	1,174,239	-
Foxtail Wind	-	-	24.0	22.0	-9.1	-	22.0	-9.1	-	-
Lake Benton II Wind	11,207,318	1,525,372	23.9	21.9	-10.8	497,367	21.9	-10.8	497,367	-
Total/Composite	$ 340,179,876	$ 126,975,624	18.7	17.7	-9.9	$ 13,969,539	20.2	-9.9	$ 12,239,970	$ (1,729,568)

Northern States Power Company
Comparison of Present and Approved Lives
Other Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment B - Page 8 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
E346 Miscellaneous Power Plant Equipment										
Angus C. Anson Unit 2 & 3	$ 2,631,260	$ 2,236,674	20.0	18.0	-11.2	$ 38,294	18.0	-11.2	$ 38,294	$ -
Angus C. Anson Unit 4	20,727	4,321	24.4	22.4	-6.5	793	22.4	-6.5	793	-
Black Dog Unit 5	5,657,756	5,677,574	11.0	9.0	-7.2	43,060	9.0	-7.2	43,060	-
Black Dog Unit 6	5,817,664	3,971,715	37.3	35.3	-10.3	69,268	35.3	-10.3	69,268	-
Blazing Star 1 Wind	-	-	24.3	22.3	-11.6	-	22.3	-11.6	-	-
Blazing Star 2 Wind	1,887,590	162,905	25.1	23.1	-10.5	83,242	23.1	-10.5	83,242	-
Blue Lake Units 1 thru 4	886,743	990,147	2.5	0.5	-30.6	335,880	3.0	-30.6	55,980	(279,900)
Blue Lake Units 7 & 8	32,958	16,162	24.4	22.4	-12.7	937	22.4	-12.7	937	-
Border Winds	228,153	69,982	20.0	18.0	-9.5	9,991	18.0	-9.5	9,991	-
Community Wind North	81,604	7,968	25.0	23.0	-10.5	3,574	23.0	-10.5	3,574	-
Courtenay Wind	36,482	9,805	20.9	18.9	-10.4	1,612	18.9	-10.4	1,612	-
Crowned Ridge Wind	194,943	17,463	25.0	23.0	-10.5	8,606	23.0	-10.5	8,606	-
Dakota Range Wind	474,071	20,139	26.1	24.1	-10.5	20,901	24.1	-10.5	20,901	-
Freeborn Wind	20,488,106	1,474,057	25.4	23.4	-10.5	904,500	23.4	-10.5	904,500	-
Grand Meadow Wind	209,119	130,174	12.9	10.9	-12.5	9,641	20.9	-12.5	5,028	(4,613)
Granite City	-	6,693	-	-	0.0	-	-	0.0	-	-
High Bridge	7,144,763	2,765,106	27.4	25.4	-4.3	184,523	25.4	-4.3	184,523	-
Inver Hills	617,845	716,124	6.0	4.0	-19.4	5,396	4.0	-19.4	5,396	-
Jeffers Wind	190,058	21,625	25.0	23.0	-10.5	8,191	23.0	-10.5	8,191	-
Key City	-	132,230	-	-	0.0	-	-	0.0	-	-
Mower Wind	765,024	282,995	25.2	23.2	-10.5	24,240	23.2	-10.5	24,240	-
Nobles Wind	627,971	300,826	14.9	12.9	-8.5	29,498	22.9	-8.5	16,617	(12,881)
Pleasant Valley Wind	292,092	90,971	20.0	18.0	-11.7	13,072	18.0	-11.7	13,072	-
Riverside	11,142,086	6,001,051	28.2	26.2	-13.2	252,358	26.2	-13.2	252,358	-
Foxtail Wind	-	-	24.0	22.0	-9.1	-	22.0	-9.1	-	-
Lake Benton II Wind	-	-	23.9	21.9	-10.8	-	21.9	-10.8	-	-
Total/Composite	$ 59,427,014	$ 25,106,706	20.8	19.8	-10.3	$ 2,047,575	23.1	-10.3	$ 1,750,182	$ (297,394)
E348.1 Energy Storage Equipment										
Wind-to-Battery System	$ 4,128,902	4,128,902	-	-	0.0	$ -	-	0.0	-	$ -
Total/Composite	$ 4,128,902	$ 4,128,902	0.0	0.0	0.0	$ -	0.0	0.0	$ -	$ -

	Plant Balance 12/31/2022	Reserve Balance 12/31/2022	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
Est ISD December 2022										
Northern Wind										
E340.1 Wind Rights	$ -	$ -	25.0	24.9	-10.5	$ -	24.9	-10.5	$ -	$ -
E341 Structures & Improvements	-	-	25.0	24.9	-10.5	-	24.9	-10.5	-	-
E344 Generators	190,671,949	351,154	25.0	24.9	-10.5	8,441,793	24.9	-10.5	8,441,793	-
E345 Accessory Electric Equipment	-	-	25.0	24.9	-10.5	-	24.9	-10.5	-	-
E346 Miscellaneous Power Plant Equipment	-	-	25.0	24.9	-10.5	-	24.9	-10.5	-	-
Total Plant	$ 190,671,949	$ 351,154	25.0	24.9	-10.5	$ 8,441,793	24.9	-10.5	$ 8,441,793	$ -

	Plant Balance 1/1/2023	Reserve Balance 1/1/2023	Approved Rem Life (Yrs)	Rem. Life (Yrs) *	Net Salv %	Depreciation Expense	Rem. Life (Yrs)	Net Salv %	Depreciation Expense	Less Present Expense
Est ISD January 2023										
Rock Aetna Wind										
E340.1 Wind Rights	$ -	$ -	25.0	25.1	-10.5	$ -	25.1	-10.5	$ -	$ -
E341 Structures & Improvements	-	-	25.0	25.1	-10.5	-	25.1	-10.5	-	-
E344 Generators	36,927,601	-	25.0	25.1	-10.5	1,625,697	25.1	-10.5	1,625,697	-
E345 Accessory Electric Equipment	-	-	25.0	25.1	-10.5	-	25.1	-10.5	-	-
E346 Miscellaneous Power Plant Equipment	-	-	25.0	25.1	-10.5	-	25.1	-10.5	-	-
Total Plant	$ -	$ -	25.0	#DIV/0!	#DIV/0!	$ 1,625,697	#DIV/0!	#DIV/0!	$ 1,625,697	$ -
Total Other Production	$ 5,540,695,941	$ 1,583,302,778	20.9	19.9	-10.2	$ 227,302,799	21.5	-10.2	$ 210,379,432	$ (16,923,367)

*Remaining life as of 1/1/2022 due to passage of time.

Northern States Power Company
Comparison of Present and Approved Lives
Gas Production - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment B - Page 9 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
G305 Structures & Improvements										
Maplewood	$ 1,670,673	$ 2,010,142	9.0	7.0	-87.7	$ 160,816	19.0	-87.7	$ 59,248	$ (101,568)
Sibley	1,166,477	1,009,462	9.0	7.0	-41.1	90,920	19.0	-41.1	33,497	(57,423)
Total/Composite	$ 2,837,150	$ 3,019,604	8.0	7.0	-68.5	$ 251,735	19.0	-68.5	$ 92,745	$ (158,991)
G311 LP Gas Equipment										
Maplewood	$ 3,766,755	$ 5,103,830	9.0	7.0	-87.7	$ 280,910	19.0	-87.7	$ 103,493	$ (177,417)
Sibley	12,089,035	9,238,727	9.0	7.0	-41.1	1,116,986	19.0	-41.1	411,521	(705,465)
Total/Composite	$ 15,855,789	$ 14,342,557	8.0	7.0	-52.2	$ 1,397,896	19.0	-52.2	$ 515,014	$ (882,881)
G320 Other Equipment										
Maplewood	$ 455,629	$ 490,449	9.0	7.0	-87.7	$ 52,110	19.0	-87.7	$ 19,198	$ (32,911)
Sibley	617,868	607,199	9.0	7.0	-41.1	37,802	19.0	-41.1	13,927	(23,875)
Total/Composite	$ 1,073,498	$ 1,097,648	8.0	7.0	-60.9	$ 89,911	19.0	-60.9	$ 33,125	$ (56,786)
Total Gas Production	$ 19,766,437	$ 18,459,809	8.0	7.0	-55.0	$ 1,739,542	19.0	-55.0	$ 640,884	$ (1,098,658)

*Remaining life as of 1/1/2022 due to passage of time.

Northern States Power Company
Comparison of Present and Approved Lives
Gas Storage - 2022

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Strorage ARL
Attachment B - Page 10 of 10

	Plant Balance 1/1/2022	Reserve Balance 1/1/2023 (est.)	Present: Approved Rem Life (Yrs)	Present: Rem. Life (Yrs) *	Present: Net Salv %	Present: Depreciation Expense	Proposed: Rem. Life (Yrs)	Proposed: Net Salv %	Proposed: Depreciation Expense	Proposed Less Present Expense
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
G361 Structures & Improvements										
Wescott	$ 6,500,975	$ 7,257,884	3.0	1.0	-19.6	$ 517,282	19.0	-19.6	$ 27,225	$ (490,057)
G362 Gas Holders										
Wescott	$ 8,260,593	$ 9,566,022	3.0	1.0	-19.6	$ 313,647	19.0	-19.6	$ 16,508	$ (297,139)
G363 Purification Equipment										
Wescott	$ 8,004,034	$ 5,485,533	3.0	1.0	-19.6	$ 4,087,291	19.0	-19.6	$ 215,121	$ (3,872,171)
G363.1 Liquefaction Equipment										
Wescott	$ 8,083,589	$ 7,392,309	3.0	1.0	-19.6	$ 2,275,664	19.0	-19.6	$ 119,772	$ (2,155,892)
G363.2 Vaporizing Equipment										
Wescott	$ 9,741,410	$ 8,896,669	7.0	5.0	-19.6	$ 550,811	19.0	-19.6	$ 144,950	$ (405,861)
G363.3 Compressor Equipment										
Wescott	$ 24,028,293	$ 16,000,932	12.0	10.0	-19.6	$ 1,273,691	19.0	-19.6	$ 670,364	$ (603,327)
G363.4 Measuring & Regulating Equipment										
Wescott	$ 73,634	$ 83,775	3.0	1.0	-19.6	$ 4,291	19.0	-19.6	$ 226	$ (4,065)
G363.5 Other Equipment										
Wescott	$ 5,468,258	$ 6,014,467	3.0	1.0	-19.6	$ 525,570	19.0	-19.6	$ 27,662	$ (497,908)
Total Gas Storage	$ 70,160,786	$ 60,697,591	3.4	2.4	-19.6	$ 9,548,248	19.0	-19.6	$ 1,221,827	$ (8,326,421)

*Remaining life as of 1/1/2022 due to passage of time.

Northern States Power Company
2021 Plant In-service Rollforward
Electric and Gas Utilities Summary

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment C - Page 1 of 2

Electric Utility

FERC Account	Account Description	Beginning Balance 1/1/2021	Additions	Retirements	Transfers	Adjustments	Ending Balance 12/31/2021
Steam							
310	Land & Land Rights - Fee	$ 8,517,686	$ 92,314	$ -	$ -	$ -	$ 8,610,000
310	Land & Land Rights - Other	1,516,948	-	-	-	-	1,516,948
311	Structures & Improvements	292,341,488	2,134,796	(404,091)	-	-	294,072,193
312	Boiler Plant Equipment	1,485,210,368	33,209,635	(5,806,427)	-	-	1,512,613,575
314	Turbogenerator Units	318,360,824	4,002,441	(442,717)	-	-	321,920,548
315	Accessory Electric Equipment	187,297,955	722,607	(475,710)	-	-	187,544,852
316	Miscellaneous Power Plant Equipment	54,142,199	236,901	(519,846)	-	-	53,859,254
		$ 2,347,387,469	**$ 40,398,693**	**$ (7,648,792)**	**$ -**	**$ -**	**$ 2,380,137,370**
Nuclear							
302	Franchises & Consents	$ 251,384,968	$ 9,156,425	$ -	$ -	$ -	$ 260,541,392
320	Land & Land Rights - Fee	1,755,983	-	-	-	-	1,755,983
320	Land and Land Rights - Other	1,729	-	-	-	-	1,729
321	Structures & Improvements	599,985,309	24,961,342	(917,031)	-	-	624,029,620
322	Reactor Plant Equipment	1,941,989,331	27,792,238	(104,174)	-	-	1,969,677,394
323	Turbogenerator Units	633,418,531	28,500,749	(1,741)	-	-	661,917,539
324	Accessory Electric Equipment	558,179,600	4,243,389	(236,030)	-	-	562,186,960
325	Miscellaneous Power Plant Equipment	206,832,867	885,657	(323,610)	-	-	207,394,913
		$ 4,193,548,317	**$ 95,539,799**	**$ (1,582,585)**	**$ -**	**$ -**	**$ 4,287,505,531**
Hydro							
302	Franchises & Consents	$ 2,857,039	$ -	$ -	$ -	$ -	$ 2,857,039
330	Land & Land Rights - Fee	292,863	-	-	-	-	292,863
330	Land & Land Rights - Other	1,400,213	-	-	-	-	1,400,213
331	Structures & Improvements	1,467,523	-	-	-	-	1,467,523
332	Reservoirs, Dams & Waterways	11,086,236	-	-	-	-	11,086,236
333	Water Wheels, Turbines & Generators	10,156,575	-	-	-	-	10,156,575
334	Accessory Electric Equipment	3,274,339	6,020	(1,118)	-	-	3,279,241
335	Miscellaneous Power Plant Equipment	60,824	-	-	-	-	60,824
336	Prod, Road, RR & Brdg	143,714	8,361	-	-	-	152,075
		$ 30,739,326	**$ 14,381**	**$ (1,118)**	**$ -**	**$ -**	**$ 30,752,590**
Other							
340	Land & Land Rights - Fee	$ 6,059,620	$ (398,295)	$ -	$ (14,802)	$ 20,554	$ 5,667,077
340	Land & Land Rights - Other	10,367,652	-	-	-	-	10,367,652
340.4	Wind Rights	16,868,552	695,867	-	-	(116,227)	17,448,192
341	Structures & Improvements	381,043,586	100,417,386	(200,822)	2,702,058	-	483,962,208
342	Fuel Holders, Producers & Accessories	26,957,487	1,127,880	(148,851)	-	-	27,936,517
343	Prime Movers	141,324,865	2,644,680	(306,594)	-	-	143,662,951
344	Generators	3,129,133,974	724,591,700	(10,811,737)	47,204,746	-	3,890,118,683
345	Accessory Electric Equipment	317,142,570	11,125,928	(52,215)	552,337	-	328,768,620
346	Miscellaneous Power Plant Equipment	33,485,275	25,391,991	(110,047)	185,724	-	58,952,944
348.1	Energy Storage Equipment	4,128,902	-	-	-	-	4,128,902
		$ 4,066,512,483	**$ 865,597,137**	**$ (11,630,265)**	**$ 50,630,064**	**$ (95,673)**	**$ 4,971,013,745**
Electric Utility Total		**$ 10,638,187,595**	**$ 1,001,550,011**	**$ (20,862,761)**	**$ 50,630,064**	**$ (95,673)**	**$ 11,669,409,236**

Northern States Power Company
2021 Plant In-service Rollforward
Electric and Gas Utilities Summary

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment C - Page 2 of 2

Gas Utility

FERC Account	Account Description	Beginning Balance 1/1/2021	Additions	Retirements	Transfers	Adjustments	Ending Balance 12/31/2021
Production							
304	Land & Land Rights - Fee	$ 356,015	$ -	$ -	$ -	$ -	$ 356,015
304	Land & Land Rights - Other	34,536	-	-	-	-	34,536
305	Structures & Improvements	2,777,523	59,627	-	-	-	2,837,150
311	LP Gas Equipment	13,241,932	2,631,795	(17,939)	-	-	15,855,789
320	Other Equipment	1,091,608	25,064	(43,174)	-	-	1,073,498
		$ 17,501,615	**$ 2,716,487**	**$ (61,113)**	**$ -**	**$ -**	**$ 20,156,989**
Storage							
360	Land & Land Rights - Fee	$ 349,574	$ -	$ -	$ -	$ -	$ 349,574
360	Land & Land Rights - Other	11,264	-	-	-	-	11,264
361	Structures & Improvements	6,456,692	44,283	-	-	-	6,500,975
362	Gas Holders	8,260,593	-	-	-	-	8,260,593
363	Purification Equipment	985,962	7,018,072	-	-	-	8,004,034
363.1	Liquefaction Equipment	7,073,121	1,010,469	-	-	-	8,083,589
363.2	Vaporizing Equipment	9,363,389	378,021	-	-	-	9,741,410
363.3	Compressor Equipment	23,752,052	276,241	-	-	-	24,028,293
363.4	Measuring & Regulating Equipment	73,634	-	-	-	-	73,634
363.5	Other Equipment	5,433,374	34,884	-	-	-	5,468,258
		$ 61,759,654	**$ 8,761,971**	**$ -**	**$ -**	**$ -**	**$ 70,521,625**
Gas Utility Total		**$ 79,261,269**	**$ 11,478,458**	**$ (61,113)**	**$ -**	**$ -**	**$ 90,678,613**

Northern States Power Company
2021 Accumulated Depreciation Rollforward
Electric and Gas Utilities Summary

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment D - Page 1 of 2

Electric Utility

FERC Account	Account Description	Beginning Balance 1/1/2021	Credits: Accruals	Credits: Gross Salvage	Debits: Retirements	Debits: Cost of Removal	Transfers, Adjustments, and Other Credits (Debits)	Ending Balance 12/31/2021
Steam								
311	Structures & Improvements	$ 241,056,460	$ 8,126,079	$ (316)	$ 404,091	$ 1,088,696	$ (0)	$ 247,689,436
312	Boiler Plant Equipment	1,020,492,191	67,545,959	189,616	5,806,427	1,905,727	(0)	1,080,515,611
314	Turbogenerator Units	219,356,039	18,049,069	-	442,717	73,002	0	236,889,388
315	Accessory Electric Equipment	129,908,007	7,816,430	14	475,710	235,565	(0)	137,013,177
316	Miscellaneous Power Plant Equipment	43,882,302	1,608,165	-	519,846	138,815	0	44,831,805
		$ 1,654,694,999	**$ 103,145,702**	**$ 189,314**	**$ 7,648,792**	**$ 3,441,806**	**$ (0)**	**$ 1,746,939,416**
Nuclear								
302	Franchises & Consents	$ 103,548,490	$ 13,158,341	$ -	$ -	$ -	$ -	$ 116,706,831
321	Structures & Improvements	366,070,728	21,036,894	-	917,031	135,518	-	386,055,073
322	Reactor Plant Equipment	962,283,987	84,048,405	-	104,174	41,322	-	1,046,186,896
323	Turbogenerator Units	304,591,799	29,816,386	-	1,741	239	-	334,406,205
324	Accessory Electric Equipment	308,488,036	22,836,187	-	236,030	63,044	-	331,025,150
325	Miscellaneous Power Plant Equipment	132,061,999	6,470,975	-	323,610	18,628	-	138,190,737
		$ 2,177,045,038	**$ 177,367,188**	**$ -**	**$ 1,582,585**	**$ 258,750**	**$ -**	**$ 2,352,570,891**
Hydro								
302	Franchises & Consents	$ 1,450,476	$ 106,828	$ -	$ -	$ -	$ -	$ 1,557,303
331	Structures & Improvements	896,826	72,921	-	-	-	-	969,747
332	Reservoirs, Dams & Waterways	7,310,264	611,845	-	-	-	-	7,922,109
333	Water Wheels, Turbines & Generators	4,967,875	600,038	-	-	-	-	5,567,913
334	Accessory Electric Equipment	1,697,107	186,688	-	1,118	(40)	-	1,882,717
335	Miscellaneous Power Plant Equipment	68,617	642	-	-	-	-	69,259
336	Miscellaneous Power Plant Equipment	571	14,551	-	-	-	-	15,123
		$ 16,391,737	**$ 1,593,512**	**$ -**	**$ 1,118**	**$ (40)**	**$ -**	**$ 17,984,171**
Other								
114	Acq Adjustment	$ 197,525	$ 2,989,478	$ -	$ -	$ -	$ (699)	$ 3,186,304
340	Wind Rights	$ 6,391,805	$ 745,069	$ -	$ -	$ -	$ (0)	$ 7,136,874
341	Structures & Improvements	115,020,434	15,687,263	-	200,822	36,683	3,612,195	134,082,388
342	Fuel Holders, Producers & Accessories	14,231,622	771,134	-	148,851	120,445	-	14,733,460
343	Prime Movers	47,826,614	4,463,556	-	306,594	63,935	-	51,919,642
344	Generators	815,391,224	154,595,570	-	10,811,738	1,883,779	60,905,182	1,018,196,459
345	Accessory Electric Equipment	100,566,928	12,485,343	11,404	52,215	701,801	712,682	113,022,341
346	Miscellaneous Power Plant Equipment	21,610,204	1,348,459	-	110,047	28,364	239,641	23,059,893
348	Energy Storage Equipment	3,242,796	886,107	-	-	-	-	4,128,902
		$ 1,124,479,151	**$ 193,971,980**	**$ 11,404**	**$ 11,630,266**	**$ 2,835,007**	**$ 65,469,001**	**$ 1,369,466,263**
Electric Utility Total		**$ 4,972,610,925**	**$ 476,078,382**	**$ 200,718**	**$ 20,862,761**	**$ 6,535,523**	**$ 65,469,001**	**$ 5,486,960,741**

Northern States Power Company
2021 Accumulated Depreciation Rollforward
Electric and Gas Utilities Summary

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment D - Page 2 of 2

Gas Utility

FERC Account	Account Description	Beginning Balance 1/1/2021	Credits: Accruals	Credits: Gross Salvage	Debits: Retirements*	Debits: Cost of Removal	Transfers, Adjustments, and Other Credits (Debits)	Ending Balance 12/31/2021
G Prod								
305	Structures & Improvements	$ 2,526,930	$ 240,938	$ -	$ -	$ -	$ -	$ 2,767,869
311	LP Gas Equipment	11,938,576	1,120,412	-	17,939	96,387	-	12,944,662
320	Other Equipment	972,139	86,729	-	43,174	7,957	-	1,007,736
		$ 15,437,645	**$ 1,448,079**	**$ -**	**$ 61,113**	**$ 104,344**	**$ -**	**$ 16,720,267**
Gas Storage								
361	Structures & Improvements	$ 6,237,141	$ 503,462	$ -	$ -	$ 1	$ -	$ 6,740,602
362	Gas Holders	8,938,728	313,647	-	-	-	-	9,252,375
363	Purification Equipment	1,099,517	298,725	-	-	-	-	1,398,242
363.1	Liquefaction Equipment	3,366,993	1,749,652	-	-	-	-	5,116,645
363.2	Vaporizing Equipment	7,866,785	479,072	-	-	-	-	8,345,857
363.3	Compressor Equipment	13,478,624	1,248,614	-	-	(3)	-	14,727,241
363.4	Measuring & Regulating Equipment	75,192	4,291	-	-	-	-	79,483
363.5	Other Equipment	4,959,104	530,605	-	-	813	-	5,488,897
		$ 46,022,086	**$ 5,128,068**	**$ -**	**$ -**	**$ 811**	**$ -**	**$ 51,149,343**
Gas Utility Total		**$ 61,459,731**	**$ 6,576,147**	**$ -**	**$ 61,113**	**$ 105,155**	**$ -**	**$ 67,869,610**

Note: All amounts shown in this schedule are represented as Northern States Power Company-Minnesota total company

Northern States Power Company
2021 Summary of Annual Depreciation Accruals
Electric and Gas Utilities Summary
Electric Utility

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment E - Page 1 of 2

FERC Account	Account Description	1/1/2021 Beginning Plant Balance	Est. Future Net Salvage %	Est. Future Net Salvage Amount	1/1/2021 Beginning Depreciation Reserve	Net Balance	Depr Life (Yrs)	Annual Accrual	Reserve Ratio
Steam									
311	Structures & Improvements	$ 292,341,488	-10.8%	$ (31,501,352)	$ 241,056,460	$ 82,786,380	8.0	$ 10,335,384	74.44%
312	Boiler Plant Equipment	1,485,210,368	-10.6%	(157,814,245)	1,020,492,191	622,532,422	9.4	66,296,013	62.11%
314	Turbogenerator Units	318,360,824	-10.8%	(34,281,656)	219,356,039	133,286,441	7.7	17,400,973	62.20%
315	Accessory Electric Equipment	187,297,955	-9.3%	(17,435,306)	129,908,007	74,825,254	10.2	7,351,552	63.45%
316	Miscellaneous Power Plant Equipment	54,142,199	-8.9%	(4,844,642)	43,882,302	15,104,540	9.9	1,531,006	74.39%
								$ 102,914,928	
Nuclear									
302	Franchises & Consents	$ 251,384,968	0.0%	$ -	$ 103,548,490	$ 147,836,478	11.4	$ 12,935,877	41.19%
321	Structures & Improvements	599,985,309	0.0%	-	366,070,728	233,914,581	11.3	20,649,677	61.01%
322	Reactor Plant Equipment	1,941,989,331	0.0%	-	962,283,987	979,705,345	11.7	83,451,063	49.55%
323	Turbogenerator Units	633,418,531	0.0%	-	304,591,799	328,826,732	11.6	28,225,623	48.09%
324	Accessory Electric Equipment	558,179,600	0.0%	-	308,488,036	249,691,564	11.1	22,581,855	55.27%
325	Miscellaneous Power Plant Equipment	206,832,867	0.0%	-	132,061,999	74,770,868	11.6	6,444,646	63.85%
								$ 174,288,743	
Hydro									
302	Franchises & Consents	$ 2,857,039	0.0%	$ -	$ 1,450,476	$ 1,406,563	13.2	$ 106,558	50.77%
331	Structures & Improvements	1,467,523	-25.9%	(380,150)	896,826	950,847	13.2	71,997	48.54%
332	Reservoirs, Dams & Waterways	11,086,236	-22.7%	(2,514,655)	7,310,264	6,290,627	10.8	584,632	53.75%
333	Water Wheels, Turbines & Generators	10,156,575	-26.4%	(2,681,336)	4,967,875	7,870,036	13.2	596,215	38.70%
334	Accessory Electric Equipment	3,274,339	-26.4%	(864,425)	1,697,107	2,441,657	13.2	184,974	41.01%
335	Miscellaneous Power Plant Equipment	60,824	-26.4%	(16,058)	68,617	8,265	13.2	626	89.25%
336	Miscellaneous Power Plant Equipment	143,714	-26.4%	(37,940)	571	181,083	13.2	13,718	0.31%
								$ 1,558,720	
Other									
114	Acq Adj	$ -	0.0%	$ -	$ -	$ -	(1.0)	$ -	0.00%
340	Wind Rights	$ 16,868,552	0.0%	$ -	$ 6,391,805	$ 10,476,748	14.3	$ 730,545	37.89%
341	Structures & Improvements	381,043,586	-8.2%	(31,216,083)	115,020,434	297,239,235	24.1	12,312,784	27.90%
342	Fuel Holders, Producers & Accessories	26,957,487	-10.2%	(2,758,005)	14,231,622	15,483,871	20.9	740,813	47.89%
343	Prime Movers	141,324,865	-7.6%	(10,785,017)	47,826,614	104,283,268	23.6	4,419,647	31.44%
344	Generators	3,129,133,974	-8.6%	(267,894,521)	815,391,224	2,581,637,271	19.3	134,005,545	24.00%
345	Accessory Electric Equipment	317,142,570	-8.3%	(26,396,522)	100,566,928	242,972,164	20.3	11,952,751	29.27%
346	Miscellaneous Power Plant Equipment	33,485,275	-8.5%	(2,839,101)	21,610,204	14,714,172	24.7	594,605	59.49%
348.1	Energy Storage Equipment	4,128,902	0.0%	-	3,242,796	886,107	3.0	295,369	78.54%
								$ 165,052,060	
Electric Utility Total								$ 443,814,451	

Northern States Power Company
2021 Summary of Annual Depreciation Accruals
Electric and Gas Utilities Summary
Gas Utility

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment E - Page 2 of 2

FERC Account	Account Description	1/1/2021 Beginning Plant Balance	Est. Future Net Salvage %	Est. Future Net Salvage Amount	1/1/2021 Beginning Depreciation Reserve	Net Balance	Depr Life (Yrs)	Annual Accrual	Reserve Ratio
Production									
305	Structures & Improvements	$ 2,777,523	-87.7%	$ (2,436,899)	$ 2,526,930	$ 2,687,492	9.0	$ 298,610	48.46%
311	LP Gas Equipment	13,241,932	-83.5%	(11,061,659)	11,938,576	12,365,015	9.0	1,373,891	49.12%
320	Other Equipment	1,091,608	-86.3%	(942,002)	972,139	1,061,471	9.0	117,941	47.80%
								$ 1,790,442	
Storage									
361	Structures & Improvements	$ 6,456,692	-19.2%	$ (1,239,685)	$ 6,237,141	$ 1,459,236	3.0	$ 486,412	81.04%
362	Gas Holders	8,260,593	-19.2%	(1,586,034)	8,938,728	907,899	3.0	302,633	90.78%
363	Purification Equipment	985,962	-19.2%	(189,305)	1,099,517	75,750	3.0	25,250	93.55%
363	Liquefaction Equipment	7,073,121	-19.2%	(1,358,039)	3,366,993	5,064,166	3.0	1,688,055	39.94%
363	Vaporizing Equipment	9,363,389	-19.2%	(1,797,771)	7,866,785	3,294,374	7.0	470,625	70.48%
363	Compressor Equipment	23,752,052	-19.2%	(4,560,394)	13,478,624	14,833,822	12.0	1,236,152	47.61%
363	Measuring & Regulating Equipment	73,634	-19.2%	(14,138)	75,192	12,579	3.0	4,193	85.67%
363	Other Equipment	5,433,374	-19.2%	(1,043,208)	4,959,104	1,517,477	3.0	505,826	76.57%
								$ 4,719,146	
Gas Utility Total								$ 6,509,588	

Northern States Power Company
Integrated Resource Plan Comparison

Electric Utility

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment F - Page 1 of 1

Electric Production Plant Facility	Proposed Retirement Date per Remaining Life Petition	Resource Planning/Modeling End of Life Docket No. E002/RP-19-368 Reference Plan	Rationale for Difference Between Depreciation Life and Resource Planning Period
Nuclear Monticello	2030	2040	Although the Minnesota Public Utilities Commission approved the ten year extension, the Nuclear Regulatory Commission (NRC) has not ruled on this proposal.
Other Blue Lake 1--4	2025	2023	Through the interview process, with Plant Operation Plant managers, an approximately 1.5 year extension for Blue Lake 1-4 was presented and then incorporated into this proceeding. The plant managers said this will be incorporated into the Company's next IRP.
Other Northern Wind	2047	n/a	Purchase and Sale Agreements Northern Wind & Rock Aetna Wind Repowering Projects Docket No. E002/M-20-620
Other Rock Aetna Wind	2048	n/a	Purchase and Sale Agreements Northern Wind & Rock Aetna Wind Repowering Projects Docket No. E002/M-20-620

Northern States Power Company
Historical Comparison Changes to Remaining Lives
Electric Steam Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 1 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Allen S. King											
E311	Structures & Improvements	14.5	6.0	-9.2	-9.2	EG002-D-07-251	8.5	EG002-D-19-743	0.0	0	1
E312	Boiler Plant Equipment	14.5	6.0	-9.2	-9.2	EG002-D-07-251	8.5	EG002-D-19-743	0.0	0	1
E314	Turbogenerator Units	14.5	6.0	-9.2	-9.2	EG002-D-07-251	8.5	EG002-D-19-743	0.0	0	1
E315	Accessory Electric Equipment	14.5	6.0	-9.2	-9.2	EG002-D-07-251	8.5	EG002-D-19-743	0.0	0	1
E316	Miscellaneous Power Plant Equipment	14.5	6.0	-9.2	-9.2	EG002-D-07-251	8.5	EG002-D-19-743	0.0	0	1
Red Wing											
E311	Structures & Improvements	5.0	5.0	-23.5	-23.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E312	Boiler Plant Equipment	5.0	5.0	-23.5	-23.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E314	Turbogenerator Units	5.0	5.0	-23.5	-23.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E315	Accessory Electric Equipment	5.0	5.0	-23.5	-23.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E316	Miscellaneous Power Plant Equipment	5.0	5.0	-23.5	-23.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
Sherco Unit 1											
E311	Structures & Improvements	3.0	3.0	-15.1	-15.1	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E312	Boiler Plant Equipment	3.0	3.0	-15.1	-15.1	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E314	Turbogenerator Units	3.0	3.0	-15.1	-15.1	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E315	Accessory Electric Equipment	3.0	3.0	-15.1	-15.1	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E316	Miscellaneous Power Plant Equipment	3.0	3.0	-15.1	-15.1	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
Sherco Unit 2											
E311	Structures & Improvements	-	-	-15.1	-15.1	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E312	Boiler Plant Equipment	-	-	-15.1	-15.1	EG002-D-08-189	0.0	EG002-D-19-743	0.0	0	1
E314	Turbogenerator Units	-	-	-15.1	-15.1	EG002-D-08-189	0.0	EG002-D-19-743	0.0	0	1
E315	Accessory Electric Equipment	-	-	-15.1	-15.1	EG002-D-08-189	0.0	EG002-D-19-743	0.0	0	1
E316	Miscellaneous Power Plant Equipment	-	-	-15.1	-15.1	EG002-D-08-189	0.0	EG002-D-19-743	0.0	0	1
Sherco Unit 3											
E311	Structures & Improvements	12.0	8.0	-7.9	-7.9	EG002-D-14-181	4.0	EG002-D-19-743	0.0	0	1
E312	Boiler Plant Equipment	12.0	8.0	-7.9	-7.9	EG002-D-14-181	4.0	EG002-D-19-743	0.0	0	1
E314	Turbogenerator Units	12.0	8.0	-7.9	-7.9	EG002-D-14-181	4.0	EG002-D-19-743	0.0	0	1
E315	Accessory Electric Equipment	12.0	8.0	-7.9	-7.9	EG002-D-14-181	4.0	EG002-D-19-743	0.0	0	1
E316	Miscellaneous Power Plant Equipment	12.0	8.0	-7.9	-7.9	EG002-D-14-181	4.0	EG002-D-19-743	0.0	0	1
Wilmarth											
E311	Structures & Improvements	5.0	5.0	-25.8	-25.8	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E312	Boiler Plant Equipment	5.0	5.0	-25.8	-25.8	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E314	Turbogenerator Units	5.0	5.0	-25.8	-25.8	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E315	Accessory Electric Equipment	5.0	5.0	-25.8	-25.8	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E316	Miscellaneous Power Plant Equipment	5.0	5.0	-25.8	-25.8	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1

Northern States Power Company
Historical Comparison Changes to Remaining Lives
Electric Nuclear Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 2 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Monticello											
E302	Franchises & Consents	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
E321	Structures & Improvements	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
E322	Reactor Plant Equipment	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
E323	Turbogenerator Units	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
E324	Accessory Electric Equipment	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
E325	Miscellaneous Power Plant Equipment	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
Monticello - Interim Storage Facility											
E321	Structures and Improvements	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
E322	Reactor Plant Equipment	7.8	7.8	0.0	0.0	EG002-D-07-251	-	N/A	N/A	0	N/A
Prairie Island											
E302	Franchises & Consents	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
E321	Structures & Improvements	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
E322	Reactor Plant Equipment	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
E323	Turbogenerator Units	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
E324	Accessory Electric Equipment	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
E325	Miscellaneous Power Plant Equipment	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
Prairie Island - Interim Storage Facility											
E321	Structures and Improvements	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A
E322	Reactor Plant Equipment	11.3	11.3	0.0	0.0	EG002-D-11-144	-	N/A	N/A	0	N/A

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Electric Hydro Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 3 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Hennepin Island											
E302	Franchises & Consents	11.2	11.2	0.0	0.0	EG002-D-05-288	-	EG002-D-19-743	N/A	0	1
E331	Structures & Improvements	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1
E332	Reservoirs, Dams & Waterways	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1
E333	Water Wheels, Turbines & Generators	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1
E334	Accessory Electric Equipment	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1
E335	Miscellaneous Power Plant Equipment	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1
St. Croix Falls											
E331	Structures & Improvements	5.0	5.0	-15.0	-15.0	E002/GR-15-826	-	EG002-D-19-743	0.0	0	1
E332	Reservoirs, Dams & Waterways	5.0	5.0	-15.0	-15.0	E002/GR-15-826	-	EG002-D-19-743	0.0	0	1
Upper Dam											
E332	Reservoirs, Dams & Waterways	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1
E335	Miscellaneous Power Plant Equipment	11.2	11.2	-26.7	-26.7	EG002-D-05-288	-	EG002-D-19-743	0.0	0	1

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Electric Other Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 4 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Angus C. Anson Unit 2 & 3											
E341	Structures & Improvements	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	18.0	18.0	-11.2	-11.2	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
E343	Prime Movers	18.0	18.0	-11.2	-11.2	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
E344	Generators	18.0	18.0	-11.2	-11.2	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
E345	Accessory Electric Equipment	18.0	18.0	-11.2	-11.2	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
E346	Miscellaneous Power Plant Equipment	18.0	18.0	-11.2	-11.2	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
Angus C. Anson Unit 4											
E341	Structures & Improvements	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
E344	Generators	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	22.4	22.4	-6.5	-6.5	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
Black Dog Unit 5											
E341	Structures & Improvements	35.3	35.3	-10.3	-10.3	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	9.0	9.0	-7.2	-7.2	EG002-D-02-214	0.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	9.0	9.0	-7.2	-7.2	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	9.0	9.0	-7.2	-7.2	EG002-D-02-214	0.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	9.0	9.0	-7.2	-7.2	EG002-D-02-214	0.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	9.0	9.0	-7.2	-7.2	EG002-D-02-214	0.0	EG002-D-19-743	0.0	0	1
Black Dog Unit 6											
E341	Structures & Improvements	35.3	35.3	-10.3	-10.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	35.3	35.3	-10.3	-10.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	35.3	35.3	-10.3	-10.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	35.3	35.3	-10.3	-10.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	35.3	35.3	-10.3	-10.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	35.3	35.3	-10.3	-10.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
Blazing Star I Wind (1)											
E340.1	Wind Rights	22.3	22.3	0.0	0.0	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	22.3	22.3	-11.6	-11.6	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	22.3	22.3	-11.6	-11.6	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	22.3	22.3	-11.6	-11.6	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	22.3	22.3	-11.6	-11.6	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	22.3	22.3	-11.6	-11.6	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	22.3	22.3	-11.6	-11.6	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Electric Other Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 5 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Blazing Star II Wind (2)											
E340.1	Wind Rights	23.1	23.1	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	23.1	23.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	23.1	23.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	23.1	23.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	23.1	23.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	23.1	23.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	23.1	23.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
Blue Lake Units 1 thru 4											
E341	Structures & Improvements	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	0.5	3.0	-30.6	-30.6	EG002-D-19-161	2.5	EG002-D-19-743	0.0	2	1
E343	Prime Movers	0.5	3.0	-30.6	-30.6	EG002-D-19-161	2.5	EG002-D-19-743	0.0	2	1
E344	Generators	0.5	3.0	-30.6	-30.6	EG002-D-19-161	2.5	EG002-D-19-743	0.0	2	1
E345	Accessory Electric Equipment	0.5	3.0	-30.6	-30.6	EG002-D-19-161	2.5	EG002-D-19-743	0.0	2	1
E346	Miscellaneous Power Plant Equipment	0.5	3.0	-30.6	-30.6	EG002-D-19-161	2.5	EG002-D-19-743	0.0	2	1
Blue Lake Units 7 & 8											
E341	Structures & Improvements	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	2	1
E344	Generators	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	22.4	22.4	-12.7	-12.7	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
Border Winds											
E340.1	Wind Rights	18.0	18.0	0.0	0.0	EG002-D-15-46	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	18.0	18.0	-9.5	-9.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	18.0	18.0	-9.5	-9.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	18.0	18.0	-9.5	-9.5	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	18.0	18.0	-9.5	-9.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	18.0	18.0	-9.5	-9.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	18.0	18.0	-9.5	-9.5	EG002-D-15-46	0.0	EG002-D-19-743	0.0	1	1
Community Wind North (2)											
E340.1	Wind Rights	23.0	23.0	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Electric Other Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 6 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Courtenay Wind											
E340.1	Wind Rights	18.9	18.9	0.0	0.0	EG002-D-17-147	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	18.9	18.9	-10.4	-10.4	EG002-D-17-147	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	18.9	18.9	-10.4	-10.4	EG002-D-17-147	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	18.9	18.9	-10.4	-10.4	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	18.9	18.9	-10.4	-10.4	EG002-D-17-147	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	18.9	18.9	-10.4	-10.4	EG002-D-17-147	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	18.9	18.9	-10.4	-10.4	EG002-D-17-147	0.0	EG002-D-19-743	0.0	1	1
Crowned Ridge Wind (2)											
E340.1	Wind Rights	23.0	23.0	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
Dakota Range Wind (2)											
E340.1	Wind Rights	24.1	24.1	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	24.1	24.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	24.1	24.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	24.1	24.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	24.1	24.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	24.1	24.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	24.1	24.1	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
Foxtail Wind (3)											
E340.1	Wind Rights	22.0	22.0	0.0	0.0	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	22.0	22.0	-9.1	-9.1	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	22.0	22.0	-9.1	-9.1	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	22.0	22.0	-9.1	-9.1	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	22.0	22.0	-9.1	-9.1	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	22.0	22.0	-9.1	-9.1	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	22.0	22.0	-9.1	-9.1	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
Freeborn Wind (2)											
E340.1	Wind Rights	23.4	23.4	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	23.4	23.4	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	23.4	23.4	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	23.4	23.4	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	23.4	23.4	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	23.4	23.4	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	23.4	23.4	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Electric Other Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 7 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Grand Meadow Wind											
E340.1	Wind Rights	10.9	20.9	0.0	0.0	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	0
E341	Structures & Improvements	10.9	20.9	-12.5	-12.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E342	Fuel Holders, Producers & Accessories	10.9	20.9	-12.5	-12.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	10.9	20.9	-12.5	-12.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	1	1
E344	Generators	10.9	20.9	-12.5	-12.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	10.9	20.9	-12.5	-12.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	10.9	20.9	-12.5	-12.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
High Bridge											
E341	Structures & Improvements	25.4	25.4	-4.3	-4.3	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E342	Fuel Holders, Producers & Accessories	25.4	25.4	-4.3	-4.3	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	25.4	25.4	-4.3	-4.3	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	25.4	25.4	-4.3	-4.3	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	25.4	25.4	-4.3	-4.3	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	25.4	25.4	-4.3	-4.3	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
Inver Hills											
E341	Structures & Improvements	4.0	4.0	-19.4	-19.4	EG002-D-10-173	0.0	EG002-D-19-743	0.0	0	1
E342	Fuel Holders, Producers & Accessories	4.0	4.0	-19.4	-19.4	EG002-D-10-173	0.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	4.0	4.0	-19.4	-19.4	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	4.0	4.0	-19.4	-19.4	EG002-D-10-173	0.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	4.0	4.0	-19.4	-19.4	EG002-D-10-173	0.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	4.0	4.0	-19.4	-19.4	EG002-D-10-173	0.0	EG002-D-19-743	0.0	0	1
Jeffers Wind (2)											
E340.1	Wind Rights	23.0	23.0	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	23.0	23.0	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
Lake Benton II Wind (3)											
E340.1	Wind Rights	21.9	21.9	0.0	0.0	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	21.9	21.9	-10.8	-10.8	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	21.9	21.9	-10.8	-10.8	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	21.9	21.9	-10.8	-10.8	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	21.9	21.9	-10.8	-10.8	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	21.9	21.9	-10.8	-10.8	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	21.9	21.9	-10.8	-10.8	EG002-D-19-161	0.0	EG002-D-19-743	0.0	1	1

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Electric Other Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 8 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Mower Wind (2)											
E340.1	Wind Rights	23.2	23.2	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0
E341	Structures & Improvements	23.2	23.2	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E342	Fuel Holders, Producers & Accessories	23.2	23.2	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E343	Prime Movers	23.2	23.2	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	23.2	23.2	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E345	Accessory Electric Equipment	23.2	23.2	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
E346	Miscellaneous Power Plant Equipment	23.2	23.2	-10.5	-10.5	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	1
Nobles Wind											
E340.1	Wind Rights	12.9	22.9	0.0	0.0	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	0
E341	Structures & Improvements	12.9	22.9	-8.5	-8.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E342	Fuel Holders, Producers & Accessories	12.9	22.9	-8.5	-8.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	12.9	22.9	-8.5	-8.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	1	1
E344	Generators	12.9	22.9	-8.5	-8.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	12.9	22.9	-8.5	-8.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	12.9	22.9	-8.5	-8.5	E002-M-20-620	10.0	EG002-D-19-743	0.0	0	1
Pleasant Valley Wind											
E340.1	Wind Rights	18.0	18.0	0.0	0.0	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	0
E341	Structures & Improvements	18.0	18.0	-11.7	-11.7	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E342	Fuel Holders, Producers & Accessories	18.0	18.0	-11.7	-11.7	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	18.0	18.0	-11.7	-11.7	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	18.0	18.0	-11.7	-11.7	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	18.0	18.0	-11.7	-11.7	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	18.0	18.0	-11.7	-11.7	EG002-D-15-46	0.0	EG002-D-19-743	0.0	0	1
Riverside											
E341	Structures & Improvements	26.2	26.2	-13.2	-13.2	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E342	Fuel Holders, Producers & Accessories	26.2	26.2	-13.2	-13.2	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E343	Prime Movers	26.2	26.2	-13.2	-13.2	EG002-D-18-162	0.0	EG002-D-19-743	0.0	1	1
E344	Generators	26.2	26.2	-13.2	-13.2	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E345	Accessory Electric Equipment	26.2	26.2	-13.2	-13.2	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
E346	Miscellaneous Power Plant Equipment	26.2	26.2	-13.2	-13.2	E002-GR-10-971	0.0	EG002-D-19-743	0.0	0	1
Wind-to-Battery System											
E348.1	Fuel Holders, Producers & Accessories	0.0	0.0	0.0	0.0	EG002-D-19-743	0.0	EG002-D-19-743	0.0	1	0

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Gas Production

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 9 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Maplewood											
G305	Structures & Improvements	7.0	19.0	-87.7	-87.7	EG002-D-15-46	12.0	EG002-D-19-743	0.0	0	1
G311	LP Gas Equipment	7.0	19.0	-87.7	-87.7	EG002-D-15-46	12.0	EG002-D-19-743	0.0	0	1
G320	Other Equipment	7.0	19.0	-87.7	-87.7	EG002-D-15-46	12.0	EG002-D-19-743	0.0	0	1
Sibley											
G305	Structures & Improvements	7.0	19.0	-41.1	-41.1	EG002-D-15-46	12.0	EG002-D-19-743	0.0	0	1
G311	LP Gas Equipment	7.0	19.0	-41.1	-41.1	EG002-D-15-46	12.0	EG002-D-19-743	0.0	0	1
G320	Other Equipment	7.0	19.0	-41.1	-41.1	EG002-D-15-46	12.0	EG002-D-19-743	0.0	0	1

Northern States Power Company
Historical Comparison of Changes to Remaining Lives
Gas Storage

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment G - Page 10 of 10

Account	Description	Current Approved Remaining Life 01/01/21 (Yrs)	Proposed Remaining Life 01/01/23 (Yrs)	Current Approved Net Salvage 01/01/21 (%)	Proposed Net Salvage 01/01/23 (%)	Latest Life Change (Docket #)	Life Change (Yrs)	Latest Net Salvage Change (Docket #)	Net Salvage Change (%)	Number of Life Changes in the Last Five Years	Number of Net Salvage Changes in the Last Five Years
Wescott											
G361	Structures & Improvements	1.0	19.0	-19.6	-19.6	EG002-D-14-181	18.0	EG002-D-19-743	0.0	0	1
G362	Gas Holders	1.0	19.0	-19.6	-19.6	EG002-D-14-181	18.0	EG002-D-19-743	0.0	0	1
G363	Purification Equipment	1.0	19.0	-19.6	-19.6	EG002-D-14-181	18.0	EG002-D-19-743	0.0	0	1
G363.1	Liquefaction Equipment	1.0	19.0	-19.6	-19.6	EG002-D-14-181	18.0	EG002-D-19-743	0.0	0	1
G363.2	Vaporizing Equipment	5.0	19.0	-19.6	-19.6	EG002-D-98-221	14.0	EG002-D-19-743	0.0	0	1
G363.3	Compressor Equipment	10.0	19.0	-19.6	-19.6	EG002-D-13-1158	9.0	EG002-D-19-743	0.0	0	1
G363.4	Measuring & Regulating Equipment	1.0	19.0	-19.6	-19.6	EG002-D-14-181	18.0	EG002-D-19-743	0.0	0	1
G363.5	Other Equipment	1.0	19.0	-19.6	-19.6	EG002-D-14-181	18.0	EG002-D-19-743	0.0	0	1

Northern States Power Company
Removal Estimate by Year

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment H - Page 1 of 1

Electric Utility

Plant	Item		2021		2022		2023		Est Comp % 12/31/2021
Black Dog	COR Beginning Reserve		$ 4,783,797		$ 18,113,797		$ 20,323,797		
Black Dog	COR Expense		$ 2,210,000		$ 2,210,000		$ 2,210,000		
Black Dog	Adjustments/Transfers		$ 11,120,000	(1)	$ -		$ -		
Black Dog	Cost of Removal		$ -		$ -		$ (18,321,965)	(3)	
Black Dog	COR Ending Reserve	(a)	$ 18,113,797		$ 20,323,797		$ 4,211,832		
Black Dog	RWIP Beginning Balance		$ 17,019,818		$ 17,899,214		$ 18,083,514		
Black Dog	RWIP Expenditures		$ 879,397		$ 184,300		$ 237,804		
Black Dog	RWIP Closing		$ -		$ -		$ (18,321,318)		
Black Dog	RWIP Ending Balance	(b)	$ 17,899,214		$ 18,083,514		$ -		
Black Dog	Net COR Recovery	(a - b)	$ 214,582		$ 2,240,283		$ 4,211,832		98%

Plant	Item		2021		2022		2023		
Granite City	COR Beginning Reserve		$ 4,420,358		$ 4,168,385		$ 3,812,619		
Granite City	COR Expense		$ -		$ -		$ -		
Granite City	Adjustments/Transfers		$ -		$ 249,488	(2)	$ -		
Granite City	Cost of Removal		$ (251,973)		$ (605,253)		$ -		
Granite City	COR Ending Reserve	(a)	$ 4,168,385		$ 3,812,619		$ 3,812,619		
Granite City	RWIP Beginning Balance		$ 253,240		$ 330,765		$ -		
Granite City	RWIP Expenditures		$ 329,499		$ 25,000		$ -		
Granite City	RWIP Closing		$ (251,973)		$ (355,765)		$ -		
Granite City	RWIP Ending Balance	(b)	$ 330,765		$ -		$ -		
Granite City	Net COR Recovery	(a - b)	$ 3,837,619		$ 3,812,619		$ 3,812,619		93%

Plant	Item		2021		2022		2023		
Key City	COR Beginning Reserve		$ 4,093,558		$ 3,730,263		$ 3,387,404		
Key City	COR Expense		$ -		$ -		$ -		
Key City	Adjustments/Transfers		$ 11,404		$ 193,680	(2)	$ -		
Key City	Cost of Removal		$ (374,700)		$ (536,539)		$ -		
Key City	COR Ending Reserve	(a)	$ 3,730,263		$ 3,387,404		$ 3,387,404		
Key City	RWIP Beginning Balance		$ 364,505		$ 343,377		$ -		
Key City	RWIP Expenditures		$ 342,167		$ (518)		$ -		
Key City	RWIP Closing		$ (363,296)		$ (342,859)		$ -		
Key City	RWIP Ending Balance	(b)	$ 343,377		$ -		$ -		
Key City	Net COR Recovery	(a - b)	$ 3,386,886		$ 3,387,404		$ 3,387,404		100%

Plant	Item		2021		2022		2023		
MN Valley	COR Beginning Reserve		$ 17,441,751		$ 7,141,751		$ 7,141,751		
MN Valley	COR Expense		$ -		$ -		$ -		
MN Valley	Adjustments/Transfers		$ (10,300,000)	(1)	$ -		$ -		
MN Valley	Cost of Removal		$ -		$ -		$ (9,461,674)	(3)	
MN Valley	COR Ending Reserve	(a)	$ 7,141,751		$ 7,141,751		$ (2,319,923)		
MN Valley	RWIP Beginning Balance		$ 14,601		$ 1,102,465		$ 9,461,674		
MN Valley	RWIP Expenditures		$ 1,087,864		$ 8,359,209		$ -		
MN Valley	RWIP Closing		$ -		$ -		$ (9,461,674)		
MN Valley	RWIP Ending Balance	(b)	$ 1,102,465		$ 9,461,674		$ -		
MN Valley	Net COR Recovery	(a - b)	$ 6,039,287		$ (2,319,923)		$ (2,319,923)		12%

(1) Reserve reallocation between Black Dog/Minnesota Valley occurred in 2021 and is reflected in the Adjustments/Transfers Item
(2) Since recovery of the life portion of the assets is complete, any salvage value is reclassed to the cost of removal reserve
(3) Forecasted removal costs include contingencies and net of any estimated proceeds

Northern States Power Company
Comparison of Present to Proposed Net Salvage Rates

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment I - Page 1 of 7

Electric Steam Production

	FERC Account	Plant Balance 1/1/2022 (1)	Present: Net Salv % (2)	Present: Estimated Net Salvage in Reserve at End of Life (3)	Proposed: Net Salv % (4)	Proposed: Estimated Net Salvage in Reserve at End of Life (5)	Proposed Less Present (6)
Allen S. King							
	E311	$ 39,721,551	-9.2	$ 3,654,383	-9.2	$ 3,654,383	$ -
	E312	$ 525,951,646	-9.2	$ 48,387,551	-9.2	$ 48,387,551	$ -
	E314	$ 94,307,445	-9.2	$ 8,676,285	-9.2	$ 8,676,285	$ -
	E315	$ 46,921,220	-9.2	$ 4,316,752	-9.2	$ 4,316,752	$ -
	E316	$ 7,979,927	-9.2	$ 734,153	-9.2	$ 734,153	$ -
		$ 714,881,790		$ 65,769,125		$ 65,769,125	$ -
				From 2020 Dismantling Study for King	-9.2%	$ 65,769,125	
Red Wing							
	E311	$ 12,856,986	-23.5	$ 3,021,392	-23.5	$ 3,021,392	$ -
	E312	$ 47,840,342	-23.5	$ 11,242,480	-23.5	$ 11,242,480	$ -
	E314	$ 6,111,636	-23.5	$ 1,436,234	-23.5	$ 1,436,234	$ -
	E315	$ 1,905,550	-23.5	$ 447,804	-23.5	$ 447,804	$ -
	E316	$ 1,484,962	-23.5	$ 348,966	-23.5	$ 348,966	$ -
		$ 70,199,477		$ 16,496,877		$ 16,496,877	$ -
				From 2020 Dismantling Study for Red Wing	-23.5%	$ 16,496,877	
Sherco Units 1 & 2							
	E311	$ 96,365,770	-15.1	$ 14,551,231	-15.1	$ 14,551,231	$ -
	E312	$ 436,999,604	-15.1	$ 65,986,940	-15.1	$ 65,986,940	$ -
	E314	$ 124,993,581	-15.1	$ 18,874,031	-15.1	$ 18,874,031	$ -
	E315	$ 54,081,011	-15.1	$ 8,166,233	-15.1	$ 8,166,233	$ -
	E316	$ 12,378,693	-15.1	$ 1,869,183	-15.1	$ 1,869,183	$ -
		$ 724,818,659		$ 109,447,617		$ 109,447,617	$ -
				From 2020 Dismantling Study for Sherco 1 & 2	-15.1%	$ 109,447,617	
Sherco Unit 3 (*)							
	E311	$ 133,482,187	-7.9	$ 10,545,093	-7.9	$ 10,545,093	$ -
	E312	$ 457,428,065	-7.9	$ 36,136,817	-7.9	$ 36,136,817	$ -
	E314	$ 90,332,472	-7.9	$ 7,136,265	-7.9	$ 7,136,265	$ -
	E315	$ 83,085,559	-7.9	$ 6,563,759	-7.9	$ 6,563,759	$ -
	E316	$ 31,193,847	-7.9	$ 2,464,314	-7.9	$ 2,464,314	$ -
		$ 795,522,130		$ 62,846,248		$ 62,846,248	$ -
				From 2020 Dismantling Study for Sherco 3	-7.9%	$ 62,846,248	
Wilmarth							
	E311	$ 11,645,698	-25.8	$ 3,004,590	-25.8	$ 3,004,590	$ -
	E312	$ 44,393,918	-25.8	$ 11,453,631	-25.8	$ 11,453,631	$ -
	E314	$ 6,175,415	-25.8	$ 1,593,257	-25.8	$ 1,593,257	$ -
	E315	$ 1,551,512	-25.8	$ 400,290	-25.8	$ 400,290	$ -
	E316	$ 821,824	-25.8	$ 212,031	-25.8	$ 212,031	$ -
		$ 64,588,367		$ 16,663,799		$ 16,663,799	$ -
				From 2020 Dismantling Study for Wilmarth	-25.8%	$ 16,663,799	
Total Steam Production		$ 2,370,010,422		$ 271,223,666		$ 271,223,666	$ -

* Amounts reported in this section are for the entire unit, not just Xcel Energy's share.

Northern States Power Company
Comparison of Present to Proposed Net Salvage Rates

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment I - Page 2 of 7

Electric Hydro Production

	FERC Account	Plant Balance 1/1/2022	Present Net Salv %	Present Estimated Net Salvage in Reserve at End of Life	Proposed Net Salv %	Proposed Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Hennepin Island							
	E302	$ 2,857,039	0.0	$ -	0.0	$ -	$ -
	E331	$ 1,429,599	-26.7	$ 381,703	-26.7	$ 381,703	$ -
	E332	$ 4,398,484	-26.7	$ 1,174,395	-26.7	$ 1,174,395	$ -
	E333	$ 10,156,575	-26.7	$ 2,711,806	-26.7	$ 2,711,806	$ -
	E334	$ 3,279,241	-26.7	$ 875,557	-26.7	$ 875,557	$ -
	E335	$ 37,779	-26.7	$ 10,087	-26.7	$ 10,087	$ -
	E336	$ 152,075	-26.7	$ 40,604	-26.7	$ 40,604	$ -
		$ 22,310,791		$ 5,194,152		$ 5,194,152	$ -
		From 2020 Dismantling Study for Hennepin Island			-26.7% Note 1	$ 5,194,152	
St. Croix Falls							
	E331	$ 37,924	-15	$ 5,689	-15.0	$ 5,689	$ -
	E332	$ 2,196,276	-15	$ 329,441	-15.0	$ 329,441	$ -
		$ 2,234,201		$ 335,130		$ 335,130	$ -
				St. Croix Falls Note 2	-15.0%	$ 335,130	
Upper Dam							
	E332	$ 4,491,476	-26.7	$ 1,199,224	-26.7	$ 1,199,224	$ -
	E335	$ 23,046	-26.7	$ 6,153	-26.7	$ 6,153	$ -
		$ 4,514,522		$ 1,205,377		$ 1,205,377	$ -
		From 2020 Dismantling Study for Upper Dam			-26.7%	$ 1,205,377 Note 2	
Total Hydro Production		$ 29,059,513		$ 6,734,659		$ 6,734,659	$ -

Note 1: To calculate the proposed net salvage percent, FERC 302 Licenses was excluded from the plant balance as removal costs do not apply to this account.
Note 2: St. Croix Falls is mainly located in Wisconsin but a portion of the facility is in Minnesota. The balances above represent the Minnesota assets included on NSP-Minnesota's records. This facility was not included in the TLG Dismantling Study. Therefore, we are using the net salvage rate for FERC 332 approved by the Public Service Commission of Wisconsin.

Northern States Power Company
Comparison of Present to Proposed Net Salvage Rates

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment I - Page 3 of 7

Electric Other Production

	FERC Account	Plant Balance 1/1/2022	Present Net Salv %	Present Estimated Net Salvage in Reserve at End of Life	Proposed Net Salv %	Proposed Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Angus C. Anson Units 2 & 3							
	E341	$ -	-11.2	$ -	-11.2	$ -	$ -
	E342	$ 1,070,423	-11.2	$ 119,887	-11.2	$ 119,887	$ -
	E344	$ 77,661,605	-11.2	$ 8,698,100	-11.2	$ 8,698,100	$ -
	E345	$ 4,876,179	-11.2	$ 546,132	-11.2	$ 546,132	$ -
	E346	$ 2,631,260	-11.2	$ 294,701	-11.2	$ 294,701	$ -
		$ 86,239,468		$ 9,658,820		$ 9,658,820	$ -
From 2020 Dismantling Study for Angus Anson Units 2 & 3					-11.2%	$ 9,658,820	
Angus C. Anson Unit 4							
	E341	$ 8,235,254	-6.5	$ 535,292	-6.5	$ 535,292	$ -
	E342	$ 13,506	-6.5	$ 878	-6.5	$ 878	$ -
	E344	$ 33,793,801	-6.5	$ 2,196,597	-6.5	$ 2,196,597	$ -
	E345	$ 4,930,962	-6.5	$ 320,512	-6.5	$ 320,512	$ -
	E346	$ 20,727	-6.5	$ 1,347	-6.5	$ 1,347	$ -
		$ 46,994,250		$ 3,054,626		$ 3,054,626	$ -
From 2020 Dismantling Study for Angus Anson 4					-6.5%	$ 3,054,626	
Black Dog Unit 5							
	E342	$ 12,539,031	-7.2	$ 902,810	-7.2	$ 902,810	$ -
	E343	$ 24,220,121	-7.2	$ 1,743,849	-7.2	$ 1,743,849	$ -
	E344	$ 125,367,218	-7.2	$ 9,026,440	-7.2	$ 9,026,440	$ -
	E345	$ 28,111,443	-7.2	$ 2,024,024	-7.2	$ 2,024,024	$ -
	E346	$ 5,657,756	-7.2	$ 407,358	-7.2	$ 407,358	$ -
		$ 195,895,570		$ 14,104,481		$ 14,104,481	$ -
From 2020 Dismantling Study for Black Dog Unit 5					-7.2%	$ 14,104,481	
						Note 1	
Black Dog Unit 6							
	E341	$ 43,411,128	-10.3	$ 4,471,346	-10.3	$ 4,471,346	$ -
	E341	$ 13,825,936	-10.3	$ 1,424,071	-10.3	$ 1,424,071	$ -
	E342	$ 9,512,175	-10.3	$ 979,754	-10.3	$ 979,754	$ -
	E344	$ 62,375,841	-10.3	$ 6,424,712	-10.3	$ 6,424,712	$ -
	E345	$ 11,141,445	-10.3	$ 1,147,569	-10.3	$ 1,147,569	$ -
	E346	$ 5,817,664	-10.3	$ 599,219	-10.3	$ 599,219	$ -
		$ 146,084,190		$ 15,046,672		$ 15,046,672	$ -
From 2020 Dismantling Study for Black Dog Unit 6					-10.3%	$ 15,046,672	
						Note 1	
Blazing Star I							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 22,712,370	-11.6	$ 2,634,635	-11.6	$ 2,634,635	$ -
	E342	$ -	-11.6	$ -	-11.6	$ -	$ -
	E344	$ 274,310,899	-11.6	$ 31,820,064	-11.6	$ 31,820,064	$ -
	E345	$ 10,359,276	-11.6	$ 1,201,676	-11.6	$ 1,201,676	$ -
	E346	$ -	-11.6	$ -	-11.6	$ -	$ -
		$ 307,382,545		$ 35,656,375		$ 35,656,375	$ -
From 2020 Dismantling Study for Blazing Star I					-11.6%	$ 35,656,375	
					Note 2		
Blazing Star II							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 26,563,875	-10.5	$ 2,789,207	-10.5	$ 2,789,207	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ 305,321,580	-10.5	$ 32,058,766	-10.5	$ 32,058,766	$ -
	E345	$ 4,959,722	-10.5	$ 520,771	-10.5	$ 520,771	$ -
	E346	$ 1,887,590	-10.5	$ 198,197	-10.5	$ 198,197	$ -
		$ 338,732,767		$ 35,566,941		$ 35,566,941	$ -
From 2020 Dismantling Study for Blazing Star II					-10.5%	$ 35,566,941	
					Note 2		
Blue Lake Units 1 thru 4							
	E341	$ -	-30.6	$ -	-30.6	$ -	$ -
	E342	$ 1,340,395	-30.6	$ 410,161	-30.6	$ 410,161	$ -
	E344	$ 21,359,097	-30.6	$ 6,535,884	-30.6	$ 6,535,884	$ -
	E345	$ 2,726,341	-30.6	$ 834,260	-30.6	$ 834,260	$ -
	E346	$ 886,743	-30.6	$ 271,343	-30.6	$ 271,343	$ -
		$ 26,312,577		$ 8,051,649		$ 8,051,649	$ -
From 2020 Dismantling Study for Blue Lake Units 1 thru 4					-30.6%	$ 8,051,649	

Northern States Power Company
Comparison of Present to Proposed Net Salvage Rates

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment I - Page 4 of 7

Electric Other Production

	FERC Account	Plant Balance 1/1/2022	Present: Net Salv %	Present: Estimated Net Salvage in Reserve at End of Life	Proposed: Net Salv %	Proposed: Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Blue Lake Units 7 & 8							
	E341	$ 1,703,454	-12.7	$ 216,339	-12.7	$ 216,339	$ -
	E342	$ 47,986	-12.7	$ 6,094	-12.7	$ 6,094	$ -
	E344	$ 69,105,883	-12.7	$ 8,776,447	-12.7	$ 8,776,447	$ -
	E345	$ 8,007,188	-12.7	$ 1,016,913	-12.7	$ 1,016,913	$ -
	E346	$ 32,958	-12.7	$ 4,186	-12.7	$ 4,186	$ -
		$ 78,897,469		$ 10,019,979		$ 10,019,979	$ -
From 2020 Dismantling Study for Blue Lake 7 & 8					-12.7%	$ 10,019,979	
Border Winds							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 22,226,432	-9.5	$ 2,111,511	-9.5	$ 2,111,511	$ -
	E342	$ -	-9.5	$ -	-9.5	$ -	$ -
	E344	$ 207,682,752	-9.5	$ 19,729,861	-9.5	$ 19,729,861	$ -
	E345	$ 34,794,649	-9.5	$ 3,305,492	-9.5	$ 3,305,492	$ -
	E346	$ 228,153	-9.5	$ 21,675	-9.5	$ 21,675	$ -
		$ 264,931,986		$ 25,168,539		$ 25,168,539	$ -
From 2020 Dismantling Study for Border Winds					-9.5% Notes 2 & 3	$ 25,168,539	
Community North Wind							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 2,710,368	-10.5	$ 284,589	-10.5	$ 284,589	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ 26,412,178	-10.5	$ 2,773,279	-10.5	$ 2,773,279	$ -
	E345	$ 1,310,167	-10.5	$ 137,568	-10.5	$ 137,568	$ -
	E346	$ 81,604	-10.5	$ 8,568	-10.5	$ 8,568	$ -
		$ 30,514,318		$ 3,204,003		$ 3,204,003	$ -
From 2020 Dismantling Study for Community North Winds					-10.5% Note 2	$ 3,204,003	
Courtenay Wind							
	E340	$ 2,085,661	0.0	$ -	0.0	$ -	$ -
	E341	$ 7,621,664	-10.4	$ 792,653	-10.4	$ 792,653	$ -
	E342	$ -	-10.4	$ -	-10.4	$ -	$ -
	E344	$ 264,043,707	-10.4	$ 27,460,546	-10.4	$ 27,460,546	$ -
	E345	$ 10,040,328	-10.4	$ 1,044,194	-10.4	$ 1,044,194	$ -
	E346	$ 36,482	-10.4	$ 3,794	-10.4	$ 3,794	$ -
		$ 283,827,841		$ 29,301,187		$ 29,301,187	$ -
From 2020 Dismantling Study for Courtaney					-10.4% Notes 2 & 3	$ 29,301,187	
Crowned Ridge Wind							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 20,722,944	-10.5	$ 2,175,909	-10.5	$ 2,175,909	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ 276,861,066	-10.5	$ 29,070,412	-10.5	$ 29,070,412	$ -
	E345	$ 11,464,510	-10.5	$ 1,203,774	-10.5	$ 1,203,774	$ -
	E346	$ 194,943	-10.5	$ 20,469	-10.5	$ 20,469	$ -
		$ 309,243,462		$ 32,470,563		$ 32,470,563	$ -
From 2020 Dismantling Study for Crowned Ridge Wind					-10.5% Note 2	$ 32,470,563	
Dakota Range Wind							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ -	-10.5	$ -	-10.5	$ -	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ -	-10.5	$ -	-10.5	$ -	$ -
	E345	$ -	-10.5	$ -	-10.5	$ -	$ -
	E346	$ -	-10.5	$ -	-10.5	$ -	$ -
		$ -		$ -		$ -	$ -
From 2020 Dismantling Study for Dakota Range Wind					-10.5% Note 2	$ -	
Foxtail Wind							
	E340	$ 177,364	0.0	$ -	0.0	$ -	$ -
	E341	$ 32,726,023	-9.1	$ 2,978,068	-9.1	$ 2,978,068	$ -
	E344	$ 204,085,404	-9.1	$ 18,571,772	-9.1	$ 18,571,772	$ -
		$ 236,988,791		$ 21,549,840		$ 21,549,840	$ -
From 2020 Dismantling Study for Foxtail					-9.1% Note 3	$ 21,549,840	

Electric Other Production

	FERC Account	Plant Balance 1/1/2022	Present: Net Salv %	Present: Estimated Net Salvage in Reserve at End of Life	Proposed: Net Salv %	Proposed: Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Freeborn Wind							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 63,028,255	-10.5	$ 6,617,967	-10.5	$ 6,617,967	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ 236,613,706	-10.5	$ 24,844,439	-10.5	$ 24,844,439	$ -
	E345	$ 685,711	-10.5	$ 72,000	-10.5	$ 72,000	$ -
	E346	$ 20,488,106	-10.5	$ 2,151,251	-10.5	$ 2,151,251	$ -
		$ 320,815,777		$ 33,685,657		$ 33,685,657	$ -
		From 2020 Dismantling Study for Freeborn Wind			-10.5% Note 2	$ 33,685,657	
Grand Meadow Wind							
	E340	$ 10,672,452	0.0	$ -	0.0	$ -	$ -
	E341	$ 5,589,344	-12.5	$ 698,668	-12.5	$ 698,668	$ -
	E342	$ -	-12.5	$ -	-12.5	$ -	$ -
	E344	$ 183,695,056	-12.5	$ 22,961,882	-12.5	$ 22,961,882	$ -
	E345	$ 12,073,394	-12.5	$ 1,509,174	-12.5	$ 1,509,174	$ -
	E346	$ 209,119	-12.5	$ 26,140	-12.5	$ 26,140	$ -
		$ 212,239,365		$ 25,195,864		$ 25,195,864	$ -
		From 2020 Dismantling Study for Grand Meadow			-12.5% Note 2	$ 25,195,864	
High Bridge							
	E341	$ 71,147,957	-4.3	$ 3,059,362	-4.3	$ 3,059,362	$ -
	E342	$ 753,399	-4.3	$ 32,396	-4.3	$ 32,396	$ -
	E343	$ 67,960,213	-4.3	$ 2,922,289	-4.3	$ 2,922,289	$ -
	E344	$ 210,175,920	-4.3	$ 9,037,565	-4.3	$ 9,037,565	$ -
	E345	$ 52,014,326	-4.3	$ 2,236,616	-4.3	$ 2,236,616	$ -
	E346	$ 7,144,763	-4.3	$ 307,225	-4.3	$ 307,225	$ -
		$ 409,196,577		$ 17,595,453		$ 17,595,453	$ -
		From 2020 Dismantling Study for High Bridge			-4.3%	$ 17,595,453	
Inver Hills							
	E341	$ 1,617,415	-19.4	$ 313,778	-19.4	$ 313,778	$ -
	E342	$ 599,614	-19.4	$ 116,325	-19.4	$ 116,325	$ -
	E344	$ 50,980,595	-19.4	$ 9,890,235	-19.4	$ 9,890,235	$ -
	E345	$ 4,309,713	-19.4	$ 836,084	-19.4	$ 836,084	$ -
	E346	$ 617,845	-19.4	$ 119,862	-19.4	$ 119,862	$ -
		$ 58,125,181		$ 11,276,285		$ 11,276,285	$ -
		From 2020 Dismantling Study for Inver Hills			-19.4%	$ 11,276,285	
Jeffers Wind							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 3,706,351	-10.5	$ 389,167	-10.5	$ 389,167	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ 38,324,900	-10.5	$ 4,024,114	-10.5	$ 4,024,114	$ -
	E345	$ 507,681	-10.5	$ 53,307	-10.5	$ 53,307	$ -
	E346	$ 190,058	-10.5	$ 19,956	-10.5	$ 19,956	$ -
		$ 42,728,989		$ 4,486,544		$ 4,486,544	$ -
		From 2020Dismantling Study for Jeffers Wind			-10.5% Note 2	$ 4,486,544	

Northern States Power Company
Comparison of Present to Proposed Net Salvage Rates

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment I - Page 6 of 7

Electric Other Production

	FERC Account	Plant Balance 1/1/2022	Present Net Salv %	Present Estimated Net Salvage in Reserve at End of Life	Proposed Net Salv %	Proposed Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Lake Benton II Wind							
	E340	$ -	0.0	$ -	0.0	$ -	$ -
	E341	$ 33,079,253	-10.8	$ 3,572,559	-10.8	$ 3,572,559	$ -
	E344	$ 116,607,126	-10.8	$ 12,593,570	-10.8	$ 12,593,570	$ -
	E345	$ 11,207,318	-10.8	$ 1,210,390	-10.8	$ 1,210,390	$ -
		$ 160,893,697		$ 17,376,519		$ 17,376,519	$ -
			From 2020 Dismantling Study for Lake Benton II		-10.8% Note 2	$ 17,376,519	
Mower Wind							
	E340	$ 627,881	0.0	$ -	0.0	$ -	$ -
	E341	$ 11,130,151	-10.5	$ 1,168,666	-10.5	$ 1,168,666	$ -
	E342	$ -	-10.5	$ -	-10.5	$ -	$ -
	E344	$ 194,001,860	-10.5	$ 20,370,195	-10.5	$ 20,370,195	$ -
	E345	$ 2,275,151	-10.5	$ 238,891	-10.5	$ 238,891	$ -
	E346	$ 765,024	-10.5	$ 80,328	-10.5	$ 80,328	$ -
		$ 208,800,067		$ 21,858,080		$ 21,858,080	$ -
			From 2020 Dismantling Study for Mower Wind		-10.5% Note 2	$ 21,858,080	
Nobles Wind							
	E340	$ 3,884,834	0.0	$ -	0.0	$ -	$ -
	E341	$ 13,536,911	-8.5	$ 1,150,637	-8.5	$ 1,150,637	$ -
	E344	$ 470,979,873	-8.5	$ 40,033,289	-8.5	$ 40,033,289	$ -
	E345	$ 29,969,729	-8.5	$ 2,547,427	-8.5	$ 2,547,427	$ -
	E346	$ 627,971	-8.5	$ 53,378	-8.5	$ 53,378	$ -
		$ 518,999,319		$ 43,784,731		$ 43,784,731	$ -
			From 2020 Dismantling Study for Nobles		-8.5% Note 2	$ 43,784,731	
Pleasant Valley Wind							
	E341	$ 25,806,960	-11.7	$ 3,019,414	-11.7	$ 3,019,414	$ -
	E344	$ 263,869,298	-11.7	$ 30,872,708	-11.7	$ 30,872,708	$ -
	E345	$ 42,507,679	-11.7	$ 4,973,398	-11.7	$ 4,973,398	$ -
	E346	$ 292,092	-11.7	$ 34,175	-11.7	$ 34,175	$ -
		$ 332,476,029		$ 38,899,695		$ 38,899,695	$ -
			From 2020 Dismantling Study for Pleasant Valley		-11.7%	$ 38,899,695	
Riverside							
	E341	$ 52,858,845	-13.2	$ 6,977,368	-13.2	$ 6,977,368	$ -
	E342	$ 2,059,988	-13.2	$ 271,918	-13.2	$ 271,918	$ -
	E343	$ 51,482,617	-13.2	$ 6,795,705	-13.2	$ 6,795,705	$ -
	E344	$ 176,489,317	-13.2	$ 23,296,590	-13.2	$ 23,296,590	$ -
	E345	$ 40,495,707	-13.2	$ 5,345,433	-13.2	$ 5,345,433	$ -
	E346	$ 11,142,086	-13.2	$ 1,470,755	-13.2	$ 1,470,755	$ -
		$ 334,528,560		$ 44,157,770		$ 44,157,770	$ -
			From 2020 Dismantling Study for Riverside		-13.2%	$ 44,157,770	
Total Other Production		$ 4,950,848,793		$ 501,170,272		$ 501,170,272	$ -

Note 1: As TLG's estimate was for the entire Black Dog site including the former steam units, the Company performed analysis and calculations to determine the portions attributable to the steam demolition versus the future removal for the other production units and common/shared facilities.

Note 2: To calculate the proposed net salvage percent, FERC 340 Wind Rights was excluded from the plant balance as removal costs do not apply to this account.

Note 3: Border, Courtenay, and Foxtail wind farms are located in North Dakota which only requires removal to a depth of 48". Thus, the 48" removal scenario was used to calculate the net salvage rate.

Northern States Power Company
Comparison of Present to Proposed Net Salvage Rates

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment I - Page 7 of 7

Gas Production and Storage

	FERC Account	Plant Balance 1/1/2022	Present: Net Salv %	Present: Estimated Net Salvage in Reserve at End of Life	Proposed: Net Salv %	Proposed: Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Maplewood							
	G305	$ 1,670,673	-87.7	$ 1,465,180	-87.7	$ 1,465,180	$ -
	G311	$ 3,766,755	-87.7	$ 3,303,444	-87.7	$ 3,303,444	$ -
	G320	$ 455,629	-87.7	$ 399,587	-87.7	$ 399,587	$ -
		$ 5,893,057		$ 5,168,211		$ 5,168,211	$ -
				From 2020 Dismantling Study for Maplewood	-87.7%	$ 5,168,211	
Sibley							
	G305	$ 1,166,477	-41.1	$ 479,422	-41.1	$ 479,422	$ -
	G311	$ 12,089,035	-41.1	$ 4,968,593	-41.1	$ 4,968,593	$ -
	G320	$ 617,868	-41.1	$ 253,944	-41.1	$ 253,944	$ -
		$ 13,873,380		$ 5,701,959		$ 5,701,959	$ -
				From 2020 Dismantling Study for Sibley	-41.1%	$ 5,701,959	
Wescott							
	G361	$ 6,500,975	-19.6	$ 1,274,191	-19.6	$ 1,274,191	$ -
	G362	$ 8,260,593	-19.6	$ 1,619,076	-19.6	$ 1,619,076	$ -
	G363	$ 8,004,034	-19.6	$ 1,568,791	-19.6	$ 1,568,791	$ -
	G363.1	$ 8,083,589	-19.6	$ 1,584,383	-19.6	$ 1,584,383	$ -
	G363.2	$ 9,741,410	-19.6	$ 1,909,316	-19.6	$ 1,909,316	$ -
	G363.3	$ 24,028,293	-19.6	$ 4,709,545	-19.6	$ 4,709,545	$ -
	G363.4	$ 73,634	-19.6	$ 14,432	-19.6	$ 14,432	$ -
	G363.5	$ 5,468,258	-19.6	$ 1,071,779	-19.6	$ 1,071,779	$ -
		$ 70,160,786		$ 13,751,514		$ 13,751,514	$ -
				From 2020 Dismantling Study for Wescott	-19.6%	$ 13,751,514	
Total Gas Production and Storage		$ 89,927,223		$ 24,621,684		$ 24,621,684	$ -

Northern States Power Company
Total Life of Plants

Docket No. E,G002/D-22-299
2022 Electric Gas Production Gas Storage ARL
Attachment K - Page 1 of 1

Function	Plant	In-service date	Approved retirement date (1)	As of 1/1/2022 Current Age	As of 1/1/2022 Years to retirement	Total Service Life	Notes
Steam Production	Allen S. King	1968	2037	53	16	69	
Steam Production	Red Wing	1949	2027	72	6	78	(2)
Steam Production	Sherco Unit 1	1976	2025	45	4	49	
Steam Production	Sherco Unit 2	1977	2022	44	1	45	
Steam Production	Sherco Unit 3	1987	2034	34	13	47	
Steam Production	Wilmarth Unit 1	1948	2027	73	6	79	(3)
Steam Production	Wilmarth Unit 2	1951	2027	70	6	76	(3)
Nuclear Production	Monticello	1971	2030	50	9	59	(4)
Nuclear Production	Prairie Island Unit 1	1973	2034	48	13	61	
Nuclear Production	Prairie Island Unit 2	1974	2034	47	13	60	
Hydro Production	Hennepin Island	1882	2034	139	13	152	
Hydro Production	St. Croix Falls	1905	2027	116	6	122	
Hydro Production	Upper Dam	2001	2034	20	13	33	
Other Production	Angus Anson Unit 2&3	1994	2040	27	19	46	
Other Production	Angus Anson Unit 4	2005	2045	16	24	40	
Other Production	Black Dog Unit 5	2002	2031	19	10	29	
Other Production	Black Dog Unit 6	2018	2058	3	37	40	
Other Production	Blazing Star 1 Wind	2020	2045	1	24	25	
Other Production	Blazing Star 2 Wind	2021	2046	0	25	25	
Other Production	Blue Lake Units 1-4	1974	2023	47	2	49	
Other Production	Blue Lake Unit 7&8	2005	2045	16	24	40	
Other Production	Border Wind	2015	2040	6	19	25	
Other Production	Community Wind North	2020	2045	1	24	25	
Other Production	Courtenay Wind	2016	2041	5	20	25	
Other Production	Crowned Ridge Wind	2020	2045	1	24	25	
Other Production	Dakota Range Wind	2022	2047	$\boxed{-1}$	26	25	
Other Production	Foxtail Wind	2019	2044	2	23	25	
Other Production	Freeborn Wind	2021	2046	0	25	25	
Other Production	Grand Meadow Wind	2008	2033	13	12	25	
Other Production	High Bridge	2008	2048	13	27	40	
Other Production	Inver Hills	1972	2026	49	5	54	
Other Production	Jeffers Wind	2020	2045	1	24	25	
Other Production	Lake Benton II Wind	2019	2044	2	23	25	
Other Production	Mower Wind	2021	2046	0	25	25	
Other Production	Nobles Wind Farm	2010	2035	11	14	25	
Other Production	Pleasant Valley Wind	2015	2040	6	19	25	
Other Production	Riverside	2009	2049	12	28	40	
Gas Production	Maplewood	1957	2029	64	8	72	
Gas Production	Sibley	1953	2029	68	8	76	
Gas Storage	Wescott	1972	2023	49	2	51	(5)

(1) As approved in Minnesota Public Utilities Commission Docket No. E,G002/D-19-763.
(2) Units converted to burn refuse-derived fuels in 1986.
(3) Units converted to burn refuse-derived fuels in 1987.
(4) Monticello received its 40 year operating license in 1970 but did not start commerical operation until 1971.
(5) Most of the plant is currently approved to retire in 2023. FERC Account 363.2 Vaporizing Equipment is currently approved to retire in 2027 and FERC Account 363.3 Compressor Equipment is currently approved to retire in 2032.

CERTIFICATE OF SERVICE

I, Mustafa Adam, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. E,G002/D-22-299

Dated this 8th day of September 2022

/s/

____

Mustafa Adam

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_22-299_D-22-299
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_22-299_D-22-299
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_22-299_D-22-299
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_22-299_D-22-299
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_22-299_D-22-299
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_22-299_D-22-299
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_22-299_D-22-299
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_22-299_D-22-299
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_22-299_D-22-299
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_22-299_D-22-299
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_22-299_D-22-299
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_22-299_D-22-299
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_22-299_D-22-299
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_22-299_D-22-299
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_22-299_D-22-299
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 551640620	Electronic Service	No	OFF_SL_22-299_D-22-299
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_22-299_D-22-299
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_22-299_D-22-299
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_22-299_D-22-299
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_22-299_D-22-299
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_22-299_D-22-299
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_22-299_D-22-299
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_22-299_D-22-299
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_22-299_D-22-299
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-299_D-22-299
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_22-299_D-22-299
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_22-299_D-22-299
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_22-299_D-22-299
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_22-299_D-22-299
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-299_D-22-299

Document X01-1776-001, Rev. 0

DISMANTLING COST STUDY

for

Allen S. King Unit 1
Angus Anson Units 1-4
Black Dog Units 2, 3, 5 and 6
Blue Lake Units 1-4, 7 and 8
Granite City Units 1-4
Hennepin Island
High Bridge Units 1-3
Inver Hills Units 1- 6
Key City Units 1-4
Maplewood Gas Plant
Minnesota Valley Units 1-3
Red Wing Units 1 & 2
Riverside Units 7, 8, 9 and 10
Sherburne County Units 1-3
Sibley Gas Plant
Wescott Gas Plant
Wilmarth Units 1 & 2
Stations

Blazing Star I Wind Farm
Border Winds Project
Courtenay Wind Farm
Foxtail Wind Farm
Grand Meadow Wind Farm
Lake Benton II Wind Farm
Nobles Wind Farm
Pleasant Valley Wind Farm

prepared for

Xcel Energy

prepared by

TLG Services, Inc.
An Entergy Company
148 New Milford Road East
Bridgewater, CT

April 2020

APPROVALS

Project Engineer	Benjamin J. Stochmal	4/1/20 Date
Project Engineer	Timothy A. Arnold	4/1/2020 Date
Project Manager	Roderick Knight	4/1/2020 Date
Technical Manager	Francis. W. Seymore	4/1/2020 Date

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

SECTION **PAGE**

TABLE OF CONTENTS
(continued)

SECTION **PAGE**

TABLES

TABLE OF CONTENTS
(continued)

SECTION **PAGE**

TABLES
(continued)

FIGURES

APPENDICES

REVISION LOG

Rev. No.	CRA No.	Date	Item Revised	Reason for Revision
0		04/01/2020		Final Issue

ACRONYMS / DEFINITIONS

- AIF Atomic Industrial Forum
- CT Combustion Turbine
- CCGT Combined Cycle Gas Turbine
- DOC Decommissioning Operations Contractor
- DOE Department of Energy
- HRSG Heat Recovery Steam Generator
- LS Lump Sum
- Mtr Motor
- MV Medium Voltage
- Mw Megawatt
- MWe Megawatt (electric) – 2020 Net Max. Capacity (NMC) Rating
- NESP National Environmental Studies Project
- NG Natural Gas
- OSHA Occupational Safety & Health Administration
- PCB Polychlorinated Biphenyl
- RDF Refuse Derived Fuel
- TLG TLG Services, Inc.
- WTG Wind Turbine Generator

EXECUTIVE SUMMARY

This report, prepared by TLG Services, Inc. (TLG), provides estimated costs for the complete dismantling, unless otherwise specified, of the following electric generating stations, wind farms, gas storage and production plants operated by Xcel Energy (Xcel), which either owns or has a share in ownership in each of these facilities:

Generating Stations Located in Minnesota:
- Allen S. King
- Black Dog
- Blue Lake
- Granite City
- Hennepin Island
- High Bridge
- Inver Hills
- Key City
- Minnesota Valley
- Red Wing
- Riverside
- Sherburne County
- Wilmarth

Generating Station Located in South Dakota:
- Angus Anson

Gas production and storage plants (all located in Minnesota):
- Maplewood
- Sibley
- Wescott

Wind Farms Located in Minnesota:
- Blazing Star I Wind Farm
- Grand Meadow Wind Farm
- Lake Benton II Wind Farm
- Nobles Wind Farm
- Pleasant Valley Wind Farm

Wind Farms Located in North Dakota:
- Border Winds Project
- Courtenay Wind Farm
- Foxtail Wind Farm

The dismantling estimate includes the cost of removing the equipment and structures for each of the above-referenced facilities and limited restoration of the sites. The electrical switchyards are assumed to remain in place and are not included in the estimate.

The scope of the dismantling estimate includes the following significant work activities and labor, equipment, material, and waste disposal cost elements:

- Preparation of the units for safe dismantling
- Abatement of asbestos containing materials prior to dismantling (where applicable)
- Removal and disposition of all installed equipment (except where noted)
- Demolition and disposition of subsurface utilities and buildings and foundations (except where noted)
- Removal of below grade foundations (except where noted)
- Coal yard and ash pond remediation (Sherburne County, King, and Minnesota Valley)
- Limited site restoration (grading and seeding for drainage and erosion control)
- Demolition contractor's on-site management, engineering, safety, and administrative staff
- Demolition contractor's expenses, including profit, insurance, permits, and fees
- Xcel's on-site management, oversight, and security staff
- A cost credit associated with the disposition of scrap metals
- Cost contingency

The general approach in assembling the estimate was to develop an inventory of equipment and structures designated to be removed for each facility. This inventory was established using site walk-downs (including discussions with the Operations & Maintenance staff), station-provided equipment databases, and plant drawings. This inventory accounted for similarities between facilities.

The abatement, removal, demolition and restoration activity costs are estimated by applying unit cost factors (developed for each inventory item) against the inventory. Costs for project management, shared equipment and consumables, and similar types of costs are estimated on a period-dependent basis (i.e., the magnitude of the expense depends, in part, on the duration of the project and the types of activities taking place). The potential value of scrap from materials generated in dismantling the plant components and building structural steel is included as a credit in the dismantling cost estimate. Contingency is provided within this estimate to account for unpredictable project events.

OSHA states that demolition involves additional hazards due to unknown factors which make demolition work particularly dangerous. OSHA further states that the hazards of demolition work can be controlled and eliminated with the proper planning, the right personal protective equipment, necessary training, and compliance with OSHA standards. This cost estimate is intended to provide sufficient monies to allow Xcel management to perform the project using these principles and standards.

The dismantling costs, expressed in thousands of 2019 dollars, are provided in the following table.

SUMMARY OF DISMANTLING COSTS
(All costs are in thousands of 2019 dollars)

Station	Unit	MWe rating	Type	Fuel	In Service	Station Cost
Electric Generation Facilities –Fossil and Hydro						
Allen S. King	1	511	Steam	Coal	1968	65,755
Angus Anson	1		Steam	N/A	1966	12,727
	2	109	CT	NG/Oil	1994	
	3	109	CT	NG/Oil	1994	
	4	168	CT	NG/Oil	2005	
Black Dog	2	117	Steam	(note 1)	1952	48,729
(Unit 3 Retired)	3	108	Steam	Coal/NG	1955	
	5	181	CCGT	NG	2002	
	6	228	CT	NG	2018	
Blue Lake	1	50	CT	NG/Oil	1974	16,670
	2	50	CT	NG/Oil	1974	
	3	46	CT	NG/Oil	1974	
	4	48	CT	NG/Oil	1974	
	7	174	CT	NG/Oil	2005	
	8	177	CT	NG/Oil	2005	
Granite City	1	18	CT	NG/Oil	1969	4,885
(All Units Retired)	2	18	CT	NG/Oil	1969	
	3	18	CT	NG/Oil	1969	
	4	18	CT	NG/Oil	1969	
Hennepin Island	1-5	13.9	Hydro	Water	1882	6,352
High Bridge	1	185	CCGT	NG/Oil	2008	16,983
	2	185	CCGT	NG/Oil	2008	
	3	236	Steam	(note 2)	2008	
Inver Hills	1	62	CT	NG/Oil	1972	11,777
	2	62	CT	NG/Oil	1972	
	3	62	CT	NG/Oil	1972	
	4	62	CT	NG/Oil	1972	
	5	61	CT	NG/Oil	1972	
	6	62	CT	NG/Oil	1972	

SUMMARY OF DISMANTLING COSTS
(continued)
(All costs are in thousands of 2019 dollars)

Station	Unit	MWe rating	Type	Fuel	In Service	Station Cost
Electric Generation Facilities -Fossil						
Key City	1	18	CT	NG/Oil	1970	4,530
(All Units Retired)	2	18	CT	NG/Oil	1970	
	3	18	CT	NG/Oil	1970	
	4	18	CT	NG/Oil	1970	
Minnesota Valley	1	10	Steam	Coal	1949	22,508
(All Units Retired)	2	10	Steam	Coal	1949	
	3	44	Steam	Coal	1953	
Red Wing	1	9	Steam	RDF	1949	15,549
	2	9	Steam	RDF	1949	
Riverside	7	160	Steam	(note 3)	1964	40,725
(Unit 8 Retired)	8	231	Steam	Coal	2009	
	9	171	CT	NG/Oil	2009	
	10	171	CT	NG/Oil	2009	
Sherburne County	1	680	Steam	Coal	1976	168,356
	2	682	Steam	Coal	1977	
	3	876	Steam	Coal	1987	
Wilmarth	1	9	Steam	RDF	1948	15,903
	2	9	Steam	RDF	1951	
Gas Production/Storage Facilities						
Maplewood					1957	5,113
Sibley					1953	4,589
Wescott					1972	11,242
Fleet Totals		**6,439**				**$472,396**

NOTES:
1 Unit 2 receives steam from Units 5 HRSG
2 Unit 3 receives steam from Units 1 and 2 HRSGs
3 Unit 7 receives steam from Units 9 and 10 HRSGs

SUMMARY OF DISMANTLING COSTS
Wind Farms (Complete Removal)
(All costs are in thousands of 2019 dollars)

Station	Units	MWe rating	Type	Wind Farm Cost
Electric Generation Facilities -WTG				
Blazing Star I	100	200	Wind Turbine Generator	34,766
Border Winds	75	148	Wind Turbine Generator	30,974
Courtenay	100	190	Wind Turbine Generator	36,313
Foxtail	75	150	Wind Turbine Generator	27,558
Grand Meadow	67	99	Wind Turbine Generator	25,036
Lake Benton II	44	99	Wind Turbine Generator	16,829
Nobles	134	197	Wind Turbine Generator	43,589
Pleasant Valley	100	196	Wind Turbine Generator	38,738
Fleet Totals		**1,279**		**$253,804**

SUMMARY OF DISMANTLING COSTS
Wind Farms (Removal to 48 inches below grade)
(All costs are in thousands of 2019 dollars)

Station	Units	MWe rating	Type	Wind Farm Cost
Electric Generation Facilities -WTG				
Blazing Star I	100	200	Wind Turbine Generator	28,362
Border Winds	75	148	Wind Turbine Generator	25,046
Courtenay	100	190	Wind Turbine Generator	29,087
Foxtail	75	150	Wind Turbine Generator	22,288
Grand Meadow	67	99	Wind Turbine Generator	21,697
Lake Benton II	44	99	Wind Turbine Generator	14,197
Nobles	134	197	Wind Turbine Generator	35,955
Pleasant Valley	100	196	Wind Turbine Generator	31,505
Fleet Totals		**1,279**		**$208,138**

1. INTRODUCTION

1.1 OBJECTIVE OF STUDY

The objective of this dismantling cost study prepared by TLG Services is to present an estimate of the costs to dismantle Xcel Energy's fossil-fueled and wind farm generating electrical generating facilities, plus their gas production and storage facilities, in Minnesota, South Dakota, and North Dakota. This study is not intended to be a dismantling plan for each of the stations, but a cost estimate prepared to support current financial planning for future dismantling.

1.2 FACILITY DESCRIPTIONS

<u>**Electric Generation Facilities**</u>

Allen S. King is a single unit coal fired generating facility with a cyclone-fired boiler. It has a generating capacity of 511 MWe while burning low sulfur Wyoming coal. The plant is located in Oak Park Heights, Minnesota, on the St. Croix River. The unit was installed in 1968. From 2004 to 2007 the unit was completely refurbished as part of an emissions reduction project.

Angus Anson is a three-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. Units 1 and 2 were placed in service in 1994. Unit 3 was placed in service in 2005. The station generating capacity is 386 megawatts. Unit 1, 2, and 3 are rated at 109, 109, and 168 MWe, respectively. The station is located in Sioux Falls, South Dakota adjacent to the decommissioned Pathfinder nuclear facility. The remaining Pathfinder facility features holds the non-nuclear remnants of the test nuclear power plant (minus the reactor) built in 1965.

Black Dog generating station is located on the Minnesota River just south of the Twin Cities. Unit 5, which is a natural gas fired combined cycle combustion gas turbine, replaced the original Unit 1 boiler and steam turbine. The exhaust heat from Unit 5 gas turbine generates steam in the HRSG and powers the original Unit 2 steam turbine that was installed in the 1950's. The Unit 2 boiler has been abandoned in place. The boiler chimney has been removed. Units 3 is abandoned in place and Unit 4 was mostly removed to make room for a new simple cycle combustion gas turbine, Unit 6. The Unit 4 primary precipitator, air heater, forced draft, induced draft and gas recirculation fans, deaerator and storage tank, and one feed-water heater remain in place. The coal yard facilities have been removed as well as the boiler chimneys.

Blue Lake is a six-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity is 545 megawatts. Units 1-4 are rated at 50 MWe, 50 MWe, 46 MWe, 48 MWe, respectively. Units 7 and 8 are rated at 174 MWe and 177 MWe. The station is located in Shakopee, Minnesota along the Minnesota River. Units 1-4 were placed in service in 1974. Units 7 and 8 were placed in service in 2005.

Granite City is a four-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity was 72 megawatts with each of the four units rated at 18 MWe. The station is located in St. Cloud, Minnesota. The units were installed in 1970. The station was retired from service in June 2019.

Hennepin Island is a hydroelectric power plant located on the Mississippi River in Minneapolis, MN, on the west side of Hennepin Island. The station consists of five turbine-generator sets, and has a combined generating capacity is 13.9 Mw. The plant was installed in 1882; it was last refurbished in 2010.

High Bridge is a three-unit facility consisting of two combined cycle combustion gas turbines and one steam turbine. The combustion turbines are each direct coupled to a 185 MWe electric generator. The exhaust gas of each combustion turbine is ducted through its own HRSG. The steam from the HRSG is piped to a 236 MWe steam turbine. The station has a net dependable capacity of 606 MWe. The station was placed in service in 2008. It is located in downtown St. Paul, Minnesota, on the Mississippi River.

Inver Hills is a six-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity is 371 megawatts. Units 1-4 and 6 are rated at 62 MWe each. Unit 5 is rated at 61 MWe. The station is located in Inver Grove Heights, Minnesota. The units were placed in service in 1972.

Key City was a four-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity was 72 megawatts with Units 1-4 at 18 MWe each. The station is located in Mankato, Minnesota. The units were installed in 1970, and retired in March of 2015.

Minnesota Valley is a three-unit facility abandoned in place. The station consists of two 10 MWe and one 44 MWe coal fired units. The station is located in Chippewa County, Granite Falls, Minnesota. The two 10 MWe units were installed in the late 1940's. The third unit was installed in 1953. The station was retired from service in 2013. All coal yard facilities have been removed.

Red Wing is a two-unit generating facility that burns processed municipal solid waste, referred to as refuse-derived fuel (RDF). The station employs a combination duct scrubber with a baghouse to effectively cut emissions from burning RDF. The scrubber treats flue gas with a water spray and dry lime. The baghouse traps particulate by forcing gas streams through large filter bags. The generating capacity of each unit is 9 MWe. The station is located in Red Wing, Minnesota. The units were installed in the early 1950's (coal fired units) and later modified to burn RDF.

Riverside is a three-unit facility consisting of two combined cycle combustion gas turbine generators (Units 9 and 10) and one steam turbine (refurbished Unit 7 steam turbine). The combustion turbines are each direct coupled to a 171 MWe electric generator. The exhaust gas of each combustion turbine is ducted through its own HRSG. The steam from the HRSG is piped to the Unit 7 160 MWe steam turbine. Abandoned in place, and included in this estimate, are the retired Units 6, 7 and 8 boilers, and the Unit 8 steam turbine with all its associated piping and system components. The three operational units went into service in 2009. The station is located northeast of Minneapolis on the Mississippi River.

Sherburne County is a three-unit 2,238 MWe coal-fired facility. The station is located in Becker, Minnesota, 45 miles northwest of the Twin Cities, on the Mississippi River. Units 1, 2 and 3 have a net dependable capacity of 680, 682, and 876 MWe each, respectively. The units were installed in 1976, 1977, and 1987.

Wilmarth is an electric generating facility that burns RDF. The station employs a combination duct scrubber with a baghouse to effectively cut emissions from burning RDF. The scrubber treats flue gas with a water spray and dry lime. The baghouse traps particulate by forcing gas streams through large filter bags. The generating capacity of Unit 1 and 2 is 9 MWe each. The station is located in Mankato, Minnesota. The units were installed in the early 1950's and modified in 1987 to burn RDF.

Gas Production/Storage Facilities

Maplewood is a propane storage facility with an effective propane storage capacity of 1.355 million gallons. The plant, located in Maplewood, Minnesota, was placed in-service in 1957.

Sibley is a propane storage facility used to supplement natural gas supplies during peak demand periods, with an effective propane storage capacity of 1.2

million gallons. The plant, located in Mendota Heights, Minnesota, was placed in service in 1953.

Wescott is a liquefied natural gas peak-shaving plant. The facility collects and stores natural gas for future supply to the local natural gas distribution systems during cold winter periods when regional natural gas supplies may not meet the increased demand. The facility is located in Inver Grove Heights, Minnesota, and was completed in 1972.

Wind Farms

Blazing Star I is a 100-unit wind turbine complex located on privately owned farmland in Lincoln County in southwestern Minnesota. The wind farm is composed of 10, 2.0 MWe V-110 and 90, 2.0 MWe V-120 Vestas wind turbines for a complex total of 200 MWe. The units are expected to be placed into full service in 2020.

Border Winds Project is a 75-unit wind turbine complex located on privately owned farmland in Rolla, North Dakota. The wind farm is composed of 75, 2.0 Mwe (nominal) V-100-2.0 Vestas wind turbines for a complex total of 148 MWe. The units were placed into service in 2015.

Courtenay is a 100-unit wind turbine complex located on privately owned farmland in Jamestown, North Dakota. The wind farm is composed of 100, 2.0 MWe (nominal) V-100-2.0 Vestas wind turbines for a complex total of 190 MWe. The units were placed into service in 2016.

Foxtail is a 75-unit wind turbine complex located on privately owned farmland in Kulm, North Dakota. The wind farm is composed of 7, 2.0 MWe V-110 and 68, 2.0 MWe V-120 Vestas wind turbines for a complex total of 150 MWe. The units were placed into service in 2019.

Grand Meadow is a 67-unit wind turbine complex located in a stretch of farm fields six miles long and four miles wide. The farm is spread out over roughly 10,000 acres southeast of Interstate 90 in Grand Meadow, Clayton, and Dexter Townships in Mower County, Minnesota. Each GE 1.5-77 wind turbine / generator set has a rated capacity of 1.5 Mwe (nominal) for a complex total of 99 MWe. The units were placed in service in 2008.

Lake Benton II is a 44-unit wind turbine complex located on privately owned farmland in Ruthton, Minnesota. The wind farm is composed of 5, 2.1 Mwe (nominal) GE 2.1-116 and 39, 2.3 Mwe (nominal) GE 2.3-116 General Electric wind turbines for a complex total of 99 MWe. The units were placed into service in 2019.

Nobles is a 134-unit wind turbine complex located in the Buffalo Ridge area of Minnesota. The wind farm is spread out over roughly 42 square miles in Nobles County, Minnesota, in Olney, Dewald, Larkin, and Summit Lake townships. Each GE 1.5-77 wind turbine / generator set has a rated capacity of 1.5 Mwe (nominal) for a complex total of 197 MWe. The units were placed in service in 2011.

Pleasant Valley is a 100-unit wind turbine complex located on privately owned farmland in Dexter, Minnesota. The wind farm is composed of 100, 2.0 (nominal) MWe V-100-2.0 Vestas wind turbines for a complex total of 196 MWe. The units were placed into service in 2015.

1.3 SCOPE

The scope of the dismantling estimate includes the following significant cost elements:

- Preparation for safe dismantling;
    - Hazardous materials characterization for such items as ACM (asbestos-containing materials), lead, mercury, PCBs, hydrocarbons in soil, etc.
    - Isolation of the units in preparation for safe dismantling (e.g. ensuring systems are de-energized, fuel and chemical storage tanks are drained and cleaned, etc. (where applicable)
- Abatement of ACM prior to dismantling (where applicable)
- Labor, equipment, and material costs associated with the removal and disposition of all installed equipment
- Labor, equipment, and material costs associated with the demolition and disposition of buildings and foundations
- Demolition contractor's on-site management, engineering, safety, and administrative staff
- Demolition contractor's expenses, including insurance, permits, and fees.
- Xcel's on-site management, oversight, and security staff
- A cost credit associated with the disposition of scrap metals
- Cost contingency

Costs are provided for each generating station or facility, identified by significant cost element. The cost per station includes the costs for dismantling the generating unit and the common station facilities. Costs are provided in 2019 dollars.

1.4 GENERAL APPROACH

The general approach in assembling the estimate was to develop an inventory of equipment and structures designated to be removed for each facility. This inventory was established using site walk-downs (including discussions with the Operations & Maintenance staff), station-provided equipment databases, and plant drawings. This inventory accounted for similarities between facilities.

The abatement, removal, demolition and restoration activity costs are estimated by applying unit cost factors (developed for each inventory item) against the inventory. Costs for project management, shared equipment and consumables, and similar types of costs are estimated on a period-dependent basis (i.e., the magnitude of the expense depends, in part, on the duration of the project and the types of activities taking place). The potential value of scrap from materials generated in dismantling the plant components and building structural steel is included as a credit in the dismantling cost estimate. Contingency is provided within this estimate to account for unpredictable project events.

OSHA states that demolition involves additional hazards due to unknown factors which make demolition work particularly dangerous. OSHA further states that the hazards of demolition work can be controlled and eliminated with the proper planning, the right personal protective equipment, necessary training, and compliance with OSHA standards. The cost estimate is intended to provide sufficient monies to allow Xcel management to perform the project using these principles and standards.

Limited site landscaping is included, which covers grading and seeding for drainage and erosion control.

Section 2 of this report identifies the activities and sequence of activities necessary to dismantle a generating station. Section 3 provides the specific bases for the estimate. Section 4 discusses scrap metal and associated credits to the dismantling costs. Section 5 provides the results. Appendices, noted throughout this report, provide additional information important to understanding this estimate.

2. DISMANTLING OPERATIONS

The estimate for dismantling the stations is based on the complete removal of the units and common station facilities (except where noted). The following sections describe the project organization, basic activities, and special equipment necessary for accomplishing the dismantling project.

The actual dismantling program begins once the station owner has decided to dismantle the site, either immediately following final shutdown, or after a period of storage following final shutdown. The dismantling program has been organized into three distinct periods: Period 1 - Engineering/Planning and Asbestos and Other Hazardous Material Abatement (if necessary); Period 2 - Dismantling Operations; and Period 3 - Site Restoration. This section summarizes the activities performed under each Period of the program.

For the purposes of this estimate it is assumed that once the decision to dismantle has been made and a project start date established, the work in each of these periods will be completed successively (no delay between periods). This report does not attempt to describe all of the activities necessary to dismantle a station, but identifies representative activities appropriate to this type of project.

2.1 PRE-SHUTDOWN ACTIVITIES

The estimates include a planning staff for a year prior to final shutdown to plan for the dismantling program. A staff of seven full-time equivalent personnel is included in this estimate; smaller stations will have a reduced staffing amount.

2.2 POST-SHUTDOWN PLANT STAFF TRANSITION ACTIVITIES

The estimate is based on each station being shut down and placed into a post-shutdown configuration by the plant staff. The length of time that the facility is in this configuration is indeterminate and the costs for maintaining the facility in this configuration is not included within the scope of this dismantling effort. The activities to be completed post-shutdown, but prior to station dismantling, include:

- Removal of consumables and supplies not needed in the post-shutdown configuration
- Removal of residual fuels (including oil/coal)
- Removal of acids and caustics; flushing and cleaning of storage tanks

- Disposition of surplus bulk chemicals and gas storage containers
- Removal of miscellaneous hazardous wastes and combustible materials
- Installation of any appropriate physical barriers (sealing circulating water system) and/or security barriers

The estimate does not account for an extended period of time between final shutdown of the unit(s) and onset of the dismantling program. As such, the plant operations and maintenance staff would be expected to perform the following activities in the interval of time between final plant shutdown, and the onset of the dismantling program.

- If the unit is to be maintained in a condition where lighting, electricity, heating, water, sanitary, and similar services are to remain active, reconfigure these systems to minimize maintenance requirements
- Maintenance of the facility (maintaining roofs and windows, drain systems, and electrical systems to preclude creating hazardous working conditions in the future)

2.3 DISMANTLING ENGINEERING / PLANNING AND ASBESTOS ABATEMENT

When the decision is made to begin physical dismantling of a station, Xcel Energy will begin field dismantling activities, beginning with engineering and planning, and removal of asbestos and other hazardous materials from the station.

2.3.1 Engineering and Planning

A preliminary planning phase of the program begins once it is has been determined that a station will be dismantled and the project has been authorized to proceed. During this phase, the owner assembles its dismantling management organization, makes appropriate decisions regarding the extent of dismantling and the approach to managing the activities, and accomplishes those site preparation activities necessary to transition from a plant shutdown configuration to site dismantling. For purposes of this estimate it is assumed that the intent is to dismantle the entire station as a single project. Costs incurred during this preliminary phase of the program are included in the dismantling costs presented in this study.

Xcel Energy prepares the stations for dismantling by performing the following activities:

- Prepare specifications that identify and describe the objectives and major work activities to be accomplished (establishing the final site configuration)
- Assemble plant documentation that may be relevant to dismantling (drawings, hazardous material reports, environmental studies, etc.)
- Select an asbestos abatement contractor (if required) and Dismantling Contractor
- Assemble and mobilize the management and oversight team responsible for the project
- Documenting hazardous materials location and inventory

2.3.2 Asbestos / Hazardous Material Abatement (as applicable)

The asbestos abatement contractor prepares for this work by thoroughly understanding the scope of the asbestos remediation work and obtaining the permits necessary to initiate the work. Abatement of asbestos is considered an important prerequisite to dismantling the station's systems and structures. The method by which asbestos is abated is strictly controlled by federal and/or state regulations and includes the following requirements:

- Work will be done inside enclosures designed to capture any asbestos-containing particles. With the exception of removal of small quantities of asbestos in local areas, it would be expected that most work will be done in large enclosures (containment tents). The enclosures will have a filtered exhaust and be maintained under negative air pressure (air will leak into the enclosure rather than leak out).
- The air outside of the enclosures will be monitored to ensure barriers are effective.
- Workers, while working inside enclosures, will wear respiratory protective equipment as well as protective clothing.
- All materials removed from the enclosure will be packaged in accordance with regulations (minimum double-bag), and will be removed via a materials handling access area.
- Workers will enter and exit the enclosures through a personnel decontamination chamber in a controlled manner (ensuring asbestos contamination does not spread beyond the containment).

- After the asbestos abatement is complete, the effectiveness of the process will be established via regulatory-specified processes (generally verifying that there is no asbestos containing material capable of becoming airborne).
- Asbestos containing materials will be disposed of at a properly licensed disposal facility.
- After ensuring that all asbestos has been removed, the enclosures will be taken down in accordance with regulatory requirements and disposed of at a licensed facility.
- Clean coal-fired boilers by washing down all surfaces interior to the boilers.
- Clean fly-ash handling equipment, e.g., filters and holding tanks.
- De-water ash settling ponds and/or basins.

2.3.3 Dismantling Preparations

The dismantling contractor prepares the station for dismantling by performing the following activities:

- Installing environmental barriers and monitoring equipment
- Reviewing plant drawings and specifications that may be useful for the dismantling project
- Identifying the processes to achieve the final desired station configuration
- Identifying the major work sequence
- Preparing dismantling activity specifications and work orders/forms
- Preparing detailed dismantling procedures
- Preparing a dismantling plan
- Preparing permit application(s) for plant demolition
- Mobilizing site staff
- Configuring temporary services/facilities to support dismantling operations
- Arranging for heavy lift and dismantling equipment, rigging, and tooling
- Hiring and training the labor force

2.4 DISMANTLING OPERATIONS

Dismantling activities are initiated after completing the engineering and planning process, and after asbestos abatement and removal of hazardous materials is complete. The sequence of activities will be determined at the time of dismantling, but typically a sequence would include the following items. Dismantling sequences are presented for each of the Xcel Energy facility types. In all types the station is electrically disconnected from all power sources; the Dismantling Contractor will provide temporary power as needed to support the removal activities.

2.4.1 Steam Plants

- Removing coal yard equipment (if required), including unloading structures, conveyors, transfer towers, and reclaim systems
- Removing above-ground storage tanks
- Removing large equipment from rooftops or at higher elevations
- Removing equipment that must be removed prior to start of boiler structure removal, including fly-ash handling, coal handling, burner fuel supply, scrubbers, air and flue gas ducts, etc.
- Removing electrostatic precipitator and bag houses by cutting casings and connecting gas ducts
- Removing the top of the boiler enclosure to allow access to the platens
- Removing the boiler waterwalls
- Removing steam drum and deaerator by severing all connections and lowering to grade
- Removing boiler structural steel
- Disassembling the turbine/generator and condenser
- Removing all other equipment and components required prior to structures demolition
- Removing the turbine building superstructure and interior floors
- Blasting/dismantling the concrete turbine-generator pedestal(s)
- Removing siding from buildings
- Dismantling steel framing
- Demolishing structural concrete

- Removing the stack(s)
- Removing cooling tower(s) and / or cooling water intake and discharge structures
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to remove reinforcing steel
- Removing any temporary services used to support the dismantling effort (lighting / ventilation / electrical / groundwater management)

2.4.2 Combustion Turbines

- Removing above-ground storage tanks
- Removing large equipment from rooftops or at higher elevations
- Disassembling the turbine and generator
- Removing all other equipment and components required prior to building demolition
- Blasting/dismantling the concrete turbine-generator foundation(s)
- Demolishing remaining concrete
- Removing cooling tower(s) and / or cooling water intake and discharge structures (High Bridge only)
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to remove reinforcing steel

2.4.3 Hydroelectric Plants

- Installing cofferdams at inlet to power channel and discharge channel
- Removing large equipment from rooftops or at higher elevations
- Disassembling and removing the generators
- Disassembling and removing the water turbines
- Removing all other equipment and components required prior to structures demolition

- Removing the powerhouse structure and interior floors
- Blasting/dismantling the concrete turbine-generator foundations
- Dismantling steel framing
- Demolishing brick walls and structural concrete
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to remove reinforcing steel

2.4.4 Wind Turbines (complete removal)

- Removing turbine blades from turbine shaft
- Removing turbine-generator housings from towers
- Removing towers from foundations
- Removing all other equipment and components required prior to structures demolition
- Blasting/dismantling the concrete tower foundations
- Excavating and removing all buried electrical cables
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to enhance its suitability for backfill

2.4.5 Wind Turbines (removal to 48" below grade)

- Removing turbine blades from turbine shaft
- Removing turbine-generator housings from towers
- Removing towers from foundations
- Removing all other equipment and components required prior to structures demolition
- Removing the concrete tower foundation pedestal to 48" below grade
- Buried electrical cables below 48" left in place
- Removing all other site structures within the scope of the dismantling program

- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to enhance its suitability for backfill

2.5 SITE RESTORATION

Site restoration activities are initiated following completion of the dismantling operations. The objective of site restoration in this estimate is to restore the station grounds to a configuration that does not pose a safety hazard; and plant vegetation for erosion control. As such, landscaping will be limited to grading, placement of top soil, and seeding. Site restoration as used in this estimate is not intended to re-configure the station for redevelopment, e.g. use as a recreational or industrial facility.

A typical site restoration sequence would be:

- Crush all concrete rubble and remove reinforcing steel. Concrete debris will be shipped off site for disposal as construction debris. Reinforcing steel will be recycled
- Backfill below grade voids with clean compactible fill as necessary.
- General grading of the station
- Placement of top soil or other suitable surface material necessary to maintain erosion control
- Landscaping to the extent necessary to re-vegetate the station (grass or similar plant materials), and
- Demobilizing personnel and equipment

3. COST ESTIMATE

The basis, methodology, and assumptions for the site-specific cost estimate are described in the following paragraphs.

3.1 BASIS OF ESTIMATE

Inventory of Materials to be Removed

The inventory is an essential element of the estimate, since dismantling costs are determined by applying unit cost factors against the corresponding inventory quantities. For each of these estimates a site-specific inventory of materials to be removed was developed using a combination of methods. The inventory used in developing the estimate for each station is provided in Appendix A.

Comparable Boiler / Turbine Unit Information Available to TLG Where TLG had previously developed inventory information for a boiler and turbine of similar size, fuel type and vintage, referred to as "reference unit", this information was used to represent the boiler / turbine systems inventory for the comparable Xcel Energy unit. In the same manner, non-steam power facilities were also used as reference units for other, similar Xcel Energy facilities. The inventory was adjusted to reflect the difference between the rating of the Xcel Energy reference unit and the rating of the comparable unit.

There are expected differences in other facilities, even if the power generating equipment are similar between comparable units. These include systems and structures associated with cooling water intake and discharge, fuel handling, exhaust gas, maintenance buildings and shops, pollution-control, and the quantity and extent of asbestos containing material (if applicable). For these systems and structures TLG developed the inventory by conducting a walk-down of the station, and extracting information from station-specific drawings and photos.

Comparable Plant Information Not Available to TLG Where the Xcel Energy unit(s) had no comparable match in the TLG database, the site specific inventory was developed "from scratch", by completing a physical walk-down of each such unit, discussions with the stations' Operations & Maintenance staff, and extracting data from station-specific maintenance databases (lists of equipment), drawings, and photos.

Economic Cost Drivers (Reference in Section 6)

In developing an estimate, the cost of labor, equipment and material, credit for scrap, and similar costs will influence the results of the estimate. The basis for the significant cost drivers are:

1. Craft labor rates are based on existing contracts with craft labor contractors. These rates were provided by Xcel Energy (Ref. 1).
2. Utility labor rates are based on labor costs for positions likely to be employed during the dismantling project. The 2014 rates were escalated to 2019 values, per Xcel Energy approval, using U.S. Department of Labor's Bureau of Labor Statistics, Consumer Price Index Series ID:CUUR0000SAS (Ref. 2).
3. Material and equipment costs for conventional demolition and/or construction activities, Contractors Insurance, Small Tools Allowance, Permit / Fees, and Contractor's Fee are based on R.S. Means Construction Cost Data (Ref. 3).
4. Scrap metal prices are based on a five-year average of published indices (Ref. 4).
5. Contingency, contractor fee, contractor insurance, environmental sampling, and permits & fees are based upon R.S. Means Construction Cost Data.
6. Costs in this estimate are in 2019 dollars.
7. Property taxes (or payments in lieu of taxes) are not included within the estimate.
8. The estimate to dismantle the stations does not address credit associated with the residual value of the land.

Project Organization

For the purposes of this study, the dismantling project for each station is assumed to be managed by Xcel Energy's Project Director, who would have the primary responsibility for dismantling the station. A Dismantling Contractor, experienced in dismantling similar facilities, would be hired as the prime contractor for the removal of plant components and site facilities. The Dismantling Contractor's Project Manager would report to the Project Director. The Dismantling Contractor would manage and supervise the dismantling activities of the station and be responsible for completing the work in an expeditious and safe manner. Contractor personnel would manage and direct the labor force in accordance with approved procedures and in accordance with a health and safety program. The Xcel staff would maintain and/or provide the engineering, safety, and environmental compliance oversight, and the security services necessary to support dismantling operations. Figures 3.1 and 3.2 identify typical organizations for the plant/utility staff and the associated contractor personnel during the dismantling phase of the project. The smaller facilities included within this estimate would have a commensurately smaller project organization e.g. Angus Anson, Blue Lake, and Grand Meadow.

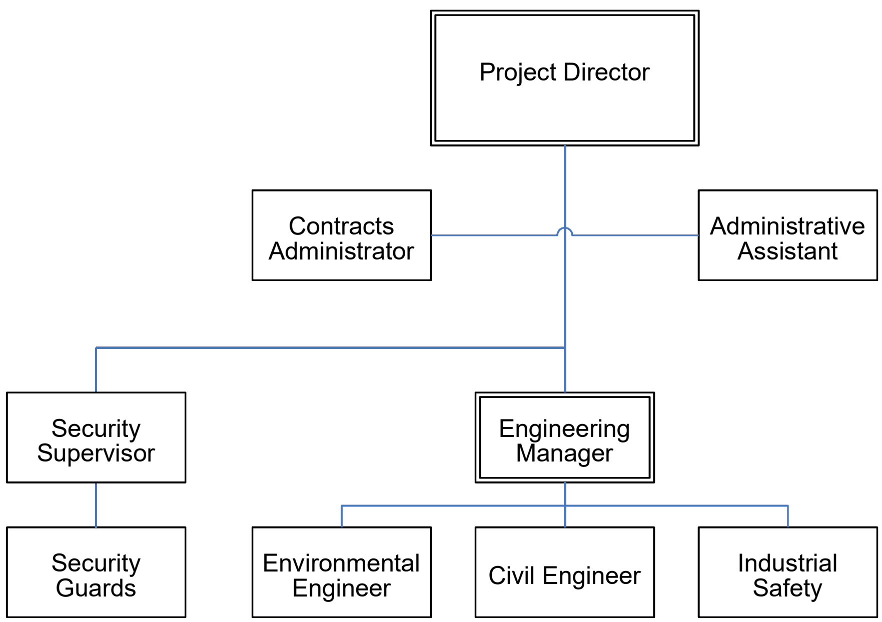
3.2 METHODOLOGY

The methodology used to develop the cost estimate follows the basic approach presented in the AIF/NESP-036, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (Ref. 5) and the US DOE "Decommissioning Handbook" (Ref. 6). These publications utilize a unit cost factor method for estimating decommissioning activity costs to simplify the estimating calculations. Unit cost factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/in) are developed from the labor cost information from R. S. Means. The activity-dependent costs are estimated using item quantities (cubic yards, tons, inches, etc.) developed from plant drawings and inventory documents. The unit factors used in this study reflect the latest available information on worker productivity in plant dismantling. A sample unit cost factor is provided in Appendix B. A list of unit cost factors is provided in Appendix C.

An activity duration critical path is developed to determine the total dismantling program schedule. This program schedule is then used to determine the period-dependent costs for program management, administration, field engineering, equipment rental, quality assurance, and security. TLG escalated 2014 Xcel Energy salary and hourly rates for personnel associated with period-dependent costs. The costs for conventional demolition of structures, materials, backfill, landscaping, and equipment rental are obtained from R.S. Means. Examples of such unit cost factor development are presented in AIF/NESP-036.

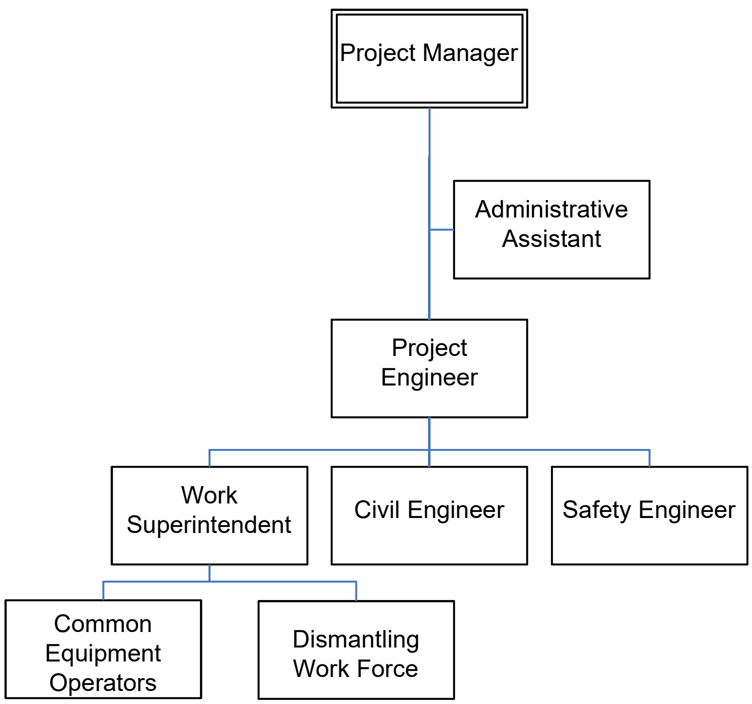
The unit cost factor method provides a demonstrable basis for establishing reliable cost estimates. The detail of activities for labor costs, equipment and consumables costs provide assurance that cost elements have not been omitted. Detailed unit cost factors, coupled with the site-specific inventory of piping, components and structures provide confidence in the cost estimates.

FIGURE 3.1
DISMANTLING PROJECT ORGANIZATION
UTILITY STAFF



For a large station such as Sherburne County, this represents a full-time equivalent staffing level of six personnel. This value is reduced for smaller stations.

FIGURE 3.2
DISMANTLING PROJECT ORGANIZATION
DECOMMISSIONING CONTRACTOR STAFF



For a large station such as Sherburne County, this represents a full-time equivalent staffing level of 11.5 personnel. This value is reduced for smaller stations.

The activity-dependent and period-dependent costs are combined with applicable collateral costs to yield the direct decommissioning cost. A contingency is then applied. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook" (Ref. 7) as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this estimate are based on ideal conditions; therefore, a contingency factor has been applied.

Examples of items that could occur but have not otherwise been accounted for in this estimate include: labor work stoppages, bad weather delays, equipment/tool breakage, changes in the anticipated plant shutdown conditions, etc. These types of unforeseeable events are discussed in the AIF/NESP-036 study. Guidelines are also provided for applying contingency.

3.3 ASSUMPTIONS

The following assumptions were used in developing the dismantling estimate.

<u>Pre-requisite Activities</u>

1. Dismantling of the station will not commence until all units are retired (cost estimate is not based on independent dismantling of units while adjacent units are operating).
2. The arrangements of the unit facilities as they exist in 2019 based upon walk-downs conducted by TLG, and databases and drawings provided by owner.
3. The dismantling process will be an engineered process with substantial consideration for occupational (worker) safety.
4. The demolition will be performed by a Dismantling Contractor who is responsible to provide adequate staff and equipment to complete the dismantling in a safe manner.
5. Site security costs to restrict access to the demolition project by unauthorized personnel are included.
6. The estimates are based on industrial safety and environmental regulations effective in 2019.
7. All power to the structures will be disconnected prior to beginning removal activities ("Cold and Dark"). The Decommissioning Contractor will provide for temporary power as needed to support dismantling activities.

8. End of life water inventory management in regulated ponds will be addressed in accordance with federal and state rules and closed in place after shutdown.
9. On-site fuel inventories will be used and/or removed prior to start of dismantling.
10. Silos, precipitators, hoppers, tanks, etc., will be emptied by operations and maintenance staff after shutdown.
11. Acids, caustics, and similar hazardous materials will be removed by operations and maintenance staff after shutdown.
12. Consumables, such as ion exchange materials and filters, will also be removed by operations and maintenance staff after shutdown.
13. Stores, spare parts, gas storage containers, laboratory equipment, office furniture, etc., will be removed by the owner after shutdown.
14. Oils used in station transformers may contain PCBs. Lubricating and transformer oils are drained and removed by operations and maintenance staff after shutdown. If any PCB contaminated oil is encountered, it will be removed and disposed of properly.
15. Asbestos (if present) will be removed prior to the start of dismantling. Asbestos insulation and PACM (presumed asbestos containing materials) will be disposed of at licensed facilities. Quantities of asbestos are based on owner-provided information where available. Where such information was not available, the quantities of asbestos were estimated.
16. Prior to initiating dismantling, essentially all live circuits will have been de-energized (to preclude creating an industrial hazard). If required, temporary services systems (air, water, electrical, fire water, etc.) will be used to support dismantling operations and will remain in service throughout the project until no longer required.

<u>Economic Assumptions</u>

17. Post-shutdown "dormancy" costs (i.e., security and maintenance on any of the units retired prematurely) are not included in the study.
18. Escalation/inflation of the costs over the remaining operating life is not included.
19. An allowance of 2% of craft labor costs is used for small tools.
20. A 12.5% fee is added to the Demolition Contractor's cost to account for its overhead and profit.
21. A 25% contingency is applied to asbestos remediation activities.

22. A 15% contingency is applied to all remaining dismantling-related costs.
23. A credit for scrap metal cost recovery is included in the estimates. Retired plant equipment is assumed to have no value as salvage (sold for re-use).

Physical Work Assumptions

24. The costs for disposition (if required) of contaminated soil (e.g., PCBs, hydrocarbons, lead, asbestos, mercury, acids or caustics) are outside the scope of this estimate.
25. Large equipment and components will be removed prior to structures demolition.
26. An environmental hazards crew will be maintained throughout the demolition period to address such items as lead paint and asbestos that was inaccessible during the asbestos remediation period (where applicable).
27. Turbine pedestals and powerhouse building foundations will be removed by demolition equipment and back-filled to grade.
28. Structures and foundations will be removed with any resulting voids back-filled to grade level. An additional scenario is provided for the wind farms where the equipment and structures are removed only to a depth of 48 inches.
29. Chimney stacks will be blasted to the ground and broken into rubble, the steel liners cut and removed, and the foundations removed.
30. The dismantling of the electrical equipment terminates at the switch yard boundary. The switch yard is left intact.
31. Concrete rubble generated during dismantling will be crushed, reinforcing steel removed, and the concrete disposed of offsite as construction debris.
32. The site will be graded; however, no effort was included in this estimate to restore the original contour of the land. Ground cover will be established for erosion control.
33. Roads, parking lots, etc., are removed after the facility is dismantled (with the exception of the immediate area around the switchyard).

Scheduling Assumptions

34. All work is performed during an eight-hour workday, five days per week, with no overtime.
35. Multiple crews work parallel activities to the maximum extent possible, consistent with efficiency (adequate access for cutting, removal, and

laydown space) and with industrial safety appropriate for demolition of heavy components and structures.

36. Scheduling was calculated without constraints on availability of labor, equipment, or materials.

3.4 STATION-SPECIFIC NOTES

3.4.1 Allen S. King

- All currently operational coal handling equipment and the abandoned-in-place coal barge unloader facility with the twenty-two dolphin-type barge piers are included in the estimate.
- A cofferdam will be installed to allow removal of the condenser cooling water discharge structure and the discharge structure from the cooling tower.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- The soil beneath the area of the coal pile will be removed to a depth of five feet; the soil will be disposed of offsite as solid waste.
- The ash pond will be backfilled with clean fill prior to placement of the closure cap.

3.4.2 Angus Anson

- The Pathfinder Unit 1 building has been included in this estimate.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Concrete will only be removed to three feet below grade.
- Two large oil storage tanks are included in the estimate. One tank is currently in service. The other tank has been cleaned and remains on stand-by.

3.4.3 Black Dog

- The abandoned-in-place Unit 2 boiler is included in the estimate.
- All chimneys from the coal burning operation have been removed.
- All operational coal handling equipment external to the building e.g. conveyors, rail car unloader, transfer towers, stacker conveyor etc. have been removed. Coal conveyors inside the plant have been abandoned in place but not yet removed.
- A cofferdam will be installed to remove the intake condenser cooling water structure.

3.4.4 Blue Lake

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Two large oil storage tanks are included in the estimate. One tank is currently in service. The other tank has been cleaned and remains on stand-by.

3.4.5 Granite City

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Two large oil storage tanks are included in the estimate. The tanks have been cleaned.

3.4.6 Hennepin Island

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- The estimate does not include dam or earthworks removal, or ongoing maintenance.
- Inlet channel to turbines will be backfilled.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.

3.4.7 High Bridge

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

- A cofferdam will be installed to remove the river intake and discharge structure.

3.4.8 Inver Hills

- Gas supply lines will be cut and capped at the source.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.9 Key City

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Two large oil storage tanks are included in the estimate. The tanks have been cleaned.

3.4.10 Maplewood Gas Plant

- Facility includes multiple liquefied natural gas storage tanks.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.11 Minnesota Valley

- All three of the abandoned in-place units are included in the estimate.
- The asbestos quantities were calculated considering Unit 3 to be all asbestos and Units 1 and 2 to only have small amounts on the partially dismantled boilers.
- A cofferdam will be installed to remove the river intake and discharge structure.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- All coal yard facilities have been removed and the ash ponds have been closed.

3.4.12 Red Wing

- The RDF unloading facility and the conveyor transport system are included in the estimate.
- A cofferdam will be installed to remove the cooling water intake and discharge structure.
- The barge unloading facility in not included in the estimate.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- The ash landfills will be closed in place by capping with a synthetic liner, placing cover over the cap, and seeding.

3.4.13 Riverside

- Included in this estimate are the following abandoned-in-place facilities and equipment:
    - Unit 6, 7 and 8 building structure
    - Unit 6 and 7 boilers
    - Unit 8 boiler, turbine and associated equipment
- Cofferdams will be installed to remove the four cooling water intake and discharge structures.
- Includes barge unloading dock and concrete piles.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).

3.4.14 Sherburne County

- All coal handling facilities e.g. coal barn, rail car dumper building, coal yard control and maintenance facility, earthen storage berms, conveyor systems, transfer towers etc. are included in this estimate.
- All warehouse/storage type buildings on the site are included in the estimate.
- A cofferdam will be installed to remove the cooling water intake and discharge structure.

- The boiler and precipitator/baghouse will be cleaned prior to dismantling.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM) – Units 1 and 2 only.
- The soil beneath the area of the coal pile will be removed to a depth of five feet; the soil will be disposed of on site in the ash pond.
- The ash pond will be backfilled with coal yard soil prior to placement of the closure cap.
- The Unit 3 dry ash landfill will be closed and capped in accordance with Minnesota's solid waste permit requirements and applicable federal coal combustion residual rules.
- Some of the planning for Sherburne County includes a unit shutdown with the other units remaining in operation for a number of years. In this event, the costs in Table 5.1n, for the shutdown unit only, should be increased by some fraction to allow for constraints on demolition activities on the shutdown with the other units operational. Based upon discussions with Xcel Energy personnel, an increase of 20% can be used for planning purposes.
- The ash landfills will be closed in place by capping with a synthetic liner, placing cover over the cap, and seeding.
- Two large settling tanks are included in the estimate.

3.4.15 Sibley Gas Plant

- Facility includes multiple liquefied natural gas storage tanks.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.16 Wescott Gas Plant

- Facility includes two large insulated liquefied natural gas storage tanks.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.17 Wilmarth

- The RDF bulk storage facility is not included in the estimate. Only the transport section of the facility with conveyor systems and transfer towers is included.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- The ash landfills will be closed in place by capping with a synthetic liner, placing cover over the cap, and seeding.

3.4.18 Wind Farms – Blazing Star I, Border Winds, Courtenay, Foxtail, Grand Meadow, Lake Benton II, Nobles, Pleasant Valley

- All underground power and control cables will be excavated and removed.
- Tower foundations are completely removed.
- All access roads surfaces will be excavated and removed. The excavated areas will be back-filled with soil.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.19 Wind Farms (Removal to 48-inch depth) – Blazing Star I, Border Winds, Courtenay, Foxtail, Grand Meadow, Lake Benton II, Nobles, Pleasant Valley

- All underground power and control cables will be excavated and removed to a depth of 48 inches below grade.
- Tower foundations pedestals will be removed to 48 inches below grade.
- All access roads surfaces will be excavated and removed. The excavated areas will be back-filled with soil.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

4. SCRAP METAL CREDITS

The dismantling of a typical fossil plant occurs after a lengthy plant operating life. The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. Xcel Energy will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that buyers prefer equipment stripped down to very specific requirements before they would consider purchase. This can require expensive work to remove the equipment from its installed location, which is inconsistent with the rapid dismantling approach assumed in this estimate. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall cost of dismantling, this analysis does not attempt to quantify the value that an owner may realize based upon those efforts.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property is removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts are made available for alternative use.

The materials used in the equipment and buildings are suitable for recycle as scrap metals. As such, an estimated value of the scrap metal credit has been developed and applied to each station's cost estimate. The value of scrap was estimated using a five-year average of market values extracted from published sources and applying this value to the estimated quantities of materials generated from the dismantling project. There were four basic types of metals used in the scrap estimates; carbon steel (the most common material used at the station), copper, stainless steel (high alloy steel) and aluminum. The scrap credit, in addition to considering the quantity and types of materials, also considered the cost of handling and transporting these materials to a major scrap processing location in the Twin Cities area where scrap is used or sold. The value of the scrap is reduced by the transportation costs.

The basis for scrap metal value is summarized in Table 4.1. A summary of the basis for the scrap credit is provided in Tables 4.2 which details the scrap quantities by material type from each unit, and Table 4.3 lists the dollar value of these quantities.

TABLE 4.1a
BASIS FOR SCRAP METAL VALUE
(2019 dollars)

Fossil Stations

Type of Material	Scrap Category [1]	Market Value [2]	Units	Transport Cost [3]	Scrap Metal Credit [4] (per ton)
Carbon Steel	Cast Iron	202.40	Per Ton	46.85	155.56
	No. 1	253.01	Per Ton	46.85	206.16
	Mixed Scrap	202.40	Per Ton	46.85	155.56
	Galvanized	55.66	Per Ton	46.85	8.81
Stainless Steel	SS-1	0.77	Per Pound	0.02	1,490.20
Copper	Insulated Cable	1.32	Per Pound	0.02	2,586.11
	No. 2 Copper	2.11	Per Pound	0.02	4,168.50
	Copper-Nickel	3.20	Per Pound	0.02	6,355.94
	Large Motor	0.32	Per Pound	0.02	585.41
Non-Ferrous	Aluminum	0.29	Per Pound	0.02	532.27

Note 1: Scrap categories are consistent with information provided in Recycler's World.

Note 2: The market value for scrap metal used in this estimate is based on Recycler's World U.S. Scrap Metal Index Spot Market Prices. Values shown represent the average over a 5-year period from January 1, 2015 to December 31, 2019 (See Section 6, reference 4).

Note 3: The estimated cost for handling and transporting the materials to a major scrap processing center in the Twin Cities area is $46.85 / ton or $0.023 / pound.

Note 4: The scrap metal credit reflects the market value of scrap adjusted for handling and transport cost to local scrap metal recycler.

TABLE 4.1b
BASIS FOR SCRAP METAL VALUE
(2019 dollars)

Wind Farms

Type of Material	Scrap Category [1]	Market Value [2]	Units	Scrap Metal Credit [3] (per ton)
Carbon Steel	Cast Iron	202.40	Per Ton	202.40
	No. 1	253.01	Per Ton	253.01
	Mixed Scrap	202.40	Per Ton	202.40
	Galvanized	55.66	Per Ton	55.66
Stainless Steel	SS-1	0.77	Per Pound	1,537.05
Copper	Insulated Cable	1.32	Per Pound	2,632.95
	No. 2 Copper	2.11	Per Pound	4,215.35
	Copper-Nickel	3.20	Per Pound	6,402.79
	Large Motor	0.32	Per Pound	632.26
Non-Ferrous	Aluminum	0.29	Per Pound	579.12

Note 1: Scrap categories are consistent with information provided in Recycler's World.

Note 2: The market value for scrap metal used in this estimate is based on Recycler's World U.S. Scrap Metal Index Spot Market Prices. Values shown represent the average over a 5-year period from January 1, 2015 to December 31, 2019 (See Section 6, Reference 4).

Note 3: The scrap metal credit reflects the market value of scrap cost to local scrap metal recycler. Scrap from the wind farms does not include transportation costs; the transport of the scrap from wind farms is separately accounted for in the cost tables *within "Item 1b. Haul Off of Materials (Trucking / Rail).".*

TABLE 4.2a
QUANTITY OF SCRAP METALS BY STATION
(pounds)

Fossil Stations

	Carbon Steel			Stainless Steel	Galvanized	Copper			Copper		
Station Name	**Cast Iron**	**No. 1**	**Mixed Scrap**	**SS-1**	**Steel**	**Insul Cbl**	**No. 2 Cu**	**Large Mtr**	**Nickel**	**Aluminum**	**Total**
Allen S . King	2,976,846	41,253,822	53,751,220	231,075	1,010,675	157,197	590,394	1,816,821	515,763	-	102,303,814
Angus Anson	944,532	7,869,287	10,367,485	366,129	262,382	62,845	555,614	235,889	90,000	-	20,754,163
Black Dog	1,643,294	27,421,437	35,094,140	770,520	691,748	203,840	500,072	1,777,520	221,615	-	68,324,186
Blue Lake	562,895	7,151,454	16,794,779	471,749	151,311	66,137	534,704	167,052	-	-	25,900,081
Granite City	415,622	1,347,785	3,827,752	14,999	123,454	19,672	117,956	37,557	-	-	5,904,796
Hennepin Island	-	696,327	1,821,010	1,204	32,320	17,700	44,413	-	-	-	2,612,973
High Bridge	844,602	11,853,600	18,671,353	312,326	572,357	113,539	661,690	1,016,734	-	-	34,046,202
Inver Hills	203,824	4,050,420	12,115,948	911,580	66,005	-	537,241	6,408	-	-	17,891,426
Key City	415,622	1,000,333	3,795,209	14,999	123,454	19,672	107,108	37,557	-	-	5,513,953
Maplewood	55,689	2,277,558	514,983	109,319	31,504	6,904	16,564	374	-	-	3,012,895
Minnesota Valley	638,559	12,944,074	20,225,105	554,769	397,131	68,843	241,236	1,395,489	294,202	-	36,759,408
Red Wing	269,371	5,792,041	7,537,990	459,747	242,290	29,016	21,797	235,896	34,301	-	14,622,450
Riverside	717,166	26,334,947	48,412,618	275,384	437,669	61,010	596,359	1,432,370	-	-	78,267,523
Sherburne County	4,008,245	133,744,558	185,765,812	2,132,542	3,718,089	836,673	893,799	5,411,303	-	103	336,511,124
Sibley	53,710	1,828,422	373,174	103,107	43,503	6,703	13,829	7,250	-	-	2,429,699
Wescott	47,236	7,963,162	1,606,330	189,165	68,387	33,887	16,236	2,591	-	1,398,204	11,325,198
Wilmarth	303,646	5,170,263	7,265,649	153,131	168,520	29,016	21,797	235,896	80,000	-	13,427,919
Total	**14,100,859**	**298,699,489**	**427,940,558**	**7,071,745**	**8,140,800**	**1,732,655**	**5,470,810**	**13,816,706**	**1,235,881**	**1,398,307**	**779,607,809**

TABLE 4.2b
QUANTITY OF SCRAP METALS BY STATION
(pounds)

Wind Farms (Complete Removal)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I	5,913,057	43,858,999	534,453	6,015,842	2,085,396	58,407,747
Border Winds Project	4,404,257	23,658,643	400,839	3,819,509	1,564,047	33,847,295
Courtenay	5,906,025	35,509,601	534,453	5,092,678	2,085,396	49,128,153
Foxtail	5,655,813	32,880,310	400,839	4,514,897	1,564,047	45,015,907
Grand Meadow	3,862,624	33,764,540	358,083	5,302,782	1,397,215	44,685,245
Lake Benton II	3,244,453	22,905,242	261,714	3,326,828	1,026,369	30,764,606
Nobles	10,771,870	51,911,086	716,166	10,639,600	2,794,431	76,833,154
Pleasant Valley	6,238,545	37,955,390	534,453	5,092,678	2,085,396	51,906,462
Total (Complete Removal)	**45,996,644**	**282,443,812**	**3,741,000**	**43,804,815**	**14,602,298**	**390,588,569**

TABLE 4.2c
QUANTITY OF SCRAP METALS BY STATION
(pounds)

Wind Farms (Down to 48 inches below grade)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I (48 in.)	669,104	43,858,999	11,641	6,015,842	-	50,555,586
Border Winds Project (48 in.)	485,434	23,658,643	8,731	3,819,509	-	27,972,316
Courtenay (48 in.)	662,072	35,509,601	11,641	5,092,678	-	41,275,992
Foxtail (48 in.)	610,801	32,880,310	8,731	4,514,897	-	38,014,739
Grand Meadow (48 in.)	561,512	33,764,540	7,799	5,302,782	-	39,636,634
Lake Benton II (48 in.)	385,519	22,905,242	5,122	3,326,828	-	26,622,712
Nobles (48 in.)	1,306,946	51,911,086	15,599	10,639,600	-	63,873,231
Pleasant Valley (48 in.)	658,709	37,955,390	11,641	5,092,678	-	43,718,418
Total (Down 48 inch Removal)	**5,340,099**	**282,443,812**	**80,903**	**43,804,815**	**-**	**331,669,629**

TABLE 4.3a
SCRAP METAL CREDITS BY STATION
(thousands of 2019 dollars)

Fossil Stations

	Carbon Steel			Stainless Steel	Galvanized	Copper			Copper		
Station Name	**Cast Iron**	**No. 1**	**Mixed Scrap**	**SS-1**	**Steel**	**Insul Cbl**	**No. 2 Cu**	**Large Mtr**	**Nickel**	**Aluminum**	**Total**
Allen S . King	$ 232	$ 4,252	$ 4,181	$ 172	$ 4	$ 203	$ 1,231	$ 532	$ 1,639	$ -	$ 12,446
Angus Anson	$ 73	$ 811	$ 806	$ 273	$ 1	$ 81	$ 1,158	$ 69	$ 286	$ -	$ 3,559
Black Dog	$ 128	$ 2,827	$ 2,730	$ 574	$ 3	$ 264	$ 1,042	$ 520	$ 704	$ -	$ 8,792
Blue Lake	$ 44	$ 737	$ 1,306	$ 352	$ 1	$ 86	$ 1,114	$ 49	$ -	$ -	$ 3,688
Granite City	$ 32	$ 139	$ 298	$ 11	$ 1	$ 25	$ 246	$ 11	$ -	$ -	$ 763
Hennepin Island	$ -	$ 72	$ 142	$ 1	$ 0	$ 23	$ 93	$ -	$ -	$ -	$ 330
High Bridge	$ 66	$ 1,222	$ 1,452	$ 233	$ 3	$ 147	$ 1,379	$ 298	$ -	$ -	$ 4,799
Inver Hills	$ 16	$ 418	$ 942	$ 679	$ 0	$ -	$ 1,120	$ 2	$ -	$ -	$ 3,177
Key City	$ 32	$ 103	$ 295	$ 11	$ 1	$ 25	$ 223	$ 11	$ -	$ -	$ 702
Maplewood	$ 4	$ 235	$ 40	$ 81	$ 0	$ 9	$ 35	$ 0	$ -	$ -	$ 404
Minnesota Valley	$ 50	$ 1,334	$ 1,573	$ 413	$ 2	$ 89	$ 503	$ 408	$ 935	$ -	$ 5,307
Red Wing	$ 21	$ 597	$ 586	$ 343	$ 1	$ 38	$ 45	$ 69	$ 109	$ -	$ 1,809
Riverside	$ 56	$ 2,715	$ 3,766	$ 205	$ 2	$ 79	$ 1,243	$ 419	$ -	$ -	$ 8,484
Sherburne County	$ 312	$ 13,786	$ 14,449	$ 1,589	$ 16	$ 1,082	$ 1,863	$ 1,584	$ -	$ 0	$ 34,681
Sibley	$ 4	$ 188	$ 29	$ 77	$ 0	$ 9	$ 29	$ 2	$ -	$ -	$ 338
Wescott	$ 4	$ 821	$ 125	$ 141	$ 0	$ 44	$ 34	$ 1	$ -	$ 372	$ 1,541
Wilmarth	$ 24	$ 533	$ 565	$ 114	$ 1	$ 38	$ 45	$ 69	$ 254	$ -	$ 1,643
Total	**$ 1,097**	**$ 30,790**	**$ 33,285**	**$ 5,269**	**$ 36**	**$ 2,240**	**$ 11,403**	**$ 4,044**	**$ 3,928**	**$ 372**	**$ 92,464**

TABLE 4.3b
SCRAP METAL CREDITS BY STATION
(thousands of 2019 dollars)

Wind Farms (Complete Removal)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I	$ 748	$ 4,439	$ 1,126	$ 1,902	$ 604	$ 8,819
Border Winds Project	$ 557	$ 2,394	$ 845	$ 1,207	$ 453	$ 5,457
Courtenay	$ 747	$ 3,594	$ 1,126	$ 1,610	$ 604	$ 7,681
Foxtail	$ 715	$ 3,327	$ 845	$ 1,427	$ 453	$ 6,768
Grand Meadow	$ 489	$ 3,417	$ 755	$ 1,676	$ 405	$ 6,741
Lake Benton II	$ 410	$ 2,318	$ 552	$ 1,052	$ 297	$ 4,629
Nobles	$ 1,363	$ 5,253	$ 1,509	$ 3,363	$ 809	$ 12,298
Pleasant Valley	$ 789	$ 3,841	$ 1,126	$ 1,610	$ 604	$ 7,971
Total (Complete Removal)	**$ 5,819**	**$ 28,583**	**$ 7,885**	**$ 13,848**	**$ 4,228**	**$ 60,363**

TABLE 4.3c
SCRAP METAL CREDITS BY STATION
(thousands of 2019 dollars)

Wind Farms (Down to 48 inches below grade)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I (48 in.)	$ 85	$ 4,439	$ 25	$ 1,902	$ -	$ 6,449
Border Winds Project (48 in.)	$ 61	$ 2,394	$ 18	$ 1,207	$ -	$ 3,682
Courtenay (48 in.)	$ 84	$ 3,594	$ 25	$ 1,610	$ -	$ 5,312
Foxtail (48 in.)	$ 77	$ 3,327	$ 18	$ 1,427	$ -	$ 4,850
Grand Meadow (48 in.)	$ 71	$ 3,417	$ 16	$ 1,676	$ -	$ 5,181
Lake Benton II (48 in.)	$ 49	$ 2,318	$ 11	$ 1,052	$ -	$ 3,429
Nobles (48 in.)	$ 165	$ 5,253	$ 33	$ 3,363	$ -	$ 8,815
Pleasant Valley (48 in.)	$ 83	$ 3,841	$ 25	$ 1,610	$ -	$ 5,559
Total (Down 48 inch Removal)	**$ 676**	**$ 28,583**	**$ 171**	**$ 13,848**	**$ -**	**$ 43,277**

5. RESULTS

An estimate for dismantling each of the Xcel Energy fossil-fuel and wind farm generating stations in Minnesota and South Dakota was developed by applying the system and structures inventories against the associated unit cost factors and accounting for program support costs. A summary of each station's major cost categories is presented in Table 5.1 for the fossil stations, and in Table 5.2 for the wind farms.

5.1 FOSSIL STATIONS

Breakdowns of the major cost categories by unit and common facilities are provided in Tables 5.1a through 5.1q. Note that columns may not total due to rounding.

The following is an explanation of the contents of each line item in these tables:

Station Unit Rating (MWe) – This is the nominal electrical rating of each unit at the station. In Table 5.1 this represents the sum of all units on site.

Characterization / Temporary Services – The cost associated with performing a hazardous materials survey of the site prior to beginning field activities. Includes costs associated with de-energizing systems and isolation of the electrical systems in the buildings scheduled for dismantling. Costs for installing temporary services to support the dismantling are also included.

Worker Access – The cost associated with providing safe access to areas of the station being dismantled.

Pre-Demolition Cleaning (Boiler / Precipitator / Tanks) – The cost associated with cleaning coal-fired boilers and precipitators / baghouses, and associated flue-gas emission control systems. This line item also includes costs to clean acid and caustic storage tanks.

Asbestos / Lead Paint Remediation– The cost associated with remediating asbestos from the station prior to initiating dismantling activities. It should be noted that dismantling can proceed much more efficiently if asbestos containing materials have been removed. This line item also includes lead paint abatement from concrete surfaces in the buildings.

Equipment Removal – The cost associated with removing all station equipment (piping, valves, heat exchangers, tanks, electrical equipment, etc.).

Boiler(s) – The cost associated with removing the boiler.

Structures Demolition – The cost associated with demolishing the buildings and concrete foundations.

Backfill / Grade / Landscaping / Well Closure – The cost associated with backfilling below grade voids, and grading and landscaping the grounds to preclude erosion of soils. This line item also includes costs to seal groundwater monitoring wells.

Coal Yard Closure – The cost associated with removal and disposal of soil waste beneath the footprint of the coal field to a depth of 5 feet, and backfilling the void.

Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds / Ash Pond Dewatering – The cost associated with closure of the ponds on site, including placement of a cap on the pond(s) after backfilling.

Utility Management / Oversight – The staff directly assigned to manage the dismantling project, including planning, execution, oversight, and restoration.

Demolition Contractor Mgmt. / Super. / Safety Staff – The contractor's staff assigned to manage, engineer, and supervise the dismantling project, including site safety personnel.

Security – Personnel assigned to control access to the dismantling site.

Property Taxes – Not included in this estimate.

The following six items, grouped as Project Expenses, are calculated on a station basis, but are apportioned among the generating units on site by a ratio of the craft labor hours for each generating unit.

> *Shared Heavy Equipment / Operating Engineers* – The cost for renting / operating equipment in general use throughout the dismantling project (cranes, trucks, forklifts, front-end loaders, etc.).
>
> *Small Tool Allowance* – The cost for procuring small tools; this is consistent with R.S. Means 2019 Item 01 54 39.70-0100.
>
> *Utilities Allowance (Office Equip & Supplies / Telephone, Electric etc.)* – The cost for procuring utility services and office supplies in support of the field office for the utility management and demolition contractor staffs.

Permits – The cost of obtaining permits; this is consistent with R.S. Means 2019 Item 01 41 26.50.

Demolition Contractors Insurance – The cost of the demolition contractors insurance; the value is consistent with the R.S. Means 2019 Item 01 31 13.30, lines 0020, 0200, and 0600.

Demolition Contractors Fee – A fee applied to contractor activities; this represents the Contractors overhead and profit payment for the project and is consistent with R.S. Means 2019 Item 01 31 13.80 lines 0350, 0400 and 0450.

Contingency – The cost to cover expenses for unforeseen events that are likely to occur. The estimate assumes 25% (consistent with TLG's experience for similarly highly regulated activities in the nuclear industry) for the asbestos remediation work, and 15% for all other project activities, consistent with the R.S. Means 2019 Item 01 21 16.50 lines 0050 and 0100.

Scrap Credit – A credit to the project for the recovery of scrap metals. This corresponds to value shown in Table 4.3a through 4.3c.

The following is an explanation of the contents of each column in the 5.1 Tables:

Unit – Costs directly attributed to the physical work associated with dismantling a generating unit.

Common – Costs directly attributed to the physical work associated with dismantling facilities shared by more than one unit.

Station – Costs associated with supporting the physical dismantling work for a station.

Station Total – The summation of all Unit columns, plus Common and Station columns.

This study provides an estimate for dismantling under current requirements, based on present-day costs and available technology. As inputs to the cost model change over time, such as labor rates, equipment costs, scrap metal value, etc., this cost estimate should be reviewed and updated to reflect these changes.

TABLE 5.1

SUMMARY OF ACTIVITY COSTS – FOSSIL STATIONS
(2019 Dollars)

Activities (Costs)	Allen S . King	Angus Anson	Black Dog	Blue Lake	Granite City	Hennepin Island	High Bridge	Inver Hills	Key City	Maplewood	Minnesota Valley	Red Wing	Riverside	Sherburne County	Sibley	Wescott	Wilmarth	Fleet Totals
Station Rating (MWe)	511	386	526	545	0	14	606	371	0	0	0	18	590	2238	0	0	18	5778
Characterization / Temporary Services	351,606	297,606	907,818	330,606	239,606	237,606	456,606	263,439	239,606	125,803	519,212	471,212	1,035,818	1,136,818	125,803	159,404	471,000	7,369,573
Worker Access	630,789	-	793,518	-	-	-	-	-	-	-	187,086	123,388	-	1,988,310	-	-	123,388	3,846,477
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	1,080,300	240,000	-	-	-	-	-	342,500	-	-	500,900	515,600	526,800	3,243,150	-	-	515,600	6,964,850
Asbestos / Lead Paint Remediation	4,284,988	142,847	4,731,083	-	-	146,899	-	-	-	-	3,576,022	1,443,877	3,167,908	5,517,768	-	-	1,443,877	24,455,269
Equipment Removal	9,548,255	5,634,452	7,019,825	5,928,449	874,216	316,678	4,605,839	4,440,318	874,216	1,362,397	2,863,962	2,030,731	4,234,148	30,534,794	1,129,907	4,647,516	1,746,502	87,792,206
Boiler(s)	3,460,641	-	3,167,478	-	-	-	-	-	-	-	1,193,285	540,184	2,693,576	12,984,236	-	-	841,285	24,880,685
Structures Demolition	12,492,666	1,769,185	6,719,654	2,723,261	948,877	1,605,413	4,537,604	1,533,028	802,108	116,305	3,871,934	2,505,253	9,411,897	35,356,935	84,384	763,648	1,999,579	87,241,729
Backfill / Grade / Landscaping / Well Closure	3,697,788	1,133,560	2,767,357	1,529,390	383,922	790,474	1,742,979	1,343,018	243,348	161,005	1,432,771	1,079,539	2,498,203	9,987,445	164,731	756,289	780,770	30,492,588
Coal Yard Closure	10,718,358	-	-	-	-	-	-	-	-	-	-	-	-	8,264,365	-	-	-	18,982,723
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds / Ash Pond Dewatering	950,000	-	3,215,960	-	-	-	-	-	-	-	-	457,152	-	23,923,905	-	-	1,400,239	29,947,256
Utility Management / Oversight	3,027,199	945,676	3,459,078	1,580,835	784,321	778,453	1,618,917	1,333,298	781,800	871,780	1,979,405	1,119,169	3,482,165	3,860,869	839,852	1,003,663	1,119,169	28,585,648
Demolition Contractor Mgmt / Super. / Safety Staff	3,699,644	886,053	4,873,798	1,562,983	488,361	401,322	1,654,047	971,065	482,147	550,634	2,196,028	1,130,906	4,775,533	6,129,664	499,554	1,028,973	1,130,906	32,461,621
Security	776,195	197,940	960,031	197,940	115,679	145,241	208,222	131,103	114,394	194,084	298,195	272,488	965,867	1,135,113	177,374	227,502	272,488	6,389,856
Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Project Expenses																		
Shared Heavy Equipment / Operating Engineers	3,194,695	882,518	4,301,582	1,441,364	476,691	622,535	1,526,730	886,484	470,350	863,495	2,010,686	1,209,872	4,169,727	5,525,323	781,061	1,028,362	1,209,872	30,601,346
Small Tool Allowance	683,023	173,521	508,038	206,202	44,900	57,909	220,828	147,564	39,153	33,294	262,821	153,819	406,870	1,936,030	28,080	123,849	138,068	5,163,971
Utilities Allowance	52,508	30,400	64,945	30,400	17,766	22,306	31,979	20,135	17,569	29,807	45,797	41,849	65,339	76,789	27,241	34,940	41,849	651,617
Permits	685,566	139,877	488,388	171,908	43,429	52,514	184,708	124,344	39,606	40,534	233,256	146,292	412,323	1,832,569	35,510	106,787	148,037	4,885,649
Demolition Contractors Insurance	1,613,171	329,137	1,149,202	404,509	102,191	123,569	434,626	292,589	93,195	95,379	548,864	344,233	970,216	4,312,127	83,556	251,276	348,338	11,496,176
Demolition Contractors Fee	6,680,544	1,346,638	4,479,356	1,595,761	391,450	496,988	1,717,737	1,174,177	352,394	353,503	2,155,825	1,382,875	3,699,103	18,327,570	307,534	984,009	1,401,050	46,846,515
Sub-Total	67,627,939	14,149,409	49,607,111	17,703,605	4,911,409	5,797,909	18,940,824	13,003,063	4,549,886	4,798,021	23,876,048	14,968,441	42,515,494	176,073,780	4,284,587	11,116,217	15,132,016	489,055,758
Contingency	10,572,690	2,136,696	7,914,175	2,655,541	736,711	884,376	2,841,124	1,950,459	682,483	719,703	3,939,009	2,389,654	6,694,115	26,962,844	642,688	1,667,433	2,414,190	75,803,891
Project Total (before scrap credit)	78,200,628	16,286,105	57,521,286	20,359,146	5,648,121	6,682,285	21,781,947	14,953,523	5,232,369	5,517,724	27,815,058	17,358,094	49,209,609	203,036,624	4,927,275	12,783,650	17,546,206	564,859,649
Scrap Credit	(12,446,046)	(3,559,337)	(8,791,629)	(3,688,291)	(762,978)	(329,908)	(4,798,599)	(3,176,879)	(702,022)	(404,310)	(5,307,403)	(1,808,929)	(8,484,150)	(34,681,107)	(338,307)	(1,541,232)	(1,642,767)	(92,463,894)
Project Total	65,754,582	12,726,768	48,729,657	16,670,855	4,885,143	6,352,377	16,983,348	11,776,644	4,530,347	5,113,414	22,507,655	15,549,165	40,725,459	168,355,517	4,588,968	11,242,417	15,903,439	472,395,755

TABLE 5.1a

ALLEN S. KING STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Common	Station	Station Total
Allen S . King Unit Rating (MWe)	511			511
Characterization / Temporary Services	150,000	-	201,606	351,606
Worker Access	630,789	-		630,789
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	1,000,300	80,000		1,080,300
Asbestos / Lead Paint Remediation	4,284,988	-		4,284,988
Equipment Removal	7,865,365	1,682,890		9,548,255
Boiler(s)	3,460,641	-		3,460,641
Structures Demolition	10,016,294	2,476,372		12,492,666
Backfill / Grade / Landscaping / Well Closure	2,605,976	977,821	113,991	3,697,788
Coal Yard Closure		10,718,358		10,718,358
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds		950,000		950,000
Utility Management / Oversight			3,027,199	3,027,199
Demolition Contractor Management / Supervisory / Safety Staff			3,699,644	3,699,644
Security			776,195	776,195
Property Taxes	-	-	-	0
Project Expenses				
Shared Heavy Equipment / Operating Engineers			3,194,695	3,194,695
Small Tool Allowance	580,281	102,742	n/a	683,023
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)			52,508	52,508
Permits			685,566	685,566
Demolition Contractors Insurance			1,613,171	1,613,171
Demolition Contractors Fee			6,680,544	6,680,544
Sub-Total				67,627,939
Contingency				10,572,690
Project Total (before scrap credit)				78,200,628
Scrap Credit	(11,244,369)	(1,201,677)	-	(12,446,046)
Project Total				65,754,582

TABLE 5.1b

ANGUS ANSON STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Common	Station	Station Total
Angus Anson Unit Rating (MWe)	0	109	109	168			386
Characterization / Temporary Services	25,000	22,000	22,333	26,667	-	201,606	297,606
Pre-Demolition Cleaning (Tanks)	-	-	-	-	240,000		240,000
Lead Paint Remediation	142,847	-	-	-	-		142,847
Equipment Removal	2,642,304	589,684	592,643	1,471,114	338,707		5,634,452
Structures Demolition	1,044,734	158,683	161,649	343,728	60,391		1,769,185
Backfill / Grade / Landscaping / Well Closure	541,304	74,092	75,477	150,687	192,001	100,000	1,133,560
Utility Management / Oversight						945,676	945,676
Demolition Contractor Management / Supervisory / Safety Staff						886,053	886,053
Security						197,940	197,940
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						882,518	882,518
Small Tool Allowance	87,924	16,889	17,042	39,844	11,822	n/a	173,521
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						30,400	30,400
Permits						139,877	139,877
Demolition Contractors Insurance						329,137	329,137
Demolition Contractors Fee						1,346,638	1,346,638
Sub-Total							14,149,409
Contingency							2,136,696
Project Total (before scrap credit)							16,286,105
Scrap Credit	(1,394,645)	(547,154)	(554,872)	(980,393)	(82,273)	-	(3,559,337)
Project Total							12,726,768

TABLE 5.1c

BLACK DOG STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 2	Unit 3	Unit 5	Unit 6	Common	Station	Station Total
Black Dog Unit Rating (MWe)	117	0	181	228			526
Characterization / Temporary Services	64,000	67,000	79,000	93,000	-	604,818	907,818
Worker Access	387,123	406,395	-	-	-		793,518
Asbestos Remediation	1,956,422	1,969,760	-	800,000	4,902		4,731,083
Equipment Removal	2,289,715	2,297,438	1,366,958	981,902	83,813		7,019,825
Boiler(s)	1,750,299	1,417,179	-	-	-		3,167,478
Structures Demolition	823,953	1,315,352	1,535,212	2,081,747	963,391		6,719,654
Backfill / Grade / Landscaping / Well Closure	438,647	460,484	462,694	435,600	869,932	100,000	2,767,357
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds					3,215,960		3,215,960
Utility Management / Oversight						3,459,078	3,459,078
Demolition Contractor Management / Supervisory / Safety Staff						4,873,798	4,873,798
Security						960,031	960,031
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						4,301,582	4,301,582
Small Tool Allowance	154,203	158,672	68,877	87,845	38,441	n/a	508,038
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						64,945	64,945
Permits						488,388	488,388
Demolition Contractors Insurance						1,149,202	1,149,202
Demolition Contractors Fee						4,479,356	4,479,356
Sub-Total							49,607,111
Contingency							7,914,175
Project Total (before scrap credit)							57,521,286
Scrap Credit	(2,502,344)	(2,983,623)	(1,370,844)	(1,737,309)	(197,508)	-	(8,791,629)
Project Total							48,729,657

TABLE 5.1d

BLUE LAKE STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Unit 7	Unit 8	Common	Station	Station Total
Blue Lake Unit Rating (MWe)	50	50	46	48	174	177			545
Characterization / Temporary Services	12,250	12,250	12,250	12,250	40,000	40,000	-	201,606	330,606
Equipment Removal	566,731	566,731	566,731	566,731	1,472,140	1,472,140	717,247		5,928,449
Structures Demolition	234,043	203,009	203,009	203,009	461,241	461,241	957,708		2,723,261
Backfill / Grade / Landscaping	160,053	160,053	160,053	160,053	265,653	265,653	357,874	-	1,529,390
Utility Management / Oversight								1,580,835	1,580,835
Demolition Contractor Management / Supervisory / Safety Staff								1,562,983	1,562,983
Security								197,940	197,940
Property Taxes	-	-	-	-	-	-	-	-	0
Project Expenses									
Shared Heavy Equipment / Operating Engineers								1,441,364	1,441,364
Small Tool Allowance	19,462	18,841	18,841	18,841	44,781	44,781	40,657	n/a	206,202
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)								30,400	30,400
Permits								171,908	171,908
Demolition Contractors Insurance								404,509	404,509
Demolition Contractors Fee								1,595,761	1,595,761
Sub-Total									17,703,605
Contingency (excluding activities currently under contract)									2,655,541
Project Total (before scrap credit)									20,359,146
Scrap Credit	(473,687)	(415,070)	(415,070)	(415,070)	(862,163)	(862,163)	(245,069)	-	(3,688,291)
Project Total									16,670,855

TABLE 5.1e

GRANITE CITY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Common	Station	Station Total
Granite City Unit Rating (MWe)	0	0	0	0			0
Characterization / Temporary Services	9,500	9,500	9,500	9,500	-	201,606	239,606
Equipment Removal	218,554	218,554	218,554	218,554	-		874,216
Structures Demolition	142,423	142,423	142,423	142,423	379,183		948,877
Backfill / Grade / Landscaping	83,590	83,590	83,590	83,590	49,563	-	383,922
Utility Management / Oversight						784,321	784,321
Demolition Contractor Management / Supervisory / Safety Staff						488,361	488,361
Security						115,679	115,679
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						476,691	476,691
Small Tool Allowance	9,081	9,081	9,081	9,081	8,575	n/a	44,900
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						17,766	17,766
Permits						43,429	43,429
Demolition Contractors Insurance						102,191	102,191
Demolition Contractors Fee						391,450	391,450
Sub-Total							4,911,409
Contingency							736,711
Project Total (before scrap credit)							5,648,121
Scrap Credit	(159,623)	(159,623)	(159,623)	(159,623)	(124,486)	-	(762,978)
Project Total							4,885,143

TABLE 5.1f

HENNEPIN ISLAND STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1-5	Station	Station Total
Hennepin Island Unit Rating (MWe)	14		14
Characterization / Temporary Services	36,000	201,606	237,606
Lead Paint Remediation	146,899		146,899
Equipment Removal	316,678		316,678
Structures Demolition	1,605,413		1,605,413
Grade / Landscaping	790,474	-	790,474
Utility Management / Oversight		778,453	778,453
Demolition Contractor Management / Supervisory / Safety Staff		401,322	401,322
Security		145,241	145,241
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		622,535	622,535
Small Tool Allowance	57,909	n/a	57,909
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		22,306	22,306
Permits		52,514	52,514
Demolition Contractors Insurance		123,569	123,569
Demolition Contractors Fee		496,988	496,988
Sub-Total			5,797,909
Contingency			884,376
Project Total (before scrap credit)			6,682,285
Scrap Credit	(329,908)	-	(329,908)
Project Total			6,352,377

TABLE 5.1g

HIGH BRIDGE STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 7	Unit 8	Unit 9	Common	Station	Station Total
High Bridge Unit Rating (MWe)	185	185	236			606
Characterization / Temporary Services	79,000	79,000	97,000	-	201,606	456,606
Equipment Removal	1,393,993	1,393,993	1,452,905	364,947		4,605,839
Boiler(s)	-	-	-	-		0
Structures Demolition	1,109,013	1,109,013	1,777,707	541,872		4,537,604
Backfill / Grade / Landscaping / Well Closure	327,086	327,086	801,030	187,777	100,000	1,742,979
Utility Management / Oversight					1,618,917	1,618,917
Demolition Contractor Management / Supervisory / Safety Staff					1,654,047	1,654,047
Security					208,222	208,222
Property Taxes	-	-	-	-	-	0
Project Expenses						
Shared Heavy Equipment / Operating Engineers					1,526,730	1,526,730
Small Tool Allowance	58,182	58,182	82,573	21,892	n/a	220,828
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)					31,979	31,979
Permits					184,708	184,708
Demolition Contractors Insurance					434,626	434,626
Demolition Contractors Fee					1,717,737	1,717,737
Sub-Total						18,940,824
Contingency						2,841,124
Project Total (before scrap credit)						21,781,947
Scrap Credit	(1,418,437)	(1,418,437)	(1,846,014)	(115,711)	-	(4,798,599)
Project Total						16,983,348

TABLE 5.1h

INVER HILLS STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Common	Station	Station Total
Inver Hills Unit Rating (MWe)	62	62	62	62	61	62			371
Characterization / Temporary Services	8,833	8,833	8,833	8,833	8,833	8,833	8,833	201,606	263,439
Pre-Demolition Cleaning (Tanks)	-	-	-	-	-	-	342,500		342,500
Equipment Removal	696,798	696,798	696,798	696,798	696,798	696,798	259,531		4,440,318
Boiler(s)	-	-	-	-	-	-	-		0
Structures Demolition	232,167	232,167	232,167	232,167	232,167	232,167	140,023		1,533,028
Backfill / Grade / Landscaping	192,205	192,205	192,205	192,205	192,205	192,205	189,786	-	1,343,018
Utility Management / Oversight								1,333,298	1,333,298
Demolition Contractor Management / Supervisory / Safety Staff								971,065	971,065
Security								131,103	131,103
Property Taxes	-	-	-	-	-	-	-	-	0
Project Expenses									
Shared Heavy Equipment / Operating Engineers								886,484	886,484
Small Tool Allowance	22,600	22,600	22,600	22,600	22,600	22,600	11,963	n/a	147,564
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)								20,135	20,135
Permits								124,344	124,344
Demolition Contractors Insurance								292,589	292,589
Demolition Contractors Fee								1,174,177	1,174,177
Sub-Total									13,003,063
Contingency									1,950,459
Project Total (before scrap credit)									14,953,523
Scrap Credit	(517,223)	(517,223)	(517,223)	(517,223)	(517,223)	(517,223)	(73,541)	-	(3,176,879)
Project Total									11,776,644

TABLE 5.1i

KEY CITY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Common	Station	Station Total
Key City Unit Rating (MWe)	0	0	0	0			0
Characterization / Temporary Services	9,500	9,500	9,500	9,500	-	201,606	239,606
Equipment Removal	218,554	218,554	218,554	218,554	-		874,216
Structures Demolition	107,785	107,785	107,785	107,785	370,968		802,108
Backfill / Grade / Landscaping	50,591	50,591	50,591	50,591	40,982	-	243,348
Utility Management / Oversight						781,800	781,800
Demolition Contractor Management / Supervisory / Safety Staff						482,147	482,147
Security						114,394	114,394
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						470,350	470,350
Small Tool Allowance	7,729	7,729	7,729	7,729	8,239	n/a	39,153
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						17,569	17,569
Permits						39,606	39,606
Demolition Contractors Insurance						93,195	93,195
Demolition Contractors Fee						352,394	352,394
Sub-Total							4,549,886
Contingency							682,483
Project Total (before scrap credit)							5,232,369
Scrap Credit	(144,885)	(144,885)	(144,885)	(144,885)	(122,482)	-	(702,022)
Project Total							4,530,347

TABLE 5.1j

MAPLEWOOD GAS PLANT
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Station	Station Total
Maplewood Unit Rating (MWe)	0		0
Characterization / Temporary Services	25,000	100,803	125,803
Equipment Removal	1,362,397		1,362,397
Structures Demolition	116,305		116,305
Grade / Landscaping	161,005	-	161,005
Utility Management / Oversight		871,780	871,780
Demolition Contractor Management / Supervisory / Safety Staff		550,634	550,634
Security		194,084	194,084
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		863,495	863,495
Small Tool Allowance	33,294	n/a	33,294
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		29,807	29,807
Permits		40,534	40,534
Demolition Contractors Insurance		95,379	95,379
Demolition Contractors Fee		353,503	353,503
Sub-Total			4,798,021
Contingency			719,703
Project Total (before scrap credit)			5,517,724
Scrap Credit	(404,310)	-	(404,310)
Project Total			5,113,414

TABLE 5.1k

MINNESOTA VALLEY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	*Unit 1*	*Unit 2*	*Unit 3*	*Common*	*Station*	*Station Total*
Minnesota Valley Unit Rating (MWe)	0	0	0			0
Characterization / Temporary Services	34,000	34,000	48,000		403,212	519,212
Worker Access	-	-	187,086	-		187,086
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	166,967	166,967	166,967	-		500,900
Asbestos / Lead Paint Remediation	124,640	124,640	3,326,742	-		3,576,022
Equipment Removal	353,302	353,302	2,157,358	-		2,863,962
Boiler(s)	255,835	255,835	681,615	-		1,193,285
Structures Demolition	756,380	756,380	2,059,095	300,078		3,871,934
Backfill / Grade / Landscaping / Well Closure	415,645	415,645	396,692	104,790	100,000	1,432,771
Utility Management / Oversight					1,979,405	1,979,405
Demolition Contractor Management / Supervisory / Safety Staff					2,196,028	2,196,028
Security -					298,195	298,195
Property Taxes	-	-	-	-	-	0
Project Expenses						
Shared Heavy Equipment / Operating Engineers					2,010,686	2,010,686
Small Tool Allowance	38,796	38,796	177,132	8,097	n/a	262,821
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)					45,797	45,797
Permits					233,256	233,256
Demolition Contractors Insurance					548,864	548,864
Demolition Contractors Fee					2,155,825	2,155,825
Sub-Total						23,876,048
Contingency						3,939,009
Project Total (before scrap credit)						27,815,058
Scrap Credit	(1,232,488)	(1,232,488)	(2,840,688)	(1,738)	-	(5,307,403)
Project Total						22,507,655

TABLE 5.11

RED WING STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Common	Station	Station Total
Red Wing Unit Rating (MWe)	9	9			18
Characterization / Temporary Services	34,000	34,000	-	403,212	471,212
Worker Access	61,694	61,694	-		123,388
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	257,800	257,800	-		515,600
Asbestos / Lead Paint Remediation	721,939	721,939	-		1,443,877
Equipment Removal	780,906	780,906	468,918		2,030,731
Boiler(s)	270,092	270,092	-		540,184
Structures Demolition	731,187	731,187	1,042,878		2,505,253
Backfill / Grade / Landscaping / Well Closure	215,931	215,931	547,677	100,000	1,079,539
Ash Landfills / Ash Ponds & Landfills Inculding Evaporation Ponds			457,152		457,152
Utility Management / Oversight				1,119,169	1,119,169
Demolition Contractor Management / Supervisory / Safety Staff				1,130,906	1,130,906
Security				272,488	272,488
Property Taxes	-	-	-	-	0
Project Expenses					
Shared Heavy Equipment / Operating Engineers				1,209,872	1,209,872
Small Tool Allowance	56,315	56,315	41,189	n/a	153,819
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)				41,849	41,849
Permits				146,292	146,292
Demolition Contractors Insurance				344,233	344,233
Demolition Contractors Fee				1,382,875	1,382,875
Sub-Total					14,968,441
Contingency					2,389,654
Project Total (before scrap credit)					17,358,094
Scrap Credit	(662,363)	(662,363)	(484,203)	-	(1,808,929)
Project Total					15,549,165

TABLE 5.1m

RIVERSIDE STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 6 Boiler	Unit 7 Boiler	Unit 7 Turbine	Unit 8	Unit 9	Unit 10	Commom	Station	Station Total
Riverside Unit Rating (MWe)	44	44	160	0	171	171			590
Characterization / Temporary Services	48,000	48,000	80,000	93,000	81,000	81,000	-	604,818	1,035,818
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	170,600	170,600	-	170,600	-	-	15,000		526,800
Asbestos Remediation	1,025,353	1,025,353	-	1,117,201	-	-	-		3,167,908
Equipment Removal	-	-	987,364	473,484	1,377,540	1,377,540	18,220		4,234,148
Boiler(s)	875,389	875,389	-	942,798	-	-	-		2,693,576
Structures Demolition	1,041,505	1,041,505	574,865	2,627,561	952,584	952,584	2,221,292		9,411,897
Backfill / Grade / Landscaping / Well Closure	197,838	197,838	364,420	590,917	246,508	246,508	554,174	100,000	2,498,203
Utility Management / Oversight								3,482,165	3,482,165
Demolition Contractor Management / Supervisory / Safety Staff								4,775,533	4,775,533
Security								965,867	965,867
Property Taxes			-		-		-	-	0
Project Expenses									
Shared Heavy Equipment / Operating Engineers								4,169,727	4,169,727
Small Tool Allowance	63,762	63,762	40,133	116,899	33,220	33,220	55,874	n/a	406,870
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)								65,339	65,339
Permits								412,323	412,323
Demolition Contractors Insurance								970,216	970,216
Demolition Contractors Fee								3,699,103	3,699,103
Sub-Total									42,515,494
Contingency									6,694,115
Project Total (before scrap credit)									49,209,609
Scrap Credit	(1,202,298)	(1,202,298)	(1,141,914)	(2,432,111)	(1,179,549)	(1,179,549)	(146,430)	-	(8,484,150)
Project Total									40,725,459

TABLE 5.1n

SHERBURNE COUNTY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Common	Station	Station Total
Sherburne County Unit Rating (MWe)	680	682	876			2238
Characterization / Temporary Services	171,000	171,000	190,000	-	604,818	1,136,818
Worker Access	642,334	642,334	703,642	-		1,988,310
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	1,081,050	1,081,050	1,081,050	-		3,243,150
Asbestos Remediation	2,508,884	2,508,884	-	500,000		5,517,768
Equipment Removal	5,699,637	5,547,162	6,568,928	4,670,760		22,486,487
Boiler(s)	4,182,168	4,182,168	4,619,900	-		12,984,236
Turbine Generator & Condensor	609,899	609,899	686,634			1,906,432
Exhaust Gas Treatment Equipment and Structures	4,245,955	4,398,430	4,741,985			13,386,370
Structures Demolition	7,038,228	7,038,228	7,657,026	6,378,958		28,112,441
Backfill / Grade / Landscaping / Well Closure	1,656,105	1,656,105	1,814,172	4,761,063	100,000	9,987,445
Coal Yard Closure				8,264,365		8,264,365
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds / Ash Pond Dewatering			3,169,905	20,754,000		23,923,905
Utility Management / Oversight	1,079,289	1,079,289	1,208,276	494,016		3,860,869
Demolition Contractor Management / Supervisory / Safety Staff	1,713,520	1,713,520	1,918,305	784,319		6,129,664
Security	317,316	317,316	355,239	145,243		1,135,113
Property Taxes	-	-	-	-	-	0
Project Expenses						
Shared Heavy Equipment / Operating Engineers	1,544,579	1,544,579	1,729,174	706,991		5,525,323
Small Tool Allowance	535,084	535,084	539,646	326,216	n/a	1,936,030
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)					76,789	76,789
Permits					1,832,569	1,832,569
Demolition Contractors Insurance					4,312,127	4,312,127
Demolition Contractors Fee					18,327,570	18,327,570
Sub-Total						176,073,780
Contingency						26,962,844
Project Total (before scrap credit)						203,036,624
Scrap Credit	(9,982,485)	(9,982,485)	(12,096,244)	(2,619,893)	-	(34,681,107)
Project Total						168,355,517

TABLE 5.1o

SIBLEY GAS PLANT
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Station	Station Total
Sibley Unit Rating (MWe)	0		0
Characterization / Temporary Services	25,000	100,803	125,803
Equipment Removal	1,129,907		1,129,907
Structures Demolition	84,384		84,384
Grade / Landscaping	164,731	-	164,731
Utility Management / Oversight		839,852	839,852
Demolition Contractor Management / Supervisory / Safety Staff		499,554	499,554
Security		177,374	177,374
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		781,061	781,061
Small Tool Allowance	28,080	n/a	28,080
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		27,241	27,241
Permits		35,510	35,510
Demolition Contractors Insurance		83,556	83,556
Demolition Contractors Fee		307,534	307,534
Sub-Total			4,284,587
Contingency			642,688
Project Total (before scrap credit)			4,927,275
Scrap Credit	(338,307)	-	(338,307)
Project Total			4,588,968

TABLE 5.1p

WESCOTT GAS PLANT
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Station	Station Total
Wescott Unit Rating (MWe)	0		0
Characterization / Temporary Services	25,000	134,404	159,404
Equipment Removal	4,647,516		4,647,516
Structures Demolition	763,648		763,648
Grade / Landscaping	756,289	-	756,289
Utility Management / Oversight		1,003,663	1,003,663
Demolition Contractor Management / Supervisory / Safety Staff		1,028,973	1,028,973
Security		227,502	227,502
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		1,028,362	1,028,362
Small Tool Allowance	123,849	n/a	123,849
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		34,940	34,940
Permits		106,787	106,787
Demolition Contractors Insurance		251,276	251,276
Demolition Contractors Fee		984,009	984,009
Sub-Total			11,116,217
Contingency			1,667,433
Project Total (before scrap credit)			12,783,650
Scrap Credit	(1,541,232)	-	(1,541,232)
Project Total			11,242,417

TABLE 5.1q

WILMARTH STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Common	Station	Station Total
Wilmarth Unit Rating (MWe)	9	9			18
Characterization / Temporary Services	34,000	34,000	-	403,000	471,000
Worker Access	61,694	61,694	-		123,388
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	257,800	257,800	-		515,600
Asbestos / Lead Paint Remediation	721,939	721,939	-		1,443,877
Equipment Removal	780,906	780,906	184,689		1,746,502
Boiler(s)	420,643	420,643	-		841,285
Structures Demolition	626,917	626,917	745,744		1,999,579
Backfill / Grade / Landscaping / Well Closure	217,690	217,690	245,389	100,000	780,770
Ash Landfills			1,400,239		1,400,239
Utility Management / Oversight				1,119,169	1,119,169
Demolition Contractor Management / Supervisory / Safety Staff				1,130,906	1,130,906
Security				272,488	272,488
Property Taxes	-	-	-	-	0
Project Expenses					
Shared Heavy Equipment / Operating Engineers				1,209,872	1,209,872
Small Tool Allowance	57,276	57,276	23,516	n/a	138,068
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)				41,849	41,849
Permits				148,037	148,037
Demolition Contractors Insurance				348,338	348,338
Demolition Contractors Fee				1,401,050	1,401,050
Sub-Total					15,132,016
Contingency					2,414,190
Project Total (before scrap credit)					17,546,206
Scrap Credit	(737,645)	(737,645)	(167,478)	-	(1,642,767)
Project Total					15,903,439

5.2 WIND FARMS

An estimate for dismantling each of the Xcel Energy wind farm generating stations in Minnesota and North Dakota was developed by applying the system and structures inventories against the associated unit cost factors and accounting for program support costs. A summary of each wind farm's major cost categories is presented in Table 5.2. Breakdowns of the major cost categories by wind farm are provided in Tables 5.2a through 5.2p. Note that columns may not total due to rounding.

The following is an explanation of the contents of each line item in these tables:

<u>*TURBINE SITE REMOVAL*</u>

Dismantle Wind Turbine Generators – The cost associated with removal of the nacelle, hub, blades and tower. Also included is a percentage of the utility, DOC, and security staffing, miscellaneous expenses, and site characterization costs.

Haul Off of Materials (Trucking/Rail) – The cost associated with the transportation of the scrap material.

Foundation Removal – The cost of removal of the WTG concrete foundation or in the 48-inch scenario, the pedestal removal.

Crane Mobilization & Demobilization – All heavy equipment costs.

<u>*SITE CIVIL WORK REMOVAL*</u>

Balance of Site Civil Work Removals – The cost associated with backfilling below grade voids, and grading and landscaping the grounds to preclude erosion of soils. Also included is a percentage of the utility, DOC, and security staffing, miscellaneous expenses and site characterization costs.

<u>*COLLECTION SYSTEM REMOVAL*</u>

Remove Collection Cable, Remove Junction Boxes & Turbine Switchgears – The cost associated with excavation of the cable and back-fill of the trench. Also included is a percentage of the utility, DOC, and security staffing, miscellaneous expenses and site characterization costs.

Contingency (15%) - The cost to cover expenses for unforeseen events that are likely to occur.

Approximate scrap value of components – A credit to the project for the recovery of scrap metals. This corresponds to value shown in Table 4.3b through 4.3c.

TABLE 5.2

SUMMARY OF ACTIVITY COSTS – WIND FARMS
(2019 Dollars)

		Blazing Star I	Blazing Star I (48 in.)	Border Winds Project	Border Winds Project (48 in.)	Courtenay	Courtenay (48 in.)	Foxtail	Foxtail (48 in.)	Grand Meadow	Grand Meadow (48 in.)	Lake Benton II	Lake Benton II (48 in.)	Nobles	Nobles (48 in.)	Pleasant Valley	Pleasant Valley (48 in.)	Complete Removal	Removal (to to 48" depth)
ITEM	DESCRIPTION	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	AMOUNT	ITEM
1	TURBINE SITE REMOVAL																		
1a	Dismantle Wind Turbine Generators - Model 1	$1,392,653	$1,437,495	$11,136,713	$11,604,079	$13,597,829	$13,970,467	$993,756	$1,025,000	$10,279,573	$10,906,283	$804,060	$837,777	$18,641,078	$19,146,628	$15,900,269	$16,381,957	$72,745,929	$75,309,687
	Dismantle Wind Turbine Generators - Model 2	$12,625,322	$13,028,894	$0	$0	$0	$0	$9,723,737	$10,027,257	$0	$0	$6,529,184	$6,792,178	$0	$0	$0	$0	$28,878,242	$29,848,328
1b	Haul Off of Materials (Trucking/Rail)	$3,053,850	$2,643,300	$1,769,707	$1,462,533	$2,568,667	$2,158,116	$2,353,658	$1,987,602	$2,336,369	$2,072,402	$1,608,528	$1,391,969	$4,017,223	$3,339,613	$2,713,931	$2,285,819	$20,421,933	$17,341,355
1c	Foundation Removal - Model 1	$609,370	$73,272	$5,263,779	$585,008	$6,704,742	$801,686	$465,755	$54,629	$3,416,996	$525,128	$302,318	$37,728	$7,736,964	$1,012,965	$6,787,708	$792,287	$31,287,631	$3,882,702
	Foundation Removal - Model 2	$5,484,331	$659,444	$0	$0	$0	$0	$4,524,475	$530,685	$0	$0	$2,358,079	$294,280	$0	$0	$0	$0	$12,366,885	$1,484,409
1d	Crane Mobilization & Demobilization	$1,998,541	$1,903,425	$2,417,050	$2,283,888	$1,954,154	$1,846,356	$1,522,963	$1,453,212	$2,201,454	$2,138,044	$1,015,680	$977,633	$1,947,813	$1,871,720	$2,150,726	$2,061,951	$15,208,380	$14,536,230
	SUBTOTAL	**$25,164,068**	**$19,745,830**	**$20,587,249**	**$15,935,508**	**$24,825,391**	**$18,776,625**	**$19,584,343**	**$15,078,385**	**$18,234,392**	**$15,641,858**	**$12,617,848**	**$10,331,565**	**$32,343,078**	**$25,370,926**	**$27,552,633**	**$21,522,014**	**$180,909,001**	**$142,402,711**
2	SITE CIVIL WORK REMOVAL																		
2a	Balance of Site Civil Work Removals	$10,397,806	$10,084,299	$8,909,810	$8,622,688	$11,048,476	$10,695,312	$8,406,384	$8,171,092	$7,490,034	$7,343,033	$4,848,790	$4,759,976	$13,434,084	$13,038,736	$10,584,412	$10,237,618	$75,119,796	$72,952,756
	SUBTOTAL	**$10,397,806**	**$10,084,299**	**$8,909,810**	**$8,622,688**	**$11,048,476**	**$10,695,312**	**$8,406,384**	**$8,171,092**	**$7,490,034**	**$7,343,033**	**$4,848,790**	**$4,759,976**	**$13,434,084**	**$13,038,736**	**$10,584,412**	**$10,237,618**	**$75,119,796**	**$72,952,756**
3	COLLECTION SYSTEM REMOVAL																		
3a	Remove MV Collection Cable	$2,023,676	$408,958	$1,933,366	$397,071	$2,050,705	$407,251	$1,609,155	$324,523	$1,697,809	$366,382	$1,054,685	$221,763	$2,399,425	$479,044	$2,165,432	$438,778	$14,934,254	$3,043,769
3b	Remove Junction Boxes & Turbine Switchgears	$313,937	$31,394	$248,574	$24,857	$331,432	$33,143	$248,574	$24,857	$210,338	$21,034	$138,132	$13,813	$420,675	$42,068	$313,937	$31,394	$2,225,597	$222,560
	SUBTOTAL	**$2,337,613**	**$440,352**	**$2,181,939**	**$421,928**	**$2,382,137**	**$440,394**	**$1,857,729**	**$349,380**	**$1,908,147**	**$387,416**	**$1,192,817**	**$235,576**	**$2,820,100**	**$521,112**	**$2,479,368**	**$470,172**	**$17,159,851**	**$3,266,329**
	SITE SUBTOTAL	**$37,899,487**	**$30,270,481**	**$31,678,997**	**$24,980,125**	**$38,256,004**	**$29,912,331**	**$29,848,456**	**$23,598,856**	**$27,632,572**	**$23,372,307**	**$18,659,455**	**$15,327,118**	**$48,597,262**	**$38,930,775**	**$40,616,414**	**$32,229,804**	**$273,188,648**	**$218,621,796**
	CONTINGENGY (15%)	$5,684,923	$4,540,572	$4,751,850	$3,747,019	$5,738,401	$4,486,850	$4,477,268	$3,539,828	$4,144,886	$3,505,846	$2,798,918	$2,299,068	$7,289,589	$5,839,616	$6,092,462	$4,834,471	$40,978,297	$32,793,269
	Project Total (before scrap credit)	$43,584,410	$34,811,053	$36,430,847	$28,727,143	$43,994,405	$34,399,181	$34,325,724	$27,138,685	$31,777,458	$26,878,153	$21,458,374	$17,626,185	$55,886,851	$44,770,391	$46,708,876	$37,064,275	$314,166,945	$251,415,066
	APPROXIMATE SCRAP VALUE OF COMPONENTS	($8,818,650)	($6,449,499)	($5,456,601)	($3,681,527)	($7,680,961)	($5,311,810)	($6,767,995)	($4,850,452)	($6,741,282)	($5,180,812)	($4,628,964)	($3,429,286)	($12,298,196)	($8,815,111)	($7,970,541)	($5,558,899)	($60,363,190)	($43,277,397)
	TOTAL PRICE	**$34,765,760**	**$28,361,555**	**$30,974,246**	**$25,045,616**	**$36,313,443**	**$29,087,370**	**$27,557,729**	**$22,288,232**	**$25,036,176**	**$21,697,340**	**$16,829,410**	**$14,196,899**	**$43,588,656**	**$35,955,280**	**$38,738,336**	**$31,505,376**	**$253,803,755**	**$208,137,669**

Note: Model 1 and Model 2 designate the two Models of WTG at Blazing Star I, Foxtail, and Lake Benton II.

TABLE 5.2a
Blazing Star I Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT (Blazing Star I)
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	10	EA	$139,265	$1,392,653
	Dismantle Wind Turbine Generators - V120	90	EA	$140,281	$12,625,322
1b	Haul Off of Materials (Trucking/Rail)	100	EA	30,539	$3,053,850
1c	Foundation Removal - V110	10	EA	$60,937	$609,370
	Foundation Removal - V120	90	EA	$60,937	$5,484,331
1d	Crane Mobilization & Demobilization	1	LS	$1,998,541	$1,998,541
		SUBTOTAL			**$25,164,068**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,397,806	$10,397,806
		SUBTOTAL			**$10,397,806**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,023,676	$2,023,676
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$313,937	$313,937
		SUBTOTAL			**$2,337,613**
		SITE SUBTOTAL			**$37,899,487**
	CONTINGENGY (15%)				$5,684,923
	Project Total (before scrap credit)				$43,584,410
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($8,818,650)
TOTAL PRICE					**$34,765,760**

TABLE 5.2b
Blazing Star I Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Blazing Star I (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	10	EA	$143,749	$1,437,495
	Dismantle Wind Turbine Generators - V120	90	EA	$144,765	$13,028,894
1b	Haul Off of Materials (Trucking/Rail)	100	EA	26,433	$2,643,300
1c	Foundation Removal V110	10	EA	$7,327	$73,272
	Foundation Removal V120	90	EA	$7,327	$659,444
1d	Crane Mobilization & Demobilization	1	LS	$1,903,425	$1,903,425
		SUBTOTAL			**$19,745,830**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,084,299	$10,084,299
		SUBTOTAL			**$10,084,299**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$408,958	$408,958
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$31,394	$31,394
		SUBTOTAL			**$440,352**
		SITE SUBTOTAL			**$30,270,481**
	CONTINGENGY (15%)				$4,540,572
	Project Total (before scrap credit)				$34,811,053
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($6,449,499)
TOTAL PRICE					**$28,361,555**

TABLE 5.2c
Border Winds Project

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	Border Winds Project AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators V100.20	75	EA	$148,490	$11,136,713
1b	Haul Off of Materials (Trucking/Rail)	75	EA	23,596	$1,769,707
1c	Foundation Removal V100.20	75	EA	$70,184	$5,263,779
1d	Crane Mobilization & Demobilization	1	LS	$2,417,050	$2,417,050
		SUBTOTAL			$20,587,249
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,909,810	$8,909,810
		SUBTOTAL			$8,909,810
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,933,366	$1,933,366
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$248,574	$248,574
		SUBTOTAL			$2,181,939
		SITE SUBTOTAL			$31,678,997
	CONTINGENGY (15%)				$4,751,850
	Project Total (before scrap credit)				$36,430,847
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,456,601)
TOTAL PRICE					$30,974,246

TABLE 5.2d
Border Winds Project
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT (Border Winds Project (48 in.))
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	75	EA	$154,721	$11,604,079
1b	Haul Off of Materials (Trucking/Rail)	75	EA	19,500	$1,462,533
1c	Foundation Removal - V100-2.0	75	EA	$7,800	$585,008
1d	Crane Mobilization & Demobilization	1	LS	$2,283,888	$2,283,888
		SUBTOTAL			**$15,935,508**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,622,688	$8,622,688
		SUBTOTAL			**$8,622,688**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$397,071	$397,071
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$24,857	$24,857
		SUBTOTAL			**$421,928**
		SITE SUBTOTAL			**$24,980,125**
	CONTINGENGY (15%)				$3,747,019
	Project Total (before scrap credit)				$28,727,143
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($3,681,527)
TOTAL PRICE					**$25,045,616**

TABLE 5.2e
Courtenay Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Courtenay

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$135,978	$13,597,829
1b	Haul Off of Materials (Trucking/Rail)	100	EA	25,687	$2,568,667
1c	Foundation Removal - V100-2.0	100	EA	$67,047	$6,704,742
1d	Crane Mobilization & Demobilization	1	LS	$1,954,154	$1,954,154
		SUBTOTAL			$24,825,391
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$11,048,476	$11,048,476
		SUBTOTAL			$11,048,476
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,050,705	$2,050,705
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$331,432	$331,432
		SUBTOTAL			$2,382,137
		SITE SUBTOTAL			$38,256,004
	CONTINGENGY (15%)				$5,738,401
	Project Total (before scrap credit)				$43,994,405
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($7,680,961)
TOTAL PRICE					$36,313,443

TABLE 5.2f
Courtenay Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Courtenay (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$139,705	$13,970,467
1b	Haul Off of Materials (Trucking/Rail)	100	EA	21,581	$2,158,116
1c	Foundation Removal - V100-2.0	100	EA	$8,017	$801,686
1d	Crane Mobilization & Demobilization	1	LS	$1,846,356	$1,846,356
		SUBTOTAL			$18,776,625
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,695,312	$10,695,312
		SUBTOTAL			$10,695,312
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$407,251	$407,251
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$33,143	$33,143
		SUBTOTAL			$440,394
		SITE SUBTOTAL			$29,912,331
	CONTINGENGY (15%)				$4,486,850
	Project Total (before scrap credit)				$34,399,181
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,311,810)
TOTAL PRICE					$29,087,370

TABLE 5.2g
Foxtail Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

					Foxtail
ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	7	EA	$141,965	$993,756
	Dismantle Wind Turbine Generators - V120	68	EA	$142,996	$9,723,737
1b	Haul Off of Materials (Trucking/Rail)	75	EA	31,382	$2,353,658
1c	Foundation Removal - V110	7	EA	$66,536	$465,755
	Foundation Removal - V120	68	EA	$66,536	$4,524,475
1d	Crane Mobilization & Demobilization	1	LS	$1,522,963	$1,522,963
		SUBTOTAL			$19,584,343
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,406,384	$8,406,384
		SUBTOTAL			$8,406,384
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,609,155	$1,609,155
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$248,574	$248,574
		SUBTOTAL			$1,857,729
		SITE SUBTOTAL			$29,848,456
	CONTINGENGY (15%)				$4,477,268
	Project Total (before scrap credit)				$34,325,724
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($6,767,995)
TOTAL PRICE					$27,557,729

TABLE 5.2h
Foxtail Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Foxtail (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	7	EA	$146,429	$1,025,000
	Dismantle Wind Turbine Generators - V120	68	EA	$147,460	$10,027,257
1b	Haul Off of Materials (Trucking/Rail)	75	EA	26,501	$1,987,602
1c	Foundation Removal - V110	7	EA	$7,804	$54,629
	Foundation Removal - V120	68	EA	$7,804	$530,685
1d	Crane Mobilization & Demobilization	1	LS	$1,453,212	$1,453,212
		SUBTOTAL			$15,078,385
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,171,092	$8,171,092
		SUBTOTAL			$8,171,092
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$324,523	$324,523
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$24,857	$24,857
		SUBTOTAL			$349,380
		SITE SUBTOTAL			$23,598,856
	CONTINGENGY (15%)				$3,539,828
	Project Total (before scrap credit)				$27,138,685
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($4,850,452)
TOTAL PRICE					$22,288,232

TABLE 5.2i
Grand Meadow Wind

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Grand Meadow

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	67	EA	$153,426	$10,279,573
1b	Haul Off of Materials (Trucking/Rail)	67	EA	34,871	$2,336,369
1c	Foundation Removal - GE1.5-77	67	EA	$51,000	$3,416,996
1d	Crane Mobilization & Demobilization	1	LS	$2,201,454	$2,201,454
		SUBTOTAL			$18,234,392
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$7,490,034	$7,490,034
		SUBTOTAL			$7,490,034
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,697,809	$1,697,809
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$210,338	$210,338
		SUBTOTAL			$1,908,147
		SITE SUBTOTAL			$27,632,572
	CONTINGENGY (15%)				$4,144,886
	Project Total (before scrap credit)				$31,777,458
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($6,741,282)
TOTAL PRICE					$25,036,176

TABLE 5.2j
Grand Meadow Wind
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

					Grand Meadow (48 in.)
ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	67	EA	$162,780	$10,906,283
1b	Haul Off of Materials (Trucking/Rail)	67	EA	30,931	$2,072,402
1c	Foundation Removal - GE1.5-77	67	EA	$7,838	$525,128
1d	Crane Mobilization & Demobilization	1	LS	$2,138,044	$2,138,044
		SUBTOTAL			$15,641,858
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$7,343,033	$7,343,033
		SUBTOTAL			$7,343,033
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$366,382	$366,382
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$21,034	$21,034
		SUBTOTAL			$387,416
		SITE SUBTOTAL			$23,372,307
	CONTINGENGY (15%)				$3,505,846
	Project Total (before scrap credit)				$26,878,153
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,180,812)
TOTAL PRICE					$21,697,340

TABLE 5.2k
Lake Benton II Wind

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Lake Benton II

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE2.1-116	5	EA	$160,812	$804,060
	Dismantle Wind Turbine Generators - GE2.3-116	39	EA	$167,415	$6,529,184
1b	Haul Off of Materials (Trucking/Rail)	44	EA	36,557	$1,608,528
1c	Foundation Removal - GE2.1-116	5	EA	$60,464	$302,318
	Foundation Removal - GE2.3-116	39	EA	$60,464	$2,358,079
1d	Crane Mobilization & Demobilization	1	LS	$1,015,680	$1,015,680
		SUBTOTAL			**$12,617,848**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$4,848,790	$4,848,790
		SUBTOTAL			**$4,848,790**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,054,685	$1,054,685
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$138,132	$138,132
		SUBTOTAL			**$1,192,817**
		SITE SUBTOTAL			**$18,659,455**
	CONTINGENGY (15%)				$2,798,918
	Project Total (before scrap credit)				$21,458,374
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($4,628,964)
TOTAL PRICE					**$16,829,410**

TABLE 5.2l
Lake Benton II Wind
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Lake Benton II (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE2.1-116	5	EA	$167,555	$837,777
	Dismantle Wind Turbine Generators - GE2.3-116	39	EA	$174,158	$6,792,178
1b	Haul Off of Materials (Trucking/Rail)	44	EA	31,636	$1,391,969
1c	Foundation Removal - GE2.1-116	5	EA	$7,546	$37,728
	Foundation Removal - GE2.3-116	39	EA	$7,546	$294,280
1d	Crane Mobilization & Demobilization	1	LS	$977,633	$977,633
		SUBTOTAL			$10,331,565
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$4,759,976	$4,759,976
		SUBTOTAL			$4,759,976
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$221,763	$221,763
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$13,813	$13,813
		SUBTOTAL			$235,576
		SITE SUBTOTAL			$15,327,118
	CONTINGENGY (15%)				$2,299,068
	Project Total (before scrap credit)				$17,626,185
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($3,429,286)
TOTAL PRICE					$14,196,899

TABLE 5.2m
Nobles Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Nobles

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	134	EA	$139,113	$18,641,078
1b	Haul Off of Materials (Trucking/Rail)	134	EA	29,979	$4,017,223
1c	Foundation Removal - GE1.5-77	134	EA	$57,739	$7,736,964
1d	Crane Mobilization & Demobilization	1	LS	$1,947,813	$1,947,813
		SUBTOTAL			$32,343,078
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$13,434,084	$13,434,084
		SUBTOTAL			$13,434,084
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,399,425	$2,399,425
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$420,675	$420,675
		SUBTOTAL			$2,820,100
		SITE SUBTOTAL			$48,597,262
	CONTINGENGY (15%)				$7,289,589
	Project Total (before scrap credit)				$55,886,851
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($12,298,196)
TOTAL PRICE					$43,588,656

TABLE 5.2n
Nobles Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Nobles (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	134	EA	$142,885	$19,146,628
1b	Haul Off of Materials (Trucking/Rail)	134	EA	24,922	$3,339,613
1c	Foundation Removal - GE1.5-77	134	EA	$7,559	$1,012,965
1d	Crane Mobilization & Demobilization	1	LS	$1,871,720	$1,871,720
		SUBTOTAL			**$25,370,926**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$13,038,736	$13,038,736
		SUBTOTAL			**$13,038,736**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$479,044	$479,044
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$42,068	$42,068
		SUBTOTAL			**$521,112**
		SITE SUBTOTAL			**$38,930,775**
	CONTINGENGY (15%)				$5,839,616
	Project Total (before scrap credit)				$44,770,391
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($8,815,111)
TOTAL PRICE					**$35,955,280**

TABLE 5.2o
Pleasant Valley Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Pleasant Valley

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$159,003	$15,900,269
1b	Haul Off of Materials (Trucking/Rail)	100	EA	27,139	$2,713,931
1c	Foundation Removal - V100-2.0	100	EA	$67,877	$6,787,708
1d	Crane Mobilization & Demobilization	1	LS	$2,150,726	$2,150,726
		SUBTOTAL			**$27,552,633**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,584,412	$10,584,412
		SUBTOTAL			**$10,584,412**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,165,432	$2,165,432
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$313,937	$313,937
		SUBTOTAL			**$2,479,368**
		SITE SUBTOTAL			**$40,616,414**
	CONTINGENGY (15%)				$6,092,462
	Project Total (before scrap credit)				$46,708,876
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($7,970,541)
TOTAL PRICE					**$38,738,336**

TABLE 5.2p
Pleasant Valley Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT Pleasant Valley (48 in.)
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$163,820	$16,381,957
1b	Haul Off of Materials (Trucking/Rail)	100	EA	22,858	$2,285,819
1c	Foundation Removal - V100-2.0	100	EA	$7,923	$792,287
1d	Crane Mobilization & Demobilization	1	LS	$2,061,951	$2,061,951
			SUBTOTAL		**$21,522,014**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,237,618	$10,237,618
			SUBTOTAL		**$10,237,618**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$438,778	$438,778
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$31,394	$31,394
			SUBTOTAL		**$470,172**
			SITE SUBTOTAL		**$32,229,804**
	CONTINGENGY (15%)				$4,834,471
	Project Total (before scrap credit)				$37,064,275
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,558,899)
	TOTAL PRICE				**$31,505,376**

6. REFERENCES

1. E-mail dated November 18, 2019 from Roger P. Schluessel of Xcel Energy to Ben Stochmal at TLG Services; "Labor Rates"

2. E-mail dated December 11, 2019 from Roger P. Schluessel of Xcel Energy to Ben Stochmal at TLG Services; subject "Utility Salaries for 2019"

3. "Building Construction Cost Data 2019," Robert Snow Means Company, Inc., Kingston, Massachusetts [Open]

4. Recycler's World, Iron and Steel Recycling Section and Scrap Copper Recycling Section, U.S. Scrap Metal Index, January 1, 2015 to December 31, 2019 [Open]

5. T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986 [Open]

6. W.J. Manion and T.S. LaGuardia, "Decommissioning Handbook," U.S. Department of Energy, DOE/EV/10128-1, November 1980 [Open]

7. AACE International, Skills and Knowledge of Cost Engineering, 4th Edition, 1999 [Open]

8. 29 CFR Part 1926, Subpart T - Demolition , United States Department of Labor, 2019 https://www.osha.gov/doc/topics/demolition/index.html

APPENDIX A

SUMMARY OF STATION SYSTEM AND STRUCTURES INVENTORIES

TABLE A

SUMMARY OF STATION SYSTEMS AND STRUCTURES INVENTORIES

Index	System/Structure Inventory Data Point	Allen S . King	Angus Anson	Black Dog	Blue Lake	Granite City	Hennepin Island	High Bridge	Inver Hills	Key City	Maplewood	Minnesota Valley	Red Wing	Riverside	Sherburne County	Sibley	Wescott	Wilmarth
Station	Rating (Mwe)	511	386	409	545	0	14	606	371	0	0	0	178	502	2238	0	0	18
2	Piping 0.25 to 2 inches diameter, linear foot	79,850	31,521	11,835	20,178	1,501	-	24,690	3,268	1,501	-	492	4,919	24,046	233,790	-	-	4,919
3	Piping >2 to 4 inches diameter, linear foot	53,123	31,014	36,003	13,452	1,001	-	16,460	2,579	1,001	2,195	12,745	3,279	16,031	157,111	2,110	-	3,279
4	Piping >4 to 8 inches diameter, linear foot	35,133	14,009	24,870	10,357	3,138	-	11,173	6,964	3,138	1,120	6,427	2,186	10,687	103,907	520	5,585	2,186
5	Piping >8 to 14 inches diameter, linear foot	30,662	8,006	16,782	6,229	445	-	8,015	1,348	445	330	4,778	1,457	7,125	89,271	385	2,265	1,457
6	Piping >14 to 20 inches diameter, linear foot	7,208	2,614	7,217	4,259	148	-	5,377	1,139	148	90	2,484	794	4,750	26,401	75	20	794
7	Piping >20 to 36 inches diameter, linear foot	9,734	1,886	4,260	2,419	-	-	3,971	-	-	70	1,803	289	3,716	37,053	16	-	289
8	Piping >36 inches diameter, linear foot	5,335	898	3,074	1,796	-	-	2,420	-	-	-	17	173	2,126	15,991	-	60	173
9	Valves <2 inches	1,373	1,308	20	144	108	-	-	216	108	-	54	540	1,418	4,118	-	-	540
10	Valves >2 to 4 inches	935	1,660	1,869	672	72	-	698	174	72	330	402	360	698	2,805	346	-	360
11	Valves >4 to 8 inches	610	592	886	464	80	-	381	264	80	78	207	240	369	1,830	47	104	240
12	Valves >8 to 14 inches	1,519	272	531	142	24	-	159	62	24	44	134	120	123	1,115	54	35	120
13	Valves >14 to 20 inches	158	84	102	48	-	-	78	-	-	2	29	50	66	587	-	4	50
14	Valves >20 to 36 inches	128	22	31	24	-	-	36	-	-	-	14	16	36	476	-	-	16
15	Valves >36 inches	56	6	22	12	-	-	26	-	-	-	1	14	18	104	-	-	14
24	Pipe hangers for small bore piping, each	5,018	3,641	3,225	1,449	81	-	1,742	246	81	88	847	909	1,742	14,975	84	-	909
25	Pipe hangers for large bore piping, each	3,351	1,243	1,672	1,089	121	-	1,249	391	121	64	393	543	1,237	9,618	40	317	543
26	Pump and motor set < 300 pounds	77	17	62	72	16	-	13	108	16	6	32	38	13	507	3	7	38
27	Pumps, 300-1000 pound pump	23	16	18	12	-	-	13	-	-	-	4	8	13	73	-	7	8
28	Pumps, >1000-10,000 pound pump	14	5	15	-	-	-	2	-	-	-	4	11	2	44	-	-	11
29	Pumps, >10,000 pound pump	13	5	14	4	-	-	8	-	-	-	5	8	4	9	-	-	8
32	Pump motors, 300-1000 pound pump	23	32	18	12	-	-	13	-	-	-	4	8	13	28	-	7	8
33	Pump motors, >1000-10,000 pound pump	13	5	12	-	-	-	3	-	-	-	4	11	3	68	2	-	11
34	Pump motors, >10,000 pound pump	13	5	14	4	-	-	8	-	-	-	5	4	4	18	-	-	4
37	Turbine-driven pumps > 10,000 pounds	1	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-
38	Main turbine-generator (pounds per MW(e) input)	1	1	2	-	-	-	1	-	-	-	3	2	2	3	-	-	2
39	Heat exchanger <3000 pound	16	12	30	101	-	-	6	210	-	-	15	12	6	60	-	-	12
40	Heat exchanger >3000 pound	-	27	12	48	-	-	5	96	-	-	7	14	5	21	-	-	14
41	Feedwater heater/deaerator	9	6	25	2	-	-	2	-	-	-	7	12	2	31	-	-	12
49	Main condenser (pounds per MW(e) input)	1	1	2	-	-	-	1	-	-	-	3	2	1	3	-	-	2
51	Tanks, <300 gallons, filters, and ion exchangers	38	33	41	20	16	3	10	34	16	5	39	12	10	66	28	25	12
52	Tanks, 300-3000 gallons	12	32	29	4	12	-	11	8	12	6	7	2	6	132	9	4	2
53	Tanks, >3000 gallons, square foot surface	27,566	75,184	4,933	62,690	2,847	-	23,259	7,069	2,847	101,764	87,790	33,585	1,859	162,458	81,889	374,754	6,871
54	Electrical equipment, <300 pound	742	686	881	647	420	54	150	846	420	21	222	322	128	6,686	36	-	322
55	Electrical equipment, 300-1000 pound	144	296	500	350	40	16	289	184	40	17	51	18	280	936	13	15	18
56	Electrical equipment, 1000-10,000 pound	122	190	203	280	80	25	207	175	80	7	39	56	201	122	2	32	56
57	Electrical equipment, >10,000 pound	19	99	18	128	28	36	16	168	28	5	4	16	16	30	3	5	16
59	Electrical transformers < 30 tons	3	13	22	14	2	-	4	18	2	2	10	-	4	6	2	1	-
60	Electrical transformers > 30 tons	3	9	6	12	2	-	5	12	2	-	4	2	5	3	-	-	2
61	Standby diesel-generator, <100 kW	-	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Standby diesel-generator, 100 kW to 1 MW	-	-	-	-	8	-	-	-	8	-	-	-	-	-	-	-	-
63	Standby diesel-generator, >1 MW	2	-	-	-	4	-	-	-	4	-	-	-	2	5	-	-	-
64	Fluorescent light fixture	200	250	450	180	80	10	200	100	80	30	163	38	150	498	30	24	38
65	Incandescent light fixture	1,564	288	1,000	180	120	16	200	170	120	30	327	258	150	4,060	30	24	258
66	Electrical cable tray, linear foot	27,803	5,512	13,091	5,651	1,730	250	10,276	-	1,730	-	2,107	1,364	9,206	166,291	-	820	1,364
67	Electrical conduit, linear foot	41,992	7,922	45,448	8,631	2,471	4,790	13,688	-	2,471	2,060	18,605	8,658	11,905	119,404	2,000	8,500	8,658
69	Mechanical equipment, <300 pound	788	288	670	52	44	5	31	78	44	8	258	360	21	2,388	6	48	360
70	Mechanical equipment, 300-1000 pound	198	312	290	812	64	8	274	30	64	-	77	14	274	457	21	9	14
71	Mechanical equipment, 1000-10,000 pound	204	60	38	127	-	38	59	1,000	-	3	23	60	44	516	17	28	60
72	Mechanical equipment, >10,000 pound	68	160	106	238	60	26	141	219	60	20	5	45	103	90	8	62	45

TABLE A

SUMMARY OF SYSTEMS AND STRUCTURES INVENTORIES
(Continued)

Index	System/Structure Inventory Data Point	Allen S . King	Angus Anson	Black Dog	Blue Lake	Granite City	Hennepin Island	High Bridge	Inver Hills	Key City	Maplewood	Minnesota Valley	Red Wing	Riverside	Sherburne County	Sibley	Wescott	Wilmarth
Station	Rating (Mwe)	511	386	409	545	0	14	606	371	0	0	0	178	502	2238	0	0	18
76	HVAC equipment, <300 pound	108	14	-	16	-	-	-	24	-	-	4	10	-	328	-	-	10
77	HVAC equipment, 300-1000 pound	-	22	4	-	-	-	36	-	-	-	-	-	24	107	-	-	-
78	HVAC equipment, 1000-10,000 pound	-	5	-	-	-	-	14	-	-	-	2	4	10	6	-	-	4
79	HVAC equipment, >10,000 pound	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-
82	HVAC ductwork, pound	119,977	10,000	273,680	-	-	8,175	142,100	-	-	-	96,406	18,295	38,202	439,440	-	-	18,295
201	Standard reinforced concrete, cubic yard	24,015	6,662	22,278	14,027	3,806	2,006	18,008	14,800	1,903	770	7,390	9,138	23,366	89,076	591	7,914	5,248
202	Grade slab concrete, cubic yard	10,800	1,329	8,959	1,176	906	-	372	1,384	906	-	676	474	3,551	-	-	-	474
206	Heavily rein concrete w/#9 rebar, cubic yard	7,824	1,110	7,007	-	-	-	-	-	-	-	3,788	1,793	3,035	22,775	-	-	1,793
222	Hollow masonry block wall, cubic yard	-	1,103	374	58	-	-	425	-	-	-	-	-	2,219	-	-	-	109
224	Solid masonry block wall, cubic yard	3,788	-	4,114	-	-	458	-	-	-	-	8,809	663	3,011	14,335	-	-	663
229	Backfill of below grade voids, cubic yard	29,218	11,074	14,043	12,493	2,170	20,000	19,394	6,898	1,308	-	32,816	17,556	12,325	-	-	-	20,531
230	Excavation of clean material, cubic yard	8,747	-	13,387	-	-	-	-	-	-	-	7,307	5,760	18,507	34,560	-	-	5,760
235	Building by volume, cubic foot	5,117,058	229,493	35,076	970,228	189,562	-	318,816	247,411	189,562	159,000	155,740	321,500	597,793	9,863,100	107,000	390,842	321,500
236	Building metal siding, square foot	217,256	42,789	56,780	19,901	37,278	-	108,748	15,564	37,278	-	73,964	32,498	93,913	669,467	-	-	32,498
242	Standard asphalt roofing, square foot	47,897	22,500	32,544	-	-	9,375	110,000	-	-	-	23,588	9,129	119,469	237,266	-	-	9,129
245	Placement of cofferdam, linear foot	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
248	Lead paint removal from concrete surfaces, square foo	373,064	54,000	-	-	-	54,150	-	-	-	-	135,495	54,337	-	-	-	-	54,337
253	Overhead cranes/monorails < 10 ton capacity, each	14	5	2	-	-	-	-	-	-	-	-	1	-	136	-	-	1
255	Overhead cranes/monorails >10 - 50 ton capacity, each	6	2	-	4	-	1	5	-	-	-	2	2	7	21	-	1	2
258	Gantry cranes > 50 ton capacity, each	1	-	-	1	-	-	1	-	-	-	-	-	5	6	-	-	-
260	Structural steel, pounds	24,541,699	2,731,615	13,947,804	1,748,139	310,648	299,854	6,981,323	662,931	310,648	12,000	6,612,141	2,429,526	17,879,987	83,653,565	10,000	77,000	2,429,526
262	Steel floor grating, square foot	161,222	16,242	43,412	7,410	2,673	900	18,797	-	2,673	-	12,083	30,386	56,169	578,353	-	-	30,386
268	Placement of scaffolding in clean areas, square foot	66,680	-	83,881	-	-	-	-	-	-	-	19,777	13,043	-	210,181	-	-	13,043
270	Landscaping with topsoil, acre	3	4	4	1	0	2	1.9	2	0	3	1	4	3	33	2	4	2
271	Landscaping w/o topsoil, acre	29	4	5	8	2	-	4	9	2	3	7	3	8	239	2	4	4
272	Chain link fencing, linear foot	3,372	6,800	3,000	2,880	995	550	3,144	2,800	995	2,460	3,859	8,372	5,016	20,000	3,680	3,450	995
273	Railroad track, linear foot	3,000	-	3,600	-	-	-	-	-	-	-	-	-	-	24,000	-	-	-
274	Asphalt pavement, square foot	220,880	91,000	122,500	78,300	12,000	17,650	75,171	51,000	12,000	17,750	38,225	-	128,241	801,500	45,625	62,700	52,000
293	Carbon steel plate 3/8 inch thick, square foot	-	8,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
294	Carbon steel plate 1/2 inch thick, square foot	66,630	7,388	36,515	14,776	75,398	12,441	14,550	-	75,398	-	6,959	17,695	78,517	219,533	-	-	17,695
359	Steam drum removal (fossil)	1	3	5	6	-	-	6	-	-	-	3	2	9	6	-	-	2
360	Water drum removal (fossil)	-	-	-	-	-	-	-	-	-	-	4	4	-	12	-	-	4
361	Upper/lower waterwall headers (fossil)	26	-	22	-	-	-	-	-	-	-	14	6	27	72	-	-	6
362	Top sup boiler waterwall (8'x8' section), inches cut	138,902	-	75,985	-	-	-	-	-	-	-	45,627	13,392	128,711	470,566	-	-	13,392
369	Boiler convective superheaater platens	307	-	356	-	-	-	-	-	-	-	256	116	459	1,344	-	-	116
370	Boiler radiant superheater platens	-	-	-	-	-	-	-	-	-	-	-	-	-	156	-	-	-
371	Boiler reheat platens	140	-	180	-	-	-	-	-	-	-	-	-	90	666	-	-	-
372	Boiler economizer platens	420	-	169	-	-	-	-	-	-	-	39	-	163	1,344	-	-	-
374	Stationary soot blowers	98	-	64	-	-	-	-	-	-	-	21	-	32	315	-	-	-
375	Retractable soot blowers	70	-	36	-	-	-	-	-	-	-	7	16	18	144	-	-	16
376	Process ductwork (8'x8' section), inches cut	757,268	321,019	1,009,405	625,433	54,416	-	446,315	307,617	54,416	-	470,306	61,481	1,009,280	3,392,767	-	-	61,481
378	Non-asbestos insulated regenerative air preheaters	4	-	9	-	-	-	-	-	-	-	8	8	4	13	-	-	8
380	Non-asbestos insulated recuperative air preheaters	-	-	-	-	-	-	-	-	-	-	4	-	8	-	-	-	-
382	Induced, forced, primary draft fans	9	-	11	-	-	-	-	-	-	-	4	4	-	42	-	-	4
383	Coal car dumpers	1	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-
384	Conveyors	5,528	-	-	-	-	-	-	-	-	-	-	625	-	5,000	-	-	625
385	Transfer Towers	100,500	-	-	-	-	-	-	-	-	-	-	-	-	201,000	-	-	-
386	Stacker-reclaimers	1	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-
389	Ball mills	12	-	8	-	-	-	-	-	-	-	4	-	-	43	-	-	-
390	Coal feeders	120	-	122	-	-	-	-	-	-	-	40	86	-	1,019	-	-	86

TABLE A
SUMMARY OF STATION SYSTEMS AND STRUCTURES INVENTORIES

WIND FARMS ONLY

Index	System/Structure Inventory Data Point	Blazing Star I	Blazing Star I (48 in.)	Border Winds Project	Border Winds Project (48 in.)	Courtenay	Courtenay (48 in.)	Foxtail	Foxtail (48 in.)	Grand Meadow	Grand Meadow (48 in.)	Lake Benton II	Lake Benton II (48 in.)	Nobles	Nobles (48 in.)	Pleasant Valley	Pleasant Valley (48 in.)
Station	Rating (Mwe)	200	200	148	148	190	190	150	150	99	99	99	99	197	197	196	196
56	Electrical equipment, 1000-10,000 pound	100	100	75	75	100	100	75	75	67	67	44	44	134	134	100	100
57	Electrical equipment, >10,000 pound	300	300	225	225	300	300	225	225	134	134	132	132	268	268	300	300
67	Electrical conduit, linear foot	1,731,165	-	1,298,374	-	1,731,165	-	1,298,374	-	1,159,881	-	513184	0	2,319,761	-	1,731,165	-
72	Mechanical equipment, >10,000 pound	1,550	1,550	1,163	1,163	1,550	1,550	1,163	1,163	1,039	1,039	770	770	2211	2,211	1650	1650
201	Standard reinforced concrete, cubic yard	36,220	4,067	28,822	3,125	36,182	4,029	28,397	3,086	18,865	2,765	15854	1908	43,432	5,336	38,082	3,997
229	Backfill of below grade voids, cubic yard	207,034	174,881	156,858	131,161	207,034	174,881	156,471	131,161	133,270	117,170	90893	76948	272,437	234,341	208,965	174,881
230	Excavation of clean material, cubic yard	333,101	187,310	249,826	140,483	333,101	187,310	249,826	140,483	223,178	125,498	146565	82416	446,356	250,996	333,101	187,310
235	Building by volume, cubic foot	132,000	132,000	132,000	132,000	108,000	108,000	108,000	108,000	95,625	95,625	102,000	102,000	123,930	123,930.00	88,560	88,560
270	Landscaping with topsoil, acre	71	71	53	53	71	71	53	53	47	47	31	31	95	95	71	71
271	Landscaping w/o topsoil, acre	4	4	3	3	4	4	3	3	3	3	3	3	3	3	3	3
294	Carbon steel plate 1/2 inch thick, square foo	892,716	892,716	588,123	588,123	784,164	784,164	669,644	669,644	658,346	658,346	524316	524316	1,316,693	1,316,692.58	1,156,983	1,156,983

APPENDIX B

UNIT COST FACTOR DEVELOPMENT

APPENDIX B

UNIT COST FACTOR DEVELOPMENT
(Using Minnesota-based labor rates)

Example: Unit Factor for Removal of Heat Exchanger < 3,000 pounds

1. SCOPE

Heat exchangers weighing < 3,000 lb. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the laydown area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration	Critical Duration
a	Remove insulation	20	(b)
b	Mount pipe cutters	60	60
c	Disconnect inlet and outlet lines	60	60
d	Rig for removal	30	30
e	Unbolt from mounts	30	30
f	Remove, send to packing area	60	60
	Totals (Activity/Critical)	260	240

Duration adjustment(s):	
+ Work break adjustment (8.33 % of productive duration)	20
Total work duration (minutes)	260

***** Total duration = 4.333 hours *****

3. LABOR REQUIRED

Crew	Number	Duration (hr)	Rate ($/hr)	Cost ($)
Laborers	3.0	4.333	60.80	790.34
Craftsmen	2.0	4.333	71.33	618.15
Foreman	1.0	4.333	73.44	318.22
General Foreman	0.25	4.333	74.44	80.64
Fire Watch	0.05	4.333	60.80	13.17
Total labor cost				1,820.52

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	none
Consumables/Materials Costs	
Gas torch consumables 1 @ $19.93/hr x 1 hr {1}	19.93
Subtotal cost of equipment and materials	19.93
Overhead & profit on equipment and materials @ 16.88%	3.36
Total costs, equipment & material	23.29
TOTAL COST Removal of heat exchanger <3000 pound:	**1,843.81**
Total labor cost:	1,820.52
Total equipment/material costs:	23.29
Total craft labor man-hours required per unit:	27.298

5. NOTES AND REFERENCES

- Durations are shown in minutes. The integrated duration accounts for those activities that can be performed in conjunction with other activities, indicated by the alpha designator of the concurrent activity. This results in an overall decrease in the sequenced duration.

- Work difficulty factors were developed in conjunction with the AIF program to standardize decommissioning cost studies and are delineated in the "Guidelines" study (Reference 2, Vol. 1, Chapter 5).

- References for equipment and consumables costs:

    1. R.S. Means (2019) Division 01 54 33, Section 40-6360 Page 736

APPENDIX C

UNIT COST FACTOR LISTING

TABLE C-1

UNIT COST FACTOR LISTING
Minnesota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors				Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
2	Piping 0.25 to 2 inches diameter, linear foot	6.97	6.89	0.1	-	4	-	0.5	-	-	-	-
3	Piping >2 to 4 inches diameter, linear foot	9.79	9.68	0.2	-	7	-	0.9	-	-	0.4	-
4	Piping >4 to 8 inches diameter, linear foot	18.72	18.56	0.3	-	22	-	-	-	-	-	-
5	Piping >8 to 14 inches diameter, linear foot	36.53	36.34	0.6	-	57	-	-	-	-	-	-
6	Piping >14 to 20 inches diameter, linear foot	47.51	46.93	0.7	-	-	120	-	-	-	-	-
7	Piping >20 to 36 inches diameter, linear foot	69.90	69.13	1.1	-	-	221	-	-	-	-	-
8	Piping >36 inches diameter, linear foot	83.05	82.27	1.3	-	-	417	-	-	-	-	-
9	Valves <2 inches	133.87	133.10	2.0	-	-	-	-	-	-	-	-
10	Valves >2 to 4 inches	124.03	122.86	1.9	75	-	-	8.8	-	-	4.4	-
11	Valves >4 to 8 inches	187.18	185.61	2.8	510	-	-	-	-	-	-	-
12	Valves >8 to 14 inches	365.29	363.36	5.6	1,066	-	-	-	-	-	-	-
13	Valves >14 to 20 inches	475.15	469.33	7.3	-	-	2,040	-	-	-	-	-
14	Valves >20 to 36 inches	699.04	691.28	10.7	-	-	3,334	-	-	-	-	-
15	Valves >36 inches	830.45	822.69	12.7	-	-	11,535	-	-	-	-	-
24	Pipe hangers for small bore piping, each	43.43	37.61	0.6	-	10	-	-	-	-	-	-
25	Pipe hangers for large bore piping, each	156.79	145.14	2.3	-	50	-	-	-	-	-	-
26	Pump and motor set < 300 pounds	316.32	306.61	4.7	-	-	50	12.5	-	-	-	62.3
27	Pumps, 300-1000 pound pump	866.84	851.31	12.7	293	-	49	48.9	-	-	-	-
28	Pumps, >1000-10,000 pound pump	3,438.05	3,414.76	51.3	2,834	-	472	472.3	-	-	-	-
29	Pumps, >10,000 pound pump	6,651.40	6,581.52	98.9	43,693	-	7,282	7,282.1	-	-	-	-
32	Pump motors, 300-1000 pound pump	362.10	362.10	5.4	-	-	-	-	-	-	-	307.8
33	Pump motors, >1000-10,000 pound pump	1,428.02	1,428.02	21.5	-	-	-	-	-	-	-	3,531.6
34	Pump motors, >10,000 pound pump	3,213.05	3,213.05	48.3	-	-	-	-	-	-	-	42,324.5
37	Turbine-driven pumps > 10,000 pounds	8,904.73	8,827.09	132.7	20,000	-	20,000	-	-	-	-	-
38	Main turbine-generator (pounds per MW(e) input)	208,434.81	206,943.98	3,042.0	-	-	851,500	-	-	-	-	851,500.0
39	Heat exchanger <3000 pound	1,843.81	1,820.52	27.3	-	-	416	623.4	-	-	-	-
40	Heat exchanger >3000 pound	4,644.67	4,551.49	68.3	-	-	5,599	8,397.9	-	-	-	-
41	Feedwater heater/deaerator	13,109.71	12,923.36	194.2	-	-	12,000	18,000.0	-	-	-	-
49	Main condenser (pounds per MW(e) input)	573,864.75	553,556.38	8,243.6	149,400	-	149,400	199,200.0	-	-	-	-
51	Tanks, <300 gallons, filters, and ion exchangers	406.82	395.17	6.0	-	-	401	401.2	-	-	-	-
52	Tanks, 300-3000 gallons	1,281.67	1,258.38	19.1	-	-	2,700	300.0	-	-	-	-
53	Tanks, >3000 gallons, square foot surface	10.64	10.35	0.2	-	21	-	-	-	-	-	-
54	Electrical equipment, <300 pound	171.33	171.33	2.6	-	-	56	-	-	-	2.9	-
55	Electrical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	624	-	-	-	32.8	-

TABLE C-1 (continued)

UNIT COST FACTOR LISTING
Minnesota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors				Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
56	Electrical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	2,212	-	-	-	116.4	-
57	Electrical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	19,950	-	-	-	1,050.0	-
59	Electrical transformers < 30 tons	1,930.13	1,930.13	28.4	-	-	11,250	-	-	-	3,750.0	-
60	Electrical transformers > 30 tons	5,558.44	5,558.44	81.9	-	-	375,000	-	-	-	125,000.0	-
61	Standby diesel-generator, <100 kW	1,971.46	1,971.46	29.1	2,340	-	-	-	-	-	-	260.0
62	Standby diesel-generator, 100 kW to 1 MW	4,400.42	4,400.42	64.8	9,450	-	-	-	-	-	-	1,050.0
63	Standby diesel-generator, >1 MW	9,109.78	9,109.78	134.2	47,250	-	-	-	-	-	-	5,250.0
64	Fluorescent light fixture	71.90	71.90	1.1	-	-	-	-	-	-	-	-
65	Incandescent light fixture	36.05	36.05	0.6	-	-	-	-	-	-	-	-
66	Electrical cable tray, linear foot	16.12	15.73	0.2	-	-	-	-	6.6	6.6	-	-
67	Electrical conduit, linear foot	7.04	6.85	0.1	-	-	-	-	3.4	3.4	-	-
69	Mechanical equipment, <300 pound	171.33	171.33	2.6	-	-	127	-	-	-	-	-
70	Mechanical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	641	-	-	-	-	-
71	Mechanical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	4,184	-	-	-	-	-
72	Mechanical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	11,938	-	-	-	-	-
76	HVAC equipment, <300 pound	207.18	207.18	3.1	-	-	184	-	-	-	-	-
77	HVAC equipment, 300-1000 pound	708.37	708.37	10.6	-	-	643	-	-	-	-	-
78	HVAC equipment, 1000-10,000 pound	1,411.80	1,411.80	21.0	-	-	3,813	-	-	-	-	-
79	HVAC equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	19,391	-	-	-	-	-
82	HVAC ductwork, pound	0.68	0.68	0.0	-	-	-	-	1.0	-	-	-
201	Standard reinforced concrete, cubic yard	77.12	26.84	0.4	-	183	-	-	-	-	-	-
202	Grade slab concrete, cubic yard	87.72	30.65	0.5	-	183	-	-	-	-	-	-
206	Heavily rein concrete w/#9 rebar, cubic yard	111.41	39.28	0.6	-	730	-	-	-	-	-	-
222	Hollow masonry block wall, cubic yard	26.45	10.27	0.1	-	66	-	-	-	-	-	-
224	Solid masonry block wall, cubic yard	26.45	10.27	0.1	-	66	-	-	-	-	-	-
229	Backfill of below grade voids, cubic yard	31.11	4.21	0.1	-	-	-	-	-	-	-	-
230	Excavation of clean material, cubic yard	3.23	1.49	0.0	-	-	-	-	-	-	-	-
235	Building by volume, cubic foot	0.34	0.21	-	-	-	1	-	-	-	-	-
236	Building metal siding, square foot	1.74	1.28	0.0	-	-	-	-	2.4	-	-	-
242	Standard asphalt roofing, square foot	3.01	3.01	0.1	-	-	-	-	-	-	-	-
243	Galbestos panels, square foot	2.58	2.06	0.0	-	-	-	-	-	-	-	-
245	Placement of cofferdam, linear foot	-	-	-	-	-	-	-	-	-	-	-

TABLE C-1 (continued)

UNIT COST FACTOR LISTING
Minnesota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

Unit Cost Factors					Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
248	Lead paint removal from concrete surfaces, square foot	10.07	8.11	0.1	-	-	-	-	-	-	-	-
253	Overhead cranes/monorails < 10 ton capacity, each	810.83	810.83	11.8	-	3,700	-	-	-	-	-	-
255	Overhead cranes/monorails >10 - 50 ton capacity, each	1,945.99	1,945.99	28.3	-	-	298,832	-	-	-	3,018.5	-
258	Gantry cranes > 50 ton capacity, each	31,034.60	31,034.60	457.3	-	-	712,800	-	-	-	7,200.0	-
260	Structural steel, pounds	0.24	0.20	-	-	1	-	-	-	-	-	-
262	Steel floor grating, square foot	5.73	5.32	0.1	-	-	6	-	1.1	-	-	-
268	Placement of scaffolding in clean areas, square foot	18.58	6.42	0.1	-	-	-	-	-	-	-	-
270	Landscaping with topsoil, acre	24,287.33	3,567.37	52.6	-	-	-	-	-	-	-	-
271	Landscaping w/o topsoil, acre	1,151.70	380.40	5.3	-	-	-	-	-	-	-	-
272	Chain link fencing, linear foot	4.13	3.47	0.1	-	-	-	-	10.0	-	-	-
273	Railroad track, linear foot	28.23	14.43	0.2	-	91	-	-	-	-	-	-
274	Asphalt pavement, square foot	1.02	0.75	0.0	-	-	-	-	-	-	-	-
291	Carbon steel plate 1/4 inch thick, square foot	4.48	3.80	0.1	-	-	10	-	-	-	-	-
294	Carbon steel plate 1/2 inch thick, square foot	4.73	4.00	0.1	-	-	20	-	-	-	-	-
359	Steam drum removal (fossil)	26,089.30	25,934.00	411.6	-	-	480,000	-	-	-	-	-
360	Water drum removal (fossil)	9,683.73	9,654.62	153.2	-	-	320,000	-	-	-	-	-
361	Upper/lower waterwall headers (fossil)	7,308.10	7,278.99	115.5	-	-	120,000	-	-	-	-	-
362	Top sup boiler waterwall (8'x8' section), inches cut	0.87	0.83	0.0	-	-	11	-	-	-	-	-
369	Boiler convective superheaater platens	2,090.33	1,888.47	29.6	-	-	19,501	-	-	-	-	-
370	Boiler radiant superheater platens	884.30	798.91	12.5	-	-	51,652	-	-	-	-	-
371	Boiler reheat platens	884.30	798.91	12.5	-	-	19,501	-	-	-	-	-
372	Boiler economizer platens	1,125.50	1,016.81	15.9	-	-	11,703	-	-	-	-	-
374	Stationary soot blowers	46.10	46.10	0.7	-	-	500	-	-	-	-	50.0
375	Retractable soot blowers	435.82	435.82	6.8	-	-	11,150	-	-	-	-	100.0
376	Process ductwork (8'x8' section), inches cut	0.43	0.40	0.0	-	-	0	-	-	-	-	-
378	Non-asbestos insulated regenerative air preheaters	13,695.05	11,878.10	188.5	-	-	1,376,000	-	-	-	-	-
380	Non-asbestos insulated recuperative air preheaters	7,571.40	6,435.81	101.6	-	-	1,376,000	-	-	-	-	-
382	Induced, forced, primary draft fans	2,080.55	2,033.96	31.9	-	-	30,000	-	-	-	-	3,531.6
383	Coal car dumpers	18,719.68	15,924.38	249.4	-	-	125,000	-	-	-	-	500.0
384	Conveyors	17.64	16.48	0.3	-	-	820	-	-	-	-	-
385	Transfer Towers	0.31	0.17	-	-	-	5	-	-	-	-	-
386	Stacker-reclaimers	190,631.94	190,631.94	3,008.3	-	-	300,000	-	-	-	-	2,000.0
387	Coal crushers	1,260.40	1,248.75	19.3	-	-	36,000	-	-	-	-	250.0
389	Ball mills	1,816.03	1,816.03	28.1	-	-	360,000	-	-	-	-	7,063.1
390	Coal feeders	457.07	445.42	7.1	-	-	1,194	-	-	-	-	-

TABLE C-2

UNIT COST FACTOR LISTING
North Dakota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors					Scrap Weight				
UCF #	Description	Total Cost	Labor Cost	Labor Hours		Carbon Steel No. 1	Mixed Scrap	No. 2 Copper	Large Motor	Aluminum
56	Electrical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6		-	2,212	116.4	-	-
57	Electrical equipment, >10,000 pound	2,779.22	2,779.22	41.0		-	19,950	-	75,610	-
67	Electrical conduit, linear foot	7.06	6.85	0.1		-	-	0.3	-	1.2
72	Mechanical equipment, >10,000 pound	2,779.22	2,779.22	41.0		-	11,938	-	-	-
201	Standard reinforced concrete, cubic yard	82.15	26.84	0.4		183	-	-	-	-
229	Backfill of below grade voids, cubic yard	33.80	4.21	0.1		-	-	-	-	-
230	Excavation of clean material, cubic yard	3.41	1.49	0.02		-	-	-	-	-
235	Building by volume, cubic foot	0.35	0.21	0.003		-	1	-	-	-

TABLE C-3

UNIT COST FACTOR LISTING
South Dakota Station
(Costs are in 2019 dollars/Scrap Weights in pounds)

Unit Cost Factors					Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
2	Piping 0.25 to 2 inches diameter, linear foot	6.97	6.89	0.1	-	4	-	0.5	-	-	-	-
3	Piping >2 to 4 inches diameter, linear foot	9.79	9.68	0.2	-	7	-	0.9	-	-	0.4	-
4	Piping >4 to 8 inches diameter, linear foot	18.71	18.56	0.3	-	22	-	-	-	-	-	-
5	Piping >8 to 14 inches diameter, linear foot	36.52	36.34	0.6	-	57	-	-	-	-	-	-
6	Piping >14 to 20 inches diameter, linear foot	47.48	46.93	0.7	-	-	120	-	-	-	-	-
7	Piping >20 to 36 inches diameter, linear foot	69.86	69.13	1.1	-	-	221	-	-	-	-	-
8	Piping >36 inches diameter, linear foot	83.00	82.27	1.3	-	-	417	-	-	-	-	-
9	Valves <2 inches	133.82	133.10	2.0	-	-	-	-	-	-	-	-
10	Valves >2 to 4 inches	123.95	122.86	1.9	75	-	-	8.8	-	-	4.4	-
11	Valves >4 to 8 inches	187.08	185.61	2.8	510	-	-	-	-	-	-	-
12	Valves >8 to 14 inches	365.17	363.36	5.6	1,066	-	-	-	-	-	-	-
13	Valves >14 to 20 inches	474.79	469.33	7.3	-	-	2,040	-	-	-	-	-
14	Valves >20 to 36 inches	698.56	691.28	10.7	-	-	3,334	-	-	-	-	-
15	Valves >36 inches	829.97	822.69	12.7	-	-	11,535	-	-	-	-	-
24	Pipe hangers for small bore piping, each	43.07	37.61	0.6	-	10	-	-	-	-	-	-
25	Pipe hangers for large bore piping, each	156.07	145.14	2.3	-	50	-	-	-	-	-	-
26	Pump and motor set < 300 pounds	315.72	306.61	4.7	-	-	50	12.5	-	-	-	62.3
27	Pumps, 300-1000 pound pump	865.89	851.31	12.7	293	-	49	48.9	-	-	-	-
28	Pumps, >1000-10,000 pound pump	3,436.62	3,414.76	51.3	2,834	-	472	472.3	-	-	-	-
29	Pumps, >10,000 pound pump	6,647.09	6,581.52	98.9	43,693	-	7,282	7,282.1	-	-	-	-
32	Pump motors, 300-1000 pound pump	362.10	362.10	5.4	-	-	-	-	-	-	-	307.8
33	Pump motors, >1000-10,000 pound pump	1,428.02	1,428.02	21.5	-	-	-	-	-	-	-	3,531.6
34	Pump motors, >10,000 pound pump	3,213.05	3,213.05	48.3	-	-	-	-	-	-	-	42,324.5
38	Main turbine-generator (pounds per MW(e) input)	208,342.91	206,943.98	3,042.0	-	-	851,500	-	-	-	-	851,500.0
39	Heat exchanger <3000 pound	1,842.38	1,820.52	27.3	-	-	416	623.4	-	-	-	-
40	Heat exchanger >3000 pound	4,638.92	4,551.49	68.3	-	-	5,599	8,397.9	-	-	-	-
41	Feedwater heater/deaerator	13,098.22	12,923.36	194.2	-	-	12,000	18,000.0	-	-	-	-
49	Main condenser (pounds per MW(e) input)	572,617.94	553,556.38	8,243.6	149,400	-	149,400	199,200.0	-	-	-	-
51	Tanks, <300 gallons, filters, and ion exchangers	406.10	395.17	6.0	-	-	401	401.2	-	-	-	-
52	Tanks, 300-3000 gallons	1,280.24	1,258.38	19.1	-	-	2,700	300.0	-	-	-	-
53	Tanks, >3000 gallons, square foot surface	10.63	10.35	0.2	-	21	-	-	-	-	-	-
54	Electrical equipment, <300 pound	171.33	171.33	2.6	-	-	56	-	-	-	2.9	-
55	Electrical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	624	-	-	-	32.8	-
56	Electrical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	2,212	-	-	-	116.4	-
57	Electrical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	19,950	-	-	-	1,050.0	-
59	Electrical transformers < 30 tons	1,930.13	1,930.13	28.4	-	-	11,250	-	-	-	3,750.0	-
60	Electrical transformers > 30 tons	5,558.44	5,558.44	81.9	-	-	375,000	-	-	-	125,000.0	-

TABLE C-3 (continued)

UNIT COST FACTOR LISTING
South Dakota Station
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors				Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
61	Standby diesel-generator, <100 kW	1,971.46	1,971.46	29.1	2,340	-	-	-	-	-	-	260.0
64	Fluorescent light fixture	71.90	71.90	1.1	-	-	-	-	-	-	-	-
65	Incandescent light fixture	36.05	36.05	0.6	-	-	-	-	-	-	-	-
66	Electrical cable tray, linear foot	16.09	15.73	0.2	-	-	-	-	6.6	6.6	-	-
67	Electrical conduit, linear foot	7.03	6.85	0.1	-	-	-	-	3.4	3.4	-	-
69	Mechanical equipment, <300 pound	171.33	171.33	2.6	-	-	127	-	-	-	-	-
70	Mechanical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	641	-	-	-	-	-
71	Mechanical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	4,184	-	-	-	-	-
72	Mechanical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	11,938	-	-	-	-	-
76	HVAC equipment, <300 pound	207.18	207.18	3.1	-	-	184	-	-	-	-	-
77	HVAC equipment, 300-1000 pound	708.37	708.37	10.6	-	-	643	-	-	-	-	-
78	HVAC equipment, 1000-10,000 pound	1,411.80	1,411.80	21.0	-	-	3,813	-	-	-	-	-
82	HVAC ductwork, pound	0.68	0.68	0.0	-	-	-	-	1.0	-	-	-
201	Standard reinforced concrete, cubic yard	74.02	26.84	0.4	-	183	-	-	-	-	-	-
202	Grade slab concrete, cubic yard	84.20	30.65	0.5	-	183	-	-	-	-	-	-
206	Heavily rein concrete w/#9 rebar, cubic yard	106.96	39.28	0.6	-	730	-	-	-	-	-	-
222	Hollow masonry block wall, cubic yard	25.45	10.27	0.1	-	66	-	-	-	-	-	-
229	Backfill of below grade voids, cubic yard	29.45	4.21	0.1	-	-	-	-	-	-	-	-
235	Building by volume, cubic foot	0.33	0.21	-	-	-	1	-	-	-	-	-
236	Building metal siding, square foot	1.71	1.28	0.0	-	-	-	-	2.4	-	-	-
242	Standard asphalt roofing, square foot	3.01	3.01	0.1	-	-	-	-	-	-	-	-
248	Lead paint removal from concrete surfaces, square foot	9.80	7.96	0.1	-	-	-	-	-	-	-	-
253	Overhead cranes/monorails < 10 ton capacity, each	810.83	810.83	11.8	-	3,700	-	-	-	-	-	-
255	Overhead cranes/monorails >10 - 50 ton capacity, each	1,945.99	1,945.99	28.3	-	-	298,832	-	-	-	3,018.5	-
260	Structural steel, pounds	0.23	0.20	-	-	1	-	-	-	-	-	-
262	Steel floor grating, square foot	5.70	5.32	0.1	-	-	6	-	1.1	-	-	-
270	Landscaping with topsoil, acre	23,009.82	3,567.37	52.6	-	-	-	-	-	-	-	-
271	Landscaping w/o topsoil, acre	1,104.15	380.40	5.3	-	-	-	-	-	-	-	-
272	Chain link fencing, linear foot	4.09	3.47	0.1	-	-	-	-	10.0	-	-	-
274	Asphalt pavement, square foot	1.01	0.75	0.0	-	-	-	-	-	-	-	-
293	Carbon steel plate 3/8 inch thick, square foot	4.56	3.90	0.1	-	-	15	-	-	-	-	-
294	Carbon steel plate 1/2 inch thick, square foot	4.68	4.00	0.1	-	-	20	-	-	-	-	-
359	Steam drum removal (fossil)	26,079.72	25,934.00	411.6	-	-	480,000	-	-	-	-	-
376	Process ductwork (8'x8' section), inches cut	0.43	0.40	0.01	-	-	0.03	-	-	-	-	-

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	)))))))	**ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION; ORDER APPROVING REFUND PLAN** **EL22-017**

On June 30, 2022, the South Dakota Public Utilities Commission (Commission) received an Application from Northern States Power Company dba Xcel Energy (Xcel) for approval to increase rates for electric service to customers in its South Dakota service territory by approximately $44.1 million annually or approximately 17.9% based on Xcel's 2021 historic test year. Xcel states a typical residential electric customer using 750 kWh per month would see an increase of $19.58 per month. The proposed changes affect approximately 97,500 customers.

On July 7, 2022, the Commission electronically transmitted notice of the filing and the intervention deadline of September 16, 2022, to interested individuals and entities on the Commission's PUC Weekly Filings electronic listserv. On September 16, 2022, Steve Wegman, an Xcel customer, filed to intervene in the docket. Comments were received from a number of persons, all of which are available for review on the Commission's web site for this docket at https://puc.sd.gov/Dockets/Electric/2022/EL22-017Comments.aspx.

On July 22, 2022, the Commission issued an Order Suspending Operation of Proposed Rates; Order Assessing Filing Fee; Order Authorizing Consulting Contracts. On September 29, 2022, the Commission issued an Order Granting Intervention to Steve Wegman. On November 15, 2022, Xcel filed its Notice of Intent to Implement Interim Rates effective for service on or after January 1, 2023. Multiple customers of Xcel filed comments requesting the rate be suspended and a public hearing be held. On November 28, 2022, the Commission held a public meeting on the Application in Sioux Falls, South Dakota. On May 24, 2023, Xcel and Commission staff filed a Joint Motion for Approval of Settlement Stipulation, and a Settlement Stipulation, including Xcel's Interim Refund Plan, and Commission staff filed a Staff Memorandum Supporting Settlement Stipulation. On June 2, 2023, Intervenor Steve Wegman filed his Concurrence to the Settlement Stipulation.

The revised tariff sheets proposed by Xcel, effective for service rendered on and after July 1, 2023, are as follows:

South Dakota Electric Rate Book – SDPUC No. 2

Section No. 1
9th Revised Sheet No. 2 — Cancelling 8th Revised Sheet No. 2

Section No. 3
2nd Revised Sheet No. 1 — Cancelling 1st Revised Sheet No. 1

Section No. 4

1st Revised Sheet No. 3	Cancelling Original Sheet No. 3
1st Revised Sheet No. 4	Cancelling Original Sheet No. 4
2nd Revised Sheet No. 5	Cancelling 1st Revised Sheet No. 5

Section No. 5

7th Revised Sheet No. 1	Cancelling 6th Revised Sheet No. 1
5th Revised Sheet No. 1.1	Cancelling 4th Revised Sheet No. 1.1
9th Revised Sheet No. 2	Cancelling 8th Revised Sheet No. 2
7th Revised Sheet No. 7	Cancelling 6th Revised Sheet No. 7
7th Revised Sheet No. 9	Cancelling 6th Revised Sheet No. 9
9th Revised Sheet No. 11	Cancelling 8th Revised Sheet No. 11
7th Revised Sheet No. 14	Cancelling 6th Revised Sheet No. 14
7th Revised Sheet No. 21	Cancelling 6th Revised Sheet No. 21
10th Revised Sheet No. 23	Cancelling 9th Revised Sheet No. 23
7th Revised Sheet No. 25	Cancelling 6th Revised Sheet No. 25
7th Revised Sheet No. 28	Cancelling 6th Revised Sheet No. 28
7th Revised Sheet No. 31	Cancelling 6th Revised Sheet No. 31
7th Revised Sheet No. 34	Cancelling 6th Revised Sheet No. 34
2nd Revised Sheet No. 38	Cancelling 1st Revised Sheet No. 38
2nd Revised Sheet No. 39	Cancelling 1st Revised Sheet No. 39
7th Revised Sheet No. 40	Cancelling 6th Revised Sheet No. 40
8th Revised Sheet No. 56	Cancelling 7th Revised Sheet No. 56
5th Revised Sheet No. 57	Cancelling 4th Revised Sheet No. 57
9th Revised Sheet No. 58	Cancelling 8th Revised Sheet No. 58
6th Revised Sheet No. 59	Cancelling 5th Revised Sheet No. 59
7th Revised Sheet No. 63	Cancelling 6th Revised Sheet No. 63
9th Revised Sheet No. 64	Cancelling 8th Revised Sheet No. 64
3rd Revised Sheet No. 66	Cancelling 2nd Revised Sheet No. 66
7th Revised Sheet No. 68	Cancelling 6th Revised Sheet No. 68
12th Revised Sheet No. 74	Cancelling 11th Revised Sheet No. 74
2nd Revised Sheet No. 75	Cancelling 1st Revised Sheet No. 75
3rd Revised Sheet No. 76	Cancelling 2nd Revised Sheet No. 76

Section No. 6

2nd Revised Sheet No. 4	Cancelling 1st Revised Sheet No. 4
3rd Revised Sheet No. 24	Cancelling 2nd Revised Sheet No. 24
2nd Revised Sheet No. 27	Cancelling 1st Revised Sheet No. 27
Original Sheet No. 27.1	
Original Sheet No. 27.2	
2nd Revised Sheet No. 29	Cancelling 1st Revised Sheet No. 29
Original Sheet No. 29.1	
1st Revised Sheet No. 30	Cancelling Original Sheet No. 30

Section No. 8

5th Revised Sheet No. 2.1	Cancelling 4th Revised Sheet No. 2.1
3rd Revised Sheet No. 2.2	Cancelling 2nd Revised Sheet No. 2.2
3rd Revised Sheet No. 3.1	Cancelling 2nd Revised Sheet No. 3.1
3rd Revised Sheet No. 4.1	Cancelling 2nd Revised Sheet No. 4.1
1st Revised Sheet No. 24	Cancelling Original Sheet No. 24

The Commission has jurisdiction over this matter pursuant to SDCL Chapters 1-26 and 49-34A, including 1-26-20, 49-34A-3, 49-34A-6, 49-34A-8, 49-34A-8.4, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-17, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-21, and 49-34A-22.

At its regularly scheduled meeting of June 6, 2023, the Commission considered this matter. The Commission heard from Xcel and Commission staff concerning the Joint Motion and Settlement Stipulation. Having thoroughly reviewed the filings in the docket and after having made further extensive inquiry of the parties, the Commission found that the terms and conditions proposed in the Settlement Stipulation were just, reasonable, and in the public interest and that good and sufficient cause was demonstrated to approve the Settlement Stipulation. The Commission voted unanimously to grant the Joint Motion for Approval of Settlement Stipulation that granted Xcel an annual increase in base rates to recover a net revenue deficiency of approximately $3.6 million. When the base rate increase is combined with the 2023 Infrastructure Rider projects, the estimated 2023 overall revenue increase is approximately $14.3 million, or an approximate 5.85% increase in retail revenues. The Commission also considered the issue of approval of Xcel's Interim Refund Plan. Finding that the Interim Refund Plan as proposed by Xcel properly balances the interests of Xcel in having a workable plan that is not unduly administratively burdensome and the interests of customers in obtaining a prompt and substantially complete refund of non-*de minimis* over-collections during the interim period and is therefore just and reasonable, the Commission voted unanimously to approve Xcel's Interim Refund Plan. It is therefore

ORDERED, that the Joint Motion for Approval of Settlement Stipulation is hereby granted. The Settlement Stipulation is incorporated by reference into this Order the same as if it had been set forth in its entirety herein. It is further

ORDERED, that Xcel's Interim Refund Plan is approved as filed. It is further

ORDERED, that the aforementioned tariff sheets are approved for service rendered on and after July 1, 2023.

Dated at Pierre, South Dakota, this 8th day of June 2023.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically or by mail.

By: Adam de Hueck

Date: 6/8/23

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Kristie Fiegen
KRISTIE FIEGEN, Chairperson

Gary Hanson
GARY HANSON, Commissioner

Chris Nelson
CHRIS NELSON, Commissioner

Direct Testimony and Schedules
Laurie J. Wold

Before the South Dakota Public Service Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in South Dakota

Case No. EL22-___
Exhibit___(LJW-1)

Capital Investments, Depreciation, and Nuclear Decommissioning

June 30, 2022

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laurie J. Wold. My business address is 401 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. (XES) as a Senior Manager of Capital Asset Accounting. XES is a wholly owned subsidiary of Xcel Energy Inc. and provides an array of support services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company (Xcel Energy, NSPM, or the Company), operating in South Dakota. My Statement of Qualifications is attached as Exhibit___(LJW-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. First, I provide information regarding the Company's material capital additions since its last rate case, which was filed in 2014. I then support the underlying information for the calculation of the level of proposed depreciation expense effective January 1, 2023, which includes recommended changes to average service lives, remaining lives, net salvage rates, and depreciation rates, where applicable, for all Company assets used in providing electric service. This includes changes related to the closures of Sherco Units 1 & 2 and adjustments to the remaining lives of Sherco Unit 3 and Allen S. King. I also support the Company's recommendation regarding nuclear decommissioning accruals. Unless otherwise noted, my testimony provides total Company information. Company witness Mr. Benjamin C. Halama includes the South Dakota electric jurisdictional amounts in his pro forma year revenue requirement, which is a 2021 historical test year with 24 months of known and measureable changes.

Q. SPECIFICALLY, WHAT DO YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony addresses three topics: historical capital additions, depreciation expense, and nuclear decommissioning expense. In the capital additions section, I discuss material historical additions which have occurred since the Company's last rate case. In the depreciation section, I present the depreciation changes proposed for the production, transmission, distribution, electric general and intangible, and common general and intangible assets. I discuss the depreciation statistics for all assets in the electric and common utilities. In the nuclear decommissioning section, I present updates to the underlying cost estimate, the fund earnings rates, and the escalation rate. In considering all these areas, it should be kept in mind that the Company's last rate case was filed in 2014 using a 2013 test year.

Q. WHAT IS THE IMPACT OF THE DEPRECIATION CHANGES YOU RECOMMEND?

A. The change in lives and net salvage rates that I propose in my testimony results in a decrease of $9.2 million in Electric Production depreciation expense at a total NSPM Company level and a decrease of $0.5 million for the South Dakota retail jurisdiction. The primary contributing factors to this decrease include, but are not limited to, the impending expiration of Sherco Units 1 & 2 depreciation expense and extending lives at the Nobles and Grand Meadow wind farms, offset by shortening the remaining life at Allen S. King and Sherco Unit 3. The electric transmission, distribution, and general (TD&G) assets accounted for a NSPM Company level increase of $5.2 million and a South Dakota jurisdictional increase of $1.4 million. The overall South Dakota jurisdictional increase, related to the TD&G assets, is primarily driven by the distribution capital additions that are directly assigned to the South Dakota jurisdiction. The NSPM Company common utility assets decreased expense by $11.2 million and the associated South Dakota jurisdictional amount decreased $0.7 million.

These recommended depreciation changes were then applied to the plant and accumulated depreciation balance (i.e., the depreciation reserve) as of January 1, 2023, which included a depreciation passage of time.

The nuclear decommissioning accrual increased by approximately $7.0 million (South Dakota Jurisdictionalized). With respect to the Nuclear Decommissioning Trust accrual, I am recommending the accrual level to be set at $8.2 million due to the need to capture decreases in the expected long term return on trust assets and revisions to amounts to be collected in light of changes in the South Dakota jurisdictional allocation and current underfunding.

Table 1 below summarizes the Company's proposed test year depreciation expense changes.

Table 1

Test Year Depreciation Expense Changes

(in millions)	**Total Company**	**South Dakota Jurisdictionalized**
Electric Production	$ (9.2)	$ (.05)
Electric TD&G	5.2	1.4
Common Utility Assets	(11.2)	(0.7)
Nuclear Decommissioning*	N/A	7.0
Total	$ (15.2)	$ 7.2

*Nuclear decommissioning accruals are calculated at the jurisdictional level and not at the NSPM Total Company level.

II. CAPITAL ADDITIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the Company's historical capital additions for the period 2014 through 2021 (since the Company's last rate case).

A. Capital Additions 2014-2021

Q. WHAT WERE THE COMPANY'S CAPITAL ADDITIONS IN THE PERIOD OF 2014-2021?

A. The Company placed into service capital additions totaling $9.3 billion in the historical period of 2014-2021. Exhibit___(LJW-1), Schedule 2, is a Plant-in-Service Roll forward for the period 2014-2021. Unless otherwise noted, my testimony provides total Company information. Mr. Halama includes the South Dakota electric jurisdictional amounts in his pro forma year revenue requirement.

Q. WHAT WERE THE PRIMARY DRIVERS OF CAPITAL ADDITIONS IN THE 2014-2021 PERIOD?

A. From 2014-2021, the Company made a wide variety of investments across its system to provide reliable, safe, and cost-effective service to its customers. In particular, investments in initiatives and individual projects in the following areas were the primary drivers of the Company's capital additions: wind farms, regional expansion transmission projects, its nuclear generating fleet, a new natural gas combustion turbine, and updating its information technology and business systems. Below, I provide more information about the Company's investments in each of those areas.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN WIND FARMS IN THE 2014-2021 PERIOD.

A. To harness the excellent wind resource of South Dakota and neighboring states and turn it into emissions-free power for its customers—at a time when market pricing of new wind generation was historically low—the Company invested $2.9 billion to build and maintain approximately 2,070 megawatts (MW) of wind farms across the Minnesota, South Dakota, North Dakota and Wisconsin NSP system between 2014-2021. Please see Table 2 presenting the in-service year, actual capital additions, and nameplate capacity for the wind farms in-serviced during the 2014-2021 historical period.

Table 2
Wind Farms

Wind Farm	In-Service	2014-2021 Additions	Nameplate Capacity
Blazing Star 2	2021	$338 M	200 MW
Pleasant Valley	2015	$332 M	200 MW
Freeborn	2021	$321 M	200 MW
Crowned Ridge	2020	$309 M	200 MW
Blazing Star 1	2020	$307 M	200 MW
Courtenay	2016	$284 M	200 MW
Border	2015	$265 M	150 MW
Foxtail	2019	$236 M	150 MW
Lake Benton	2019	$161 M	100 MW
Mower	2021	$158 M	99 MW
Jeffers	2020	$70 M	44 MW
Community Wind	2020	$66 M	26 MW
Nobles	2010	$7 M	200 MW
Grand Meadow[1]	2008	$5 M	100 MW

[1] Note that major classifications for Nobles and Grand Meadows wind farms occured prior to 2014, in 2010 and 2008 respectively, and the additions presented in Table 2 support continuing operations.

These wind projects—and the additional projects the Company has added in subsequent years—will continue to provide substantial benefits to customers. Xcel Energy has been a national leader in wind power since 2005, and wind will continue to play a vital role as the Company works to reduce carbon emissions 80% by 2030 and make progress on its vision to deliver 100% carbon-free electricity by 2050.

Q. ARE THERE ANY WIND FARMS NOT PRESENTED IN TABLE 2 THAT SHOULD BE DISCUSSED?

A. Yes, there are three wind farms, Dakota Range, Northern, and Rock Aetna wind farms, which are not included in the 2014-2021 historical period but will be addressed in the depreciation section of my testimony.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN REGIONAL EXPANSION TRANSMISSION PROJECTS IN THE 2014-2021 PERIOD.

A. To meet the growing need for transmission in the region, the Company made capital additions totaling $2.0 billion in regional expansion transmission projects, including projects in South Dakota, North Dakota, and Minnesota as part of the CapX2020 initiative.

These CapX2020 projects were major upgrades to the regional transmission system to support local reliability, regional reliability, and renewable generation. Prior to the CapX2020 projects, there had not been a major upgrade to the Upper Midwest's electric transmission grid in nearly 40 years. Under the CapX2020 initiative, the eleven transmission-owning utilities in Minnesota, North Dakota, South Dakota, and Wisconsin collaborated to study and plan for the future of the regional transmission system. The result was multiple transmission planning studies that supported the development of the Regional Expansion projects.

The Company, through its affiliate Northern States Power Company, a Wisconsin corporation (NSPW), also placed into service a 182-mile 345 kV transmission line from La Crosse, Wisconsin to Madison, Wisconsin in concert with American Transmission Company. This resulted in a total capital addition of $191 million which is recovered through the Interchange Agreement between the Company and NSPW.

Q. PLEASE DESCRIBE THE COMPANY'S NUCLEAR GENERATING FLEET.

A. Xcel Energy owns and operates three nuclear units: one unit in Monticello, Minnesota and two units at Prairie Island in Welch, Minnesota.

Monticello is a single-unit boiling water reactor rated for gross output at 671 MW that was originally licensed by the Nuclear Regulatory Commission (NRC) in 1970. The NRC approved a renewed license for the facility in 2006, allowing the plant to operate through 2030. The Company intends to seek a license extension to allow the plant to operate an additional 10 years, to 2040.

Prairie Island is a two-unit pressurized water reactor, with each unit rated at 550 MW gross output capacity. The NRC licensed Prairie Island's two units in 1973 and 1974, respectively. The initial operating licenses were set to expire in 2013 and 2014. In 2011, the NRC approved renewed licenses for Prairie Island Units 1 and 2, extending their operating lives until 2033 and 2034, respectively.

Nuclear is a critical source of power generation for the Company's customers. Monticello and Prairie Island continue to be two of Xcel Energy's most reliable system-wide baseload electric generation assets, providing almost 30 percent of the electricity to the Company's system in the Upper Midwest. Monticello has operated at an average capacity factor of 94.2 percent, including 99.3 percent in 2018 and 98.6 percent in 2020, both non-refueling years. In that same timeframe, Prairie Island achieved a combined average capacity factor of more than 95 percent, including a 99.9 percent on Unit 2 in 2018; 99.4 percent on Unit 1 in 2019; and 99.3 percent on Unit 2 in 2020, all non-refueling years.

These plants are part of a diverse operating portfolio that provides a hedge against changes in resource availability, fossil fuel prices, and future emissions regulations. They are important sources of low-cost, base-load power that do not have carbon emissions, and their continued safe, reliable, and efficient operation are critical to the Company's commitment to provide reliable and reasonably priced electricity to South Dakota consumers.

Q. WHAT WAS THE COMPANY'S OVERALL INVESTMENT IN ITS NUCLEAR GENERATING FLEET IN THE 2014-2021 PERIOD?

A. To generate reliable, base load, carbon-free power, the Company invested $1.1 billion in its nuclear generating fleet in the period of 2014-2021.

Q. PLEASE SUMMARIZE THE COMPANY'S KEY INVESTMENTS IN ITS NUCLEAR FLEET IN THE 2014-2021 PERIOD.

A. In the 2014-2021 period, the Company invested in mandated compliance projects, such as safety measures required by federal regulators in the wake of the Fukushima nuclear incident in Japan; safety, cybersecurity, and fire-protection improvements; reliability investments including life cycle management, such as an extended power uprate at Monticello and replacement of both main electric generators at Prairie Island; and dry-cask storage for spent nuclear fuel. I provide additional information about those investments below.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN NUCLEAR MANDATED COMPLIANCE IN THE 2014-2021 TIME PERIOD.

A. Mandated Compliance includes regulatory, security, and license commitment activities required by Federal or state regulators (normally the NRC), including industry commitments made to the NRC, as well as projects that require NRC approval. The Company made capital additions across Monticello and Prairie Island to implement safety measures required by federal regulators in the wake of the Fukushima nuclear incident in Japan. Such measures included installation of enhanced spent fuel pool instrumentation and modifications to electrical and mechanical systems to augment plant cooling capability.

The Company also made capital additions for its fire-protection program at Prairie Island and at Monticello, all to reduce the likelihood of a fire incident in the first place and reduce the impacts of any fire that may occur. To ensure protection of generating assets and of the public, the Company also made capital additions for its cyber-security program across Monticello and Prairie Island and added physical security at Monticello.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN NUCLEAR RELIABILITY IN THE 2014-2021 TIME PERIOD.

A. The Company's investments in reliability projects improve equipment reliability, reduce maintenance activities, and ensure that plants run efficiently and reliably for their full planned lifecycle.

In the 2014-2021 period, the Company completed the Life Cycle Management/Extended Power Uprate work at the Monticello nuclear generating plant that was underway at the time of the company's last South Dakota rate case. The Company also invested in reliability projects at Prairie Island, such as replacement of a reactor coolant pump, process control systems, and a cooling tower. The Company also made a major investment in the replacement of the main electrical generator for both Prairie Island units.

Q. PLEASE DISCUSS THE COMPANY'S CAPITAL ADDITIONS FOR DRY-CASK STORAGE.

A. The Company made capital additions for dry cask storage, which are driven by the Federal government's delay in providing a permanent, long-term spent fuel storage facility, and the requirement that the Company store spent fuel on site in the interim. These investments included storage casks, expansion of the independent spent fuel storage installation at Prairie Island, and the loading of spent fuel into casks at Monticello.

Q. WHAT HAS BEEN THE RESULT OF THE CAPITAL IMPROVEMENTS OF THE NUCLEAR FACILITIES?

A. The projects the Company has undertaken at Prairie Island and Monticello since 2014 have yielded significant benefits for customers and the system. In years where there is only one unit scheduled for a refueling outage, the fleet overall now operates at 95% capacity or above. In 2019, which had two units with refueling outages, the fleet performed at 92.6%. One key reason for this high capacity factor was the record run of over 700 consecutive days at both its Monticello and Prairie Island plants, the longest run of any Xcel Energy nuclear units in its history. The Company's nuclear fleet is more reliable than it has ever been, and O&M costs for the two facilities are down. In addition, as a result of the improvements made in response to the Fukushima incident and the other security, fire protection, reliability and safety capital improvements made since 2014, the facilities, which have operated safely since the 1970s, are now even safer, more secure, and more resilient.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW NATURAL GAS COMBUSTION TURBINE.

A. In 2018, the Company placed into service a new natural gas combustion turbine (Unit 6) at our existing Black Dog generating plant in Minnesota. The Company built the new unit to meet a need in the system, and the choice of natural gas reflects the Company's commitment to a robust mix of generation types.

Q. PLEASE DISCUSS THE COMPANY'S KEY INVESTMENTS IN BUSINESS SYSTEMS IN THE 2014-2021 PERIOD.

A. To streamline operations and enable employees to perform responsibilities more efficiently, the Company invested in new business systems, specifically a new SAP General Ledger (GL) system, a new Work and Asset Management (WAM) system, and our new Advanced Distribution Management System (ADMS). The Company put the new GL in service in 2015, and the first WAM deployment went in service in 2016.

Q. PLEASE DISCUSS THE COMPANY'S GL AND ITS GL-RELATED INVESTMENTS.

A. The GL is the Company's financial record-keeping system. The Company's historical system was reaching the end of its life and its vendor was going to cease providing support. Based on its evaluation of options, the Company decided that replacement of the historical GL with a new GL offered by SAP was the best course of action. The new GL provides better analysis of how business drivers impact accounting results and a better ability to trace connections between Generally Accepted Accounting Principles (GAAP) accounting and individual Federal Energy Regulatory Commission (FERC) accounts, among other benefits. These improvements make the Company's operations more efficient.

Q. PLEASE DISCUSS THE COMPANY'S WAM AND ITS WAM-RELATED INVESTMENTS.

A. A WAM system is the core technology for planning and scheduling utility work, managing outages, procuring materials, and managing assets and inventory. Historically, Xcel Energy had three core WAM systems, but the original software vendors were no longer providing full support or upgrades with robust protection against system failure or cyber-attacks. This situation created potential vulnerabilities and made repairs more costly to customers with risk of delays that could jeopardize certain aspects of the Company's day-to-day operations. Accordingly, the Company replaced these three old systems with an integrated solution that is based on current technology and works in tandem with the Company's new GL system.

Q. PLEASE DISCUSS THE COMPANY'S ADMS AND ADMS-RELATED INVESTMENTS.

A. ADMS provides an integrated operating and decision software and hardware support system that allows control room operators, field personnel, and engineers to monitor, control, and optimize the electric distribution system. ADMS gives access to real-time or near real-time data to provide all information on operator console(s) at the control center in an integrated manner and will allow different operating systems and technologies to communicate with each other. ADMS investments began in 2019 with the purchase of servers and the system went into operation in 2021.

Q. PLEASE DESCRIBE THE COMPANY'S METER REPLACEMENT PROJECT INVESTMENTS.

A. The Company began capital additions for the Meter Replacement project in 2019. In his Direct Testimony, Company witness Mr. Marty Mensen provides more detail regarding these investments and the benefits they provide customers.

III. DEPRECIATION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The Company is requesting a revision to its remaining lives, net salvage rates, retirement curves, and depreciation rates for its production, transmission, distribution, general, and intangible assets. This section details the changes and includes supporting information for the requested changes.

Q. WHAT IS DEPRECIATION?

A. The term "depreciation" is a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. However, the amount allocated to any one accounting period does not necessarily represent an actual loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Q. WHAT IS A NET SALVAGE RATE?

A. Net salvage is the difference between the gross salvage (what the asset or its remaining scrap was sold for) and the removal cost (cost to remove and dispose of the asset). If the removal cost exceeds gross salvage, net salvage is negative. Some plant assets can experience significant negative removal cost percentages due to the amount of removal cost and the timing of any capital additions versus the retirement. Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the associated assets.

Q. WHY IS IT IMPORTANT TO SET THE RIGHT LEVEL OF DEPRECIATION EXPENSE IN A RATE CASE?

A. The goal in setting depreciation lives and rates is to match depreciation recovery with the useful lives of assets to ensure current customers are equitably paying for the cost of the asset over the period they receive benefits from the assets, avoiding intergenerational inequity. The proposed depreciation rates and associated level of depreciation expense presented reflects the depreciation cost of service and proposed rates effective January 1, 2023.

Q. WHAT CHANGES ARE YOU PROPOSING FOR APPROVED LIVES, NET SALVAGE RATES, RETIREMENT CURVES, OR DEPRECIATION RATES IN THIS CASE?

A. I propose several changes affecting depreciation expense for production assets due to changing the remaining life, updating the dismantling cost that is the basis of the negative net salvage rate, and a reserve reallocation. For transmission, distribution, general, and intangible assets, I propose changes to the average remaining life depreciation rates based on underlying changes to the average service life, retirement curves, and net salvage rates. I discuss the full scope of depreciation expense changes proposed in my testimony below; however, the major drivers to the proposed change in depreciation expense are as follows:

- *Steam Production,* the impending expiration of depreciation expense of Sherco Units 1 & 2 and a proposed reserve reallocation at the Sherco site (Units 1, 2 & 3) and the shortening of the remaining life at Sherco Unit 3 and Allen S. King;
- *Other Production*, extending the remaining life of Nobles and Grand Meadow wind farms, due to wind repowering and the proposed reserve reallocations; and
- *Transmission, Distribution, General, and Intangible (TD&G)*, updating new average service lives, retirement curves, net salvage rates, and depreciation rates for all assets in accordance with the most recent depreciation study and requesting initial parameters for several new accounts or subaccounts of assets.

The depreciation expense changes are supported by several exhibits to my testimony. Exhibit___(LJW-1), Schedules 3-5 are related to the Electric Production segment. Schedule 3 is the 2020 Dismantling Study performed by TLG Services (TLG) on the Company's production assets. Schedule 4 is a summary of the proposed remaining lives and net salvage rates for each plant by FERC account. Schedule 5 is a calculation of proposed net salvage rates and a comparison of net salvage rates currently approved compared to the proposed rates.

Exhibit___(LJW-1), Schedules 6-8 support the average service lives, net salvage rates, and retirement curves for the transmission, distribution, electric general, and common general assets, using plant and depreciation reserve balances at December 31, 2021. Schedule 6 is the 2017 Depreciation Study performed by Alliance Consulting Services (Alliance) on the Company's TD&G assets. Schedule 7 is a summary of the currently approved and proposed average service lives, net salvage rates, depreciation rates, and retirement curve for segment by FERC account. Schedule 8 shows how the proposed depreciation rates were calculated.

Unless specifically stated, all depreciation numbers discussed above and later in my testimony are at total NSPM Company level. Mr. Halama provides the South Dakota jurisdictional costs for the pro forma year in his Direct Testimony.

All of these changes are summarized in Table 3, below, which shows the overall change to depreciation expense by functional class based on 1/1/2023 plant and depreciation reserve balances.

Table 3

Summary of Depreciation Expense Change

Functional Class	**Change in Depreciation Expense (Total Company)**	**Change in Depreciation Expense (SD Jurisdiction)**
Electric Utility		
Steam Production	$1,819,645	$102,488
Hydro Production	(41,318)	(2,334)
Other Production	(11,025,863)	(622,830)
Total Electric Production	($9,247,536)	($522,676)
Transmission	$10,446,259	$590,089
Distribution (SD Located Only)	1,251,588	1,251,588
Electric General	(9,270,171)	(606,601)
Electric Intangibles	2,808,832	183,331
Total Electric TD&G	$5,236,507	$1,418,406
Total Electric Utility	**($4,011,028)**	**$896,031**
Common Utility		
Common General	($11,561,002)	($722,276)
Common Intangibles	333,300	20,035
Total Common Utility	**($11,227,702)**	**($702,241)**
Total Depreciation Expense Change	**($15,238,730)**	**$193,789**

A. Production Assets

Q. PLEASE DESCRIBE THE CHANGES TO PRODUCTION ASSETS AND HOW THIS IMPACTS DEPRECIATION EXPENSE.

A. Production assets use a remaining life method to determine depreciation expense, which is the current net plant adjusted for expected net salvage divided by the current remaining life. The remaining lives for the production assets were evaluated based on the Company's expectations for operating each unit at a generating station, with the common assets (those assets shared by all units) at the generating station assuming the remaining life of the longest-lived unit.

The Company met with the employees who are knowledgeable about the planning, construction, and operations at each facility. During these meetings, the Company reviewed each facility to:

- Understand the major overhauls, rebuilds, and routine construction projects performed in the past few years;
- Consider the scope of current and upcoming projects; and,
- Forecast the likelihood of the facility achieving the currently approved remaining life in light of the past, current, and near future projects.

The Company considers these items along with its plans presented in its current resource planning cycle to understand the operational life of each facility and determine an appropriate remaining life that would be consistent with the likely actual life of a particular facility. Exhibit__(LJW-1), Schedules 3-5 provide detail comparing depreciation expense using currently approved lives and net salvage rates set in 2014 versus using the lives and net salvage rates as proposed in this filing.

For the negative net salvage rates, the Company utilized a comprehensive 2020 Dismantling Study prepared by TLG for all steam, hydro, and other production electric generating plants. The Dismantling Study is included as Exhibit__(LJW-1), Schedule 3.

Q. IN GENERAL, WHAT CHANGES WERE MADE TO REMAINING LIVES?

A. To begin its analysis of remaining lives, the Company incorporated an eight year passage of time adjustment to the last Commission approved remaining lives of all facilities. The passage of time adjustment does not change the annual depreciation accrual, but simply reflects that the Company's production facilities as of January 1, 2022 have aged eight years since January 1, 2014, when the depreciation expense was last updated for the Company.

The Company also adjusted remaining lives to align the terminal retirement date with current expectations. Remaining lives for depreciation purposes have not been updated for South Dakota rates since 2014. Given this passage of time, it is necessary for the Company to update remaining lives with current reality.

Changes to lives within the Other Production function include:

- Angus Anson Units 2&3 to operate through 2040 and Unit 4 to operate into 2045. Unit 3 had a major rotor out overhaul in 2018/2019 and Unit 2 will have a similar overhaul in 2023. This capital expense to rebuild the combustion turbine will extend the life into 2040 per manufacturer recommendations and expectations based on the estimated number of peaking plant unit starts and hours. Unit 4 is being maintained in accordance with manufacturer recommendations. Based on the manufacturer's expectations along with revised estimations of the number of peaking plant unit starts and hours, the Company is anticipating operating the unit until May 31, 2045;
- Black Dog Unit 5 FERC Structures and Improvements account life was extended to match that of the newly completed Unit 6. The Company plans to dismantle the structures at Unit 5 and Unit 6 simultaneously at the retirement date of the unit with the longest life in order to minimize the amount spent to decommission the facility. Therefore, Unit 5 will not be dismantled until Unit 6 is also retired. This practice can be seen in the lives of the Structures and Improvements accounts for several of the Company's other plants including Angus Anson and Blue Lake;

- Blue Lake Units 1-4 extended through June 2023. These units were analyzed based on the number of starts and the hours run, and it was determined that with minimal operating costs, the Company would anticipate them lasting through mid-2023;
- Blue Lake Units 7 & 8's combustion turbines are the same model as Angus Anson Unit 4, and they were installed in the same year. Plant personnel maintain these units on a similar level and timeframe and, therefore, these units are expected to have a similar end of life date. Thus, the Company is requesting a retirement date of May 31, 2045;
- The Luverne Wind-to-Battery asset is to be retired as of January 1, 2021. This is a 1 MW wind energy battery-storage system installed in December 2009, and connected to a nearby 11 MW wind farm formerly owned by Minwind Energy, LLC. When the Minwind facility stopped producing energy in October of 2019 in an effort to terminate its purchased power agreements, the battery was rendered useless. The Minwind interests were sold to NextEra in November 2019, to adhere to the contractual obligations of the PPA, but the turbines remained dormant and have no intention of battery use. Given the battery's age and outdated technology, the Company is retiring the asset. The battery was in-serviced with an initial life of 15 years. The Company is requesting that the Commission approve a $5.6 million reserve reallocation, within the Other function; as is noted below, the Company's proposed Other reserve reallocations will not impact customer rates.
- Wind Repowering at Nobles, Grand Meadows, Border and Pleasant Valley wind farms. Nobles was extended from November 2035 to November 2045, Grand Meadows from November 2033 to November 2043, Border from December 2040 to December 2049, and Pleasant

Valley from December 2040 to December 2049. These extensions, for the wind farms, are driven by the Company's wind farm "repowering" projects which will rebuild wind-power plants with new technology and bigger blades that will extend their life spans. Moderninzing the wind farms with new technology will increase the amount of low-cost, carbon-free wind energy the Company delivers to its customers.

For the steam production function, the notable remaining life changes were shortening the depreciable life for Allen S. King from June 2037 to December 2028 and shortening Sherco Unit 3 from December 2034 to December 2030, as I discuss further below.

Table 4 below summarizes all the generating units, in-service, for which there are changes to remaining lives.

Table 4

Production Remaining Life Changes

Functional Class/Unit	Current depreciable end of life	Proposed Remaining Life (Years) as of January 1, 2023	Expected actual retirement date
Steam Production			
A.S. King	June 2037	6.0	Dec 2028
Red Wing	Dec. 2017	5	Dec. 2027
Sherco Unit 1	Dec. 2022	4	Dec. 2026
Sherco Unit 2	Dec. 2022	1	Dec. 2023
Sherco Unit 3	Dec. 2034	8	Dec. 2030
Wilmarth	Dec. 2017	5	Dec. 2027
Other Production			
Angus Anson Units 2 & 3 (FERC 341)	May 2035	24.4	May 2045
Angus Anson Units 2 & 3 (FERC 342-346)	Oct. 2019	18	Dec. 2040
Angus Anson Unit 4	May 2035	24.4	May 2045
Black Dog Unit 5 (FERC 341)	Dec. 2031	35.3	March 2058
Blue Lake Units 1-4 (FERC 341)	May 2035	22.4	May 2045
Blue Lake Units 1-4 (FERC 342-346)	Dec. 2017	.5	June 2023
Blue Lake Units 7&8	May 2035	22.4	May 2045
Grand Meadow	Nov. 2033	20.9	Nov. 2043
Nobles	Nov. 2035	22.9	Nov. 2045
Wind-to-Battery	Dec. 2023	1	Jan. 2021

Q. ARE THERE NEW PRODUCTION ASSETS WITH NEW REMAINING LIVES?

A. Several new generation units were placed into service since the Company's last rate case. Consistent with the presentation of evidence in the applicable Infrastructure Rider proceedings, the Company is using a 25 year life for wind production assets, and the Company has established a 40 year initial life for Black Dog Unit 6 consistent with the lives assumed for the High Bridge and

Riverside Other Production plants. Table 5 summarizes the new generating units' remaining lives.

Table 5
Remaining Lives on New Production Units

Functional Class/Unit	Remaining Life at 1/1/2023 (in years)	In service Date	Proposed Retirement Date
Other Production			
Black Dog Unit 6	35.3	March-18	March-58
Pleasant Valley Wind	27.0	November-15	December-49
Border Winds	27.0	December-15	December-49
Courtenay Wind	18.9	November-16	November-41
Lake Benton Wind	21.9	November-19	November-44
Foxtail Wind	22.0	December-19	December-44
Blazing Star I Wind	22.3	April-20	April-45
Community Wind North	23.0	December-20	December-45
Jeffers Wind	23.0	December-20	December-45
Crowned Ridge Wind	23.0	December-20	December-45
Blazing Star II Wind	23.1	January-21	January-46
Mower Wind	23.3	March-21	March-46
Freeborn Wind	23.4	May-21	May-46
Dakota Range Wind	24.1	January-22	January-47
Northern Wind	25.0	December-22	December-47
Rock Aetna Wind	25.1	January-23	January-48

Q. ARE THERE ANY NEW PRODUCTION ASSETS PLANNED TO GO INTO SERVICE AFTER THE 2021 HISTORICAL TEST YEAR AND DURING THE 24-MONTH KNOWN AND MEASURABLE PERIOD?

A. Yes. There are two new wind facilities that are planned to be placed into service in 2022 and one in 2023. They include Dakota Range Wind in January of 2022, Northern Wind in December of 2022, and Rock Aetna Wind in January of 2023. The Company proposes that these production assets use a 25-year life from their respective in-service dates.

Q. IN GENERAL, WHAT CHANGES WERE MADE TO THE PRODUCTION NET SALVAGE RATES?

A. Every five years, The Company commissions a Dismantling Study to determine net salvage rates for its production assets. The Company's 2020 Dismantling Study is included as Exhibit___(LJW-1), Schedule 3, and it is a site-specific cost estimate for all of the Electric Production assets, including Hydro Production assets. The main purpose of the 2020 Dismantling Study was to estimate the present-day costs for retiring and demolishing the facilities, also known as final removals of existing facilities. A complete list of the assumptions used in the cost estimates is included in my Schedule 3.

Q. WHAT CHANGES TO THE PRODUCTION NET SALVAGE RATES ARE BEING PROPOSED?

A. Except for a few units, the general trend is toward a more negative net salvage rate due to the increasing costs of removal. The Hydro Production Hennepin Island and Upper Dam units show a slight decrease in cost of removal as well as Nobles Wind. Exhibit___(LJW-1), Schedule 5, is the comparison of present and proposed net salvage rates. To calculate the proposed negative net salvage rates, the Company took the dismantling cost estimate for the entire facility and allocated it to each unit. Once allocated to each unit, the unit dismantling cost is divided by the unit's plant balance at January 1, 2022 to get the negative net salvage rate for each unit. The proposed percent changes to the net salvage rates for production assets are summarized in Table 6 below.

Table 6

Production Net Salvage Rate Changes

Functional Class/Unit	Change in Net Salvage Rate (%)	Change in removal reserve by end of life (in millions)
Steam Production		
Allen S. King	-3.7%	$26.4
Red Wing	1.2%	$(0.8)
Sherco Unit 1	-9.9%	$76.2 (combined U1 & U2)
Sherco Unit 2	-9.9%	
Sherco Unit 3	-3.2%	$21.2
Wilmarth	-1.6%	$0.9
Hydro Production		
Hennepin Island	+3.5%	($0.7)
St. Croix Falls	-7.5%	$0.2
Upper Dam	+3.5%	($0.2)
Other Production		
Angus Anson Units 2 & 3	-6.9%	$5.9
Angus Anson Unit 4	-1.9%	$0.9
Black Dog Unit 5	-5.5%	$14.5
Blue Lake Units 1-4	-16.7%	$4.5
Blue Lake Units 7 & 8	-6.4%	$5.0
Grand Meadow Wind	-3.7%	$7.5
High Bridge	-1.1%	$4.3
Inver Hills	-9.3%	$5.4
Nobles Wind	+0.2%	($1.2)
Riverside	-7.2%	$24.0
Wind-to-Battery	-135.6%	$5.6

Q. FOR THE PRODUCTION ASSETS GOING INTO SERVICE AFTER THE 2021 HISTORICAL TEST YEAR, WHAT IS THE RECOMMENDED NET SALVAGE RATE?

A. Please see Table 7 below presenting the net salvage rates for new plants, which were not in service in the 2021 historical test year. For wind farms that weren't included in the 2020 distmantling study, the Company used a simple average of the net salvage percentages from the eight wind farms included in the 2020 Dismantling Study, which was negative 10.4 percent.

Table 7

Net Salvage Rates for New Plants

Unit	Current Net Salvage %	Proposed Net Salvage %
Black Dog Unit 6	-5.%	-10.3%
Blazing Star 1	-8.5%	-11.3%
Blazing Star 2		-10.4%
Border Winds	-6.6%	-9.5%
Community Wind		-10.4%
Courtenay Wind	-6.9%	-10.4%
Crowned Ridge Wind		-10.4%
Dakota Wind **		-10.4%
Foxtail Wind	-6.4%	-9.4%
Freeborn Wind		-10.4%
Jeffers Wind		-10.4%
Lake Benton	-8.5%	-10.5%
Mower Wind		-10.4%
Northern Wind **		-10.4%
Pleasant Valley	-8.5%	-11.7%

Q. PLEASE SUMMARIZE THE PROPOSED CHANGES TO DEPRECIATION EXPENSE FOR THE PRODUCTION ASSETS.

A. All of these changes are summarized in Table 3, above, which shows the overall \$9.2 million NSPM Total Company decrease and \$0.5 million South Dakota jurisdictional increase to depreciation expense by functional class based on plant and depreciation reserve balances as of January 1, 2023. Mr. Halama provides the revenue requirement impact of these changes for the pro forma year in his Direct Testimony.

B. Theoretical Reserve and Reserve Reallocation

Q. WHY DOES THE COMPANY PROPOSE A RESERVE REALLOCATION AND WHAT IS THE IMPACT ON DEPRECIATION EXPENSE?

A. Reserve reallocation is when the book reserve is realigned among accounts within a functional group based on the theoretical reserve for each account within that function. The Company proposes to perform a reserve reallocation in this proceeding because it results in a reduction to book depreciation expense and levelizes the impacts to customers. The proposed reallocation shifts reserves within the other and steam functions. The primary drivers for the steam and other functions' reserve reallocations are the impending expiration of depreciation expense at Sherco Units 1 & 2, shortening of the remaining life of Sherco Unit 3, and the under-recovery of the Luverne Wind2Battery asset. The reallocation is based on the theoretical reserves calculated in the Depreciation Study.

Q. WHAT IS THE THEORETICAL RESERVE IN A DEPRECAITION STUDY?

A. The theoretical reserve represents the portion of a property group's cost that would have been accrued as depreciation reserve if current expectations were used throughout the life of the property group for future depreciation accruals. The theoretical reserve for the asset group serves as a point of comparison to the book reserve to determine if the unrecovered investment of the asset and its removal cost are over or under-accrued.

Q. HOW DOES THE DEPRECIATION STUDY DETERMINE THE THEORETICAL RESERVE?

A. In the Depreciation Study, NSPM computed theoretical reserves based on projected plant balances as of December 31, 2021. The theoretical reserve was then calculated using a reserve model that relies on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. More specifically, the theoretical reserve of a property group was determined from the estimated remaining life of the group, the total life of the group, and estimated net salvage. This computation for the straight-line, remaining-life theoretical reserve ratio, which is described in more detail starting on page 19 of Exhibit___(LJW-1), Schedule 5, involves multiplying the vintage balances within the property group by the theoretical reserve ratio for each vintage. The calculation used in the Depreciation Study is the same calculation the Company used to develop the depreciation rates approved by the Commission in the Company's most recent Electric Rate Case, which was Docket No. EL14-058.

Q. HOW DOES THE THEORETICAL RESERVE RELATE TO THE RESERVE ALLOCATION?

A. As part of the Depreciation Study, a depreciation reserve reallocation was performed, which is based on the theoretical reserves calculated in the Depreciation Study. If the accumulated book depreciation reserve as compared to the theoretical reserve results in some assets being over-recovered (a positive value when subtracting the theoretical reserve from the book reserve) and others being under-recovered (a negative value when subtracting the theoretical reserve from the book reserve) within the functional class or group, then this difference can be used to rebalance the accounts within the functional class or group using the reserve reallocation.

Q. DID YOU ALIGN THE COMPANY'S DEPRECIATION RESERVE WITH THE LIFE AND NET SALVAGE CHARATERISTICS OF THE ASSETS IN EACH FUNCTION?

A. Yes. In the process of analyzing the Company's depreciation reserve, I observed that the depreciation reserve positions of the accounts were generally not in line with the life and net salvage characteristics found in the analysis of the Company's assets. To allow the relative reserve positions of each account within a function to mirror the life and net salvage characteristics of the underlying assets, I reallocated the depreciation reserves for all accounts within each function. Since the basis of the current depreciation rates incorporates different average service lives and net salvage percentages from the proposed parameters in this case, I believe reserve reallocation is the best approach based upon sound depreciation practice to resolve the differences in reserve position.

Q. DOES THE REALLOCATION OF THE DEPRECIATION RESERVE CHANGE THE TOTAL RESERVE?

A. No, the reallocation of the depreciation reserve does not change the total reserve. The depreciation reserve represents the amounts that have been collected as a systematic allocation of the cost of an asset over its useful life, including any net salvage that may be required to remove that asset from service upon retirement. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function. The reallocated depreciation reserves agree in total to the projected reserve balances at December 31, 2021.

Q. IS DEPRECIATION RESERVE REALLOCATION A SOUND PRACTICE?

A. Yes. Depreciation reserve allocation is a sound and recognized depreciation practice. The National Association of Regulatory Utility Commissioners endorsed the practice in its 1968 publication of Public Utility Depreciation Practices, explaining that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve."[2] Additionally, the 1996 edition of Public Utility Depreciation Practices states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts."[3]

With respect to the Company, Alliance's Depreciation Study demonstrates that there have been significant changes in the life and net salvage characteristics of the property since the current accrual rates were established. These changes have created a significant difference between the theoretical and the book reserve in each functional group, which makes the reallocation of the depreciation reserve appropriate in this instance.

Q. WHY IS IT IMPORTANT FOR THE DEPRECIATION RESERVE TO CONFORM TO THE THEORETICAL RESERVE?

A. It is important for the depreciation reserve to conform to the theoretical reserve because this sets the reserve at a level necessary to sustain the regulatory concept of intergenerational equity among the Company's customers, as well as sets the depreciation rates at the appropriate level based on current parameters and expectations.

Q. PLEASE EXPLAIN HOW THE REALLOCATION OF DEPRECIATION RESERVES IS CONDUCTED IN THE DEPRECIATION STUDY.

[2] Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners, at page 48 (1968).
[3] Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners, at page 188 (1996).

A. To start, the total theoretical reserve for asset groups within each function is computed. Then, to reallocate depreciation reserves within each function using the theoretical reserve model, a proration factor is computed by developing a ratio of the total book reserve to the total theoretical reserve by functional class. After each theoretical reserve was computed, it is multiplied by the proration factor to derive the reallocated book reserve of each functional group. After computing the reserve reallocation, the recommended depreciation rates and expense were calculated in Exhibit___(LJW-1), Schedules 4 and 7 for the Company's plant in service assets.

Q. ARE THERE ANY UNIQUE CIRCUMSTANCES WITH THE RESERVE REALLOCATIONS PROPOSED IN THIS PROCEEDING?

A. Yes. The primary reason the Company proposes a reserve reallocation in this proceeding is to mitigate customer rate impacts. The reserve reallocation, which most significantly mitigates customer impacts, occurs at the Sherco steam production site. As presented in Table 3 of my testimony, the current proposed change to the South Dakota jurisdictional depreciation expense, which incorporates reserve reallocations, is a reasonable $193,789.

Q. PLEASE EXPLAIN THE SHERCO SITE RESERVE REALLOCATION.

A. The Sherco site is comprised of three units: Units 1, 2 & 3. The current retirement dates for Sherco Units 1 & 2 are Dec-2022 for both units and Dec-2034 for Sherco 3. The Company is proposing to extend the remaining life at Sherco Units 1 & 2 to 2026 and 2023, respectively, and shorten the life at Sherco Unit 3 from 2034 to 2030. The Sherco Unit 3 remaining life reduction aligns with the Company's plan to retire the plant in 2030, as described further by Company witness Ms. Farah Mandich in her Direct Testimony. In this proceeding, the Company has updated remaining lives and net salvage percentages, which both directly impact depreciation expense. The impact of the proposed net salvage change for Units 1 & 2, increased from -5.1% to -15.0%, which results in an increase of $72.0 million of removal costs, and at Sherco Unit 3 an increase from -4.3% to -7.5% produces a $25.2 million increase of removal costs. These additional removal costs are reasonable and necessary to recover and properly dismantle the units. With the short proposed remaining lives at Sherco Units 1 & 2, if the Company did not perform a reserve reallocation, the $72 million would need to be recovered over a short period, which would significantly increase the Company's filed revenue requirement. This increase or spike, due to the increased removal costs and short recovery time, would ultimately flow to and increase customer rates if not remedied. To mitigate this spike, the Company proposes a reserve reallocation. The reserve reallocation shifts reserve balances from Sherco Unit 3, which has capacity and a longer recovery period, to Sherco Units 1 & 2. The removal cost recovery of the $72 million, formerly responsible for Units 1 & 2 in the short-term, will be assigned to Sherco Unit 3, which has a longer remaining life to recover over. By shifting reserve balances, the Company achieves its objectives to "smooth" the depreciation expense and mitigate customer rate spikes. The $72 million of removal costs will be recovered; the Company is simply proposing to vary the timeline of the recovery in order to mitigate customer rate impacts.

Q. ARE THERE ANY OTHER FACTORS THAT SUPPORT THE COMPANY'S PROPOSED RESERVE REALLOCATION AT SHERCO?

A. Yes. From a practical perspective, it makes sense to reallocate the reserves and removal cost recovery as described above because while the plant contains three separate units, the Sherco facility is a single generating station. The turbines for the different Sherco Units are all immediately adjacent to one another on the same floor in the same building, meaning it would be virtually impossible to decommission and dismantle Sherco Units 1 & 2 without decommissioning Sherco Unit 3 as well. Therefore, it is reasonable to reallocate the reserve in order to recover the remaining costs from a view of the life of the entire Sherco generating station, because the facility will not be dismantled until the final unit (Unit 3) retires.

Q. ARE THERE ANY ADDITIONAL RESERVE REALLOCATIONS PROPOSED IN THIS PROCEEDING?

A. Yes. There are a few, much less material reserve reallocations in the Steam Production and Other Production functions to ensure full recovery of the plant and removal costs without impact to customer rates.

C. TD&G Assets

Q. WHAT ARE TD&G ASSETS?

A. TD&G assets refer to all assets in the transmission, distribution, and general functional classes of assets. General assets can be either electric utility only (e.g. communication equipment which specifically supports only the electric segment) or common utility (e.g. a service truck which can be deployed to support either gas or electric repairs). Common utility assets are allocated out to the electric and gas segments based on various allocation methods.

Q. WHAT IS THE PURPOSE OF A TD&G DEPRECIATION STUDY?

A. A depreciation study is a comprehensive analysis of all TD&G assets in order to determine the statistical parameters for each account or group of assets to set depreciation rates and lives. The depreciation study encompasses four distinct phases. The first phase involves data collection and field interviews. The second phase is an initial data analysis. The third phase evaluates the information and analysis. Finally, the fourth phase involves the calculation of depreciation rates and documents the corresponding recommendations.

Q. WHEN WAS A TD&G DEPRECIATION STUDY LAST PERFORMED?

A. The Company directed Alliance Consulting Group to perform a comprehensive Depreciation Study (2017 Alliance Study) for the TD&G assets for the electric, gas, and common utilities. This study is performed every 5 years so the next study will be performed in 2022. Although gas assets were included in the 2017 Alliance Study, they are not part of this proceeding. All Company assets were included in the 2017 Alliance Study regardless of where they were located. The 2017 Alliance Study is included as Exhibit___(LJW-1), Schedule 6.

In the 2017 Alliance Study, the Company reviewed the depreciable lives and net salvage rates for TD&G assets. The analysis included interviews with operating personnel responsible for purchase, maintenance, and utilization of the equipment. For the 2017 Alliance Study, the lives were adjusted if factors such as market forces, manufacturer expected life, technological obsolescence, business planning, known causes of retirement, and changes in expected future utilization affected the useful life of the asset.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ANALYSIS THAT WAS DONE TO DETERMINE DEPRECIATION RATES FOR TD&G ASSETS.

A. The 2017 Alliance Study was only used for the resulting statistics (average service life, net salvage rate, and retirement curve) and not for the determination of the depreciation rate. The calculation of the average remaining life depreciation rate was done by Company personnel using the South Dakota depreciation reserve in conjunction with the depreciation statistics from the 2017 Alliance Study. The 2017 Alliance Study is included as Exhibit__(LJW-1), Schedule 6. Exhibit__(LJW-1), Schedule 7, compares the presently approved depreciation rates and parameters to the proposed values. The depreciation rate calculation is shown in Exhibit__(LJW-1), Schedule 8.

As a result of the comprehensive 2017 Alliance Study, the Company proposes new depreciation lives, net salvage rates, retirement curves, and depreciation rates for TD&G assets in this filing to better reflect the expected useful lives of its assets as well as removal costs and expected salvage. In general, depreciation lives are lengthening slightly and net salvage rates are becoming more negative, with the exception of FERC Accounts 392 and 396, due to increasing removal costs and decreasing gross salvage values. The Company also continues the use of an Average Remaining Life (ARL) method. This method allows an automatic true-up of differences created between the theoretical and actual reserves over the remaining lives of the assets.

Q. AS A RESULT OF THE 2017 ALLIANCE STUDY, WHAT CHANGES TO ELECTRIC TRANSMISSION AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For electric transmission accounts, the lives for half of the accounts increased. There are seven accounts, three that have increasing lives, one that had a decreasing life, and the lives of the other three accounts were unchanged. The account with the greatest change in life is FERC Account 354, Transmission Towers and Fixtures, which increased by five years. There is also a trend toward higher negative net salvage, with five accounts increasing (i.e., more negative) and their negative net salvage and the remaining two accounts remaining unchanged. The account with the largest increase in negative net salvage is FERC Account 355, Poles and Fixtures, where the net salvage moved from negative 35 percent to negative 50 percent. The increased cost of removal is primarily due to union wage increases. There is a new account included for the first time, FERC Account 359, Roads and Trails. There are currently no assets in this account; it was added in anticipation of future additions. The average service life was set at 60 years with a zero net salvage rate.

Q. WHAT CHANGES TO ELECTRIC DISTRIBUTION AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. There are 12 existing electric distribution accounts, of which six have increasing lives, one has a decreasing life, and the lives of the other five accounts are unchanged. The accounts with the greatest change in life are FERC Account 366, Underground Conduit, and FERC Account 367, Underground Conductor and Devices, both of which moved four years longer in life. There is also a trend toward higher negative net salvage with eight accounts increasing (i.e., more negative) their negative net salvage, one account decreasing its negative net salvage, and the remaining three accounts remaining unchanged. The account with the largest increase in negative net salvage is FERC Account 364 Distribution Poles, Towers, and Fixtures where the net salvage moved from negative 100 percent to negative 120 percent. This is similar to the increased cost of removal in Transmission. The analysis of distribution assets used only South Dakota located assets. There are three new depreciation sub-accounts added to FERC Accounts 369 and 370 which are intended to support electric vehicles and AGIS. Currently there is no balance in these accounts. In the event plant is added to these accounts, the Company requests authorization to use average lives of 10 years for FERC Account 369 Electric Vehicle Supply Infrastructure, 20 years for FERC Account 370 Meters - AGIS plant, and 10 years for FERC Account 370 Electric Vehicle Chargers. No net salvage rates are expected for these assets, as any costs of removal are expected to be offset by salvage.

Q. WHAT CHANGES TO ELECTRIC GENERAL AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For electric general accounts, the lives for most of the accounts remained the same. There are 18 accounts, four that have increasing lives, four that have decreasing lives, and the lives of the other 10 accounts were unchanged. The account with the greatest change in life is FERC Account 392.3, Trailers, which moved three years shorter in life. There is also a slight trend toward higher positive net salvage with five accounts increasing their positive net salvage and the remaining 13 accounts remaining unchanged. The account with the largest increase in positive net salvage is FERC Account 392.3, Trailers, where the net salvage moved from zero percent to positive 20 percent.

Q. WHAT CHANGES TO COMMON GENERAL AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For common general accounts, the lives for most of the accounts remained the same. There are 15 existing accounts, three that have increasing lives, four that have decreasing lives, and the lives of the other eight accounts were unchanged. The account with the greatest decrease in life is FERC Account 390, Structures and Improvements, which moved five years shorter in life. There is also a slight trend toward higher positive net salvage with five accounts increasing their positive net salvage, one account increasing its negative net salvage, and the remaining ten accounts remaining unchanged. The account with the largest increase in positive net salvage is FERC Account 392.3, Trailers, where the net salvage moved from zero percent to positive 20 percent. The account with the largest increase in negative net salvage is FERC Account 390, Structures and Improvements, where the net salvage moved from negative 20 percent to negative 25 percent.

Additionally, the Company is proposing a new subaccount under FERC Account 397 Communication Equipment for Smart Grid assets, specifically, the Field Area Network (FAN) equipment which supports the Meter Replacement program. The Company is proposing a 10-year Average Service Life with a zero net salvage percent, which means that the expected salvage will equal the cost to remove the equipment. This is consistent with the current parameters of other similar communication assets. These assumptions result in a 10.00 percent initial depreciation rate.

Q. WHAT OTHER PROPOSED CHANGES TO COMMON GENERAL, IN THIS PROCEEDING, WOULD YOU LIKE TO DISCUSS?

A. In compliance with a December 13, 2019 Order issued by the Minnesota Public Service Commission (MPUC), the Company has completed a review of the building assets included in FERC Account 390 – Structures and Improvements – in order to determine which assets should continue to be group depreciated and which assets should be separately depreciated. As part of the review and in response to a request from the Minnesota Department of Commerce, the Company has separately accounted for depreciation for the small number of "high-value" buildings in FERC Account 390, the retirement of which "could have a significant impact on the depreciation expense of the account as a whole."

Q. WHAT CHANGES TO ELECTRIC AND COMMON INTANGIBLE AVERAGE SERVICE LIVES AND NET SALVAGE RATES ARE BEING PROPOSED?

A. For both electric and common intangible accounts, no life or net salvage changes are recommended to existing accounts. FERC Account 302, Franchises and Consents, has been added to the schedules, and these assets are amortized over the term of the individual franchise agreements. Also, a new sub account for FERC Account 303, Software, was added for the new large base computer systems for the General Ledger and Work and Asset Management. This group has a proposed average life of 15 years. Common intangible had previously approved categories of three, five, seven, and ten year lives. Electric intangible only had a five-year life category. Therefore, the Company is adding new sub accounts to the electric utility so each utility has the categories of three, five, seven, ten, and fifteen year lives in anticipation of future additions.

Q. IS THE COMPANY PROPOSING TO CONTINUE THE USE OF AVERAGE REMAINING LIFE DEPRECIATION RATES FOR TD&G?

A. Yes.

IV. NUCLEAR DECOMMISSIONING TRUST

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section addresses the changes to the calculation of the nuclear decommissioning accrual that have occurred since the the Company's last rate case, filed in 2014. There is a new engineering cost estimate, updated escalation and earnings rates, current bank balances, and elimination of the Escrow Fund that must now be reflected in current rates.

Q. WHAT IS THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. Nuclear decommissioning accrual is the method used to accumulate the final removal costs for the Company's three nuclear units. The amounts collected through general rates are deposited externally in a trust fund per Nuclear Regulatory Commission (NRC) rules. The annual accruals are calculated from a detailed engineering cost estimate for removal of the plant and of storage of the fuel until the federal government takes possession of all the fuel assemblies. These accruals are then invested by professional asset managers in a risk-mitigating strategy to grow the accrued amount while hedging losses.

This is in contrast to how the Company addresses dismantling costs for its other production assets, where the dismantling costs are not segregated into a trust account nor invested.

Q. WHAT CHANGES ARE YOU RECOMMENDING?

A. The Company is proposing to increase the annual nuclear decommissioning accrual for the South Dakota jurisdiction from $1,234,251 set in Docket EL12-046 to $8,192,630. Nuclear decommissioning accruals are calculated at the jurisdictional level and not at the total NSPM Company level. This accrual is calculated for a 60-year DECON scenario, which is in line with NSPM's other jurisdictions, and is the industry requirement from the NRC.

Q. HOW IS THE NUCLEAR DECOMMISSIONING ACCRUAL AMOUNT DETERMINED?

A. Using an engineering cost study for the basis of decommissioning costs, the Company partners with Goldman Sachs Asset Management (GSAM), the trust fund administrators, to obtain labor and non-labor escalation rates as well as operational and post-shutdown earning rates on the fund for each of the nuclear units throughout the decommissioning of each facility.

Q. WHAT IS CAUSING THE NUCLEAR DECOMMISSIONING ACCRUAL TO INCREASE?

A. The increase is driven primarily by an increase in the estimate of removal costs. The current accrual was approved in the 2012 rate case, and was based upon the 2011 cost study. This proceeding uses the 2020 cost estimate. The study was performed in 2020 and provided costs in 2020 dollars. Both studies were prepared by TLG Services, the engineering consultant the Company has historically used to prepare these estimates. TLG Services has extensive industry experience and currently provides estimates for the majority of nuclear production plants in the country. A comparison of the nominal cost estimates to decommission are in Table 8 below. Additionally, there was a decrease in the earnings assumption of the trust.

Table 8
Nominal Cost Estimate to Decommission

Year of Study	Monti	PI1	PI2	Total
2011	$ 1,163,818,832	$ 700,574,802	$ 832,756,232	$ 2,697,149,866
2020	$ 1,612,762,003	$ 1,017,864,701	$ 1,029,940,789	$ 3,660,567,493
Change in Estimate	**$ 448,943,171**	**$ 317,289,899**	**$ 197,184,557**	**$ 963,417,627**

Q. WHAT EARNINGS AND ESCALATION RATES ARE BEING USED TO CALCULATE THE NUCLEAR DECOMMISSIONING ACCRUAL?

A. The accrual calculation is run on each unit using two single effective earnings rates, one rate for the operating period (radiological) and one for the post-shutdown period (spent fuel/site restoration). These rates, which reflect the anticipated amount of investment proceeds the Company expects to earn on the funds in trust, are calculated and provided by GSAM, based on asset allocation recommendations made at the same time as the development of the 2020 cost estimate. The operating period rates are 3.92 percent for Monticello, down from 5.35 percent in 2011; 3.94 percent for Prairie Island Unit 1, down from 5.50 percent in 2011; and 4.02 percent for Prairie Island Unit 2, down from 5.53 percent in 2011. The post shutdown period rates are 3.30 percent for Monticello, down from 4.82 percent in 2011; 2.98 percent for Prairie Island Unit 1, down from 4.66 percent in 2011; and 2.90 percent for Prairie Island Unit 2, down from 4.57 percent in 2011. Cost escalation rates were also provided by GSAM. The cost escalation rates in the 2020 study are 4.22 percent for labor costs and 3.02 percent for non-labor costs. This is not directly comparable to the Operations rate of 3.63 percent and the post decommissioning rate of 2.63 percent that was used in the 2011 study, but it uses the same base assumptions around inflation and wage increase rates.

Table 9

Earnings Rates Changes

Nuclear Unit	Period	2011 Return	2020 Return	Change
Monticello	Pre-decommission start	5.35%	3.92%	-1.43%
Monticello	Post-decommission start	4.82%	3.30%	-1.52%
PI Unit I	Pre-decommission start	5.50%	3.94%	-1.56%
PI Unit I	Post-decommission start	4.66%	2.98%	-1.68%
PI Unit II	Pre-decommission start	5.53%	4.02%	-1.51%
PI Unit II	Post-decommission start	4.57%	2.90%	-1.67%

Q. WHAT IS THE BALANCE FOR SOUTH DAKOTA IN THE QUALIFIED TRUST?

A. The accrual calculation uses qualified trust balances as of December 31, 2021. The market value of the fund, net of expected taxes on unrealized gains, for each unit for the South Dakota jurisdiction issued as a starting point for each unit's accrual calculation. Exhibit_LJW, Schedule 9, shows the balances of the funds as of December 31, 2021 used to calculate the accrual, and Table 10 shows the balance by unit.

Table 10
Qualified Trust Fund Balance by Unit
June 30th, 2020

Monticello	$1,076,666,911
Prairie Island 1	622,498,987
Prairie Island 2	695,439,515
Total	$2,394,605,413

Consistent with the Company's 2012 Filing in Docket No. EL12-046 regarding the then-existing nuclear decommissioning escrow account, the beginning balance of the trust also includes the pour-over of the then-existing escrow funds. In addition to the South Dakota jurisdictional fund balances, past wholesale balances are expected to be reallocated across all jurisdictions. When this reallocation occurs, South Dakota will realize a benefit for these dollars as they impact the beginning balance of future decommissioning accruals.

Q. DOES THE COMPANY'S TREATMENT OF THE NUCLEAR DECOMMISSIONING ACCRUAL REQUESTED IN THIS PROCEEDING ALIGN IT WITH ITS OTHER JURISDICTIONS?

A. Yes. The Company is currently using the 2017 Triennial Nuclear Decommissioning proceeding in Minnesota (Docket No. E002/M-17-828, submitted December 1, 2018) as the basis for the nuclear decommissioning accrual in Minnesota. This study was adjusted in the 2019 Integrated Resource Plan to integrate the effects of the DOE refunds. The Company believes the same outcome should be used in South Dakota as well.

Q. WHAT IS THE DEPARTMENT OF ENERGY (DOE) REFUND?

A. These are payments related to the DOE's partial breach of its contract to begin accepting spent nuclear fuel beginning on or before January 31, 1998. Under settlement, the DOE has agreed to pay for costs associated with its failure to begin taking spent fuel in 1998 including: a) any additional pool storage costs and other plant modifications; b) dry casks storage and costs directly related to such storage (e.g., internal labor, overhead, operation and maintenance, training and security); and c) additional property taxes resulting from the on-site dry cask storage or other plant modifications. The Company has historically refunded the amount paid by the DOE under this settlement to customers in the year received.

Q. PLEASE SUMMARIZE THE INTERACTION OF THE ACCRUAL AND THE DOE SETTLEMENT PAYMENTS FOR THE SOUTH DAKOTA JURISDICTION.

A. Currently, the DOE settlement payments allocated to South Dakota are being refunded to customers as received. In other jurisdictions, these amounts have been used to offset accrual increases and avoid rate increases. The Company is proposing in this case to utilize projected future DOE reimbursements after shutdown to offset the expected costs associated with spent fuel disposal within the NDT accrual. The Company has incorporated the DOE offset using a 75 percent scenario. This percentage designates how much of the future expected spent fuel costs will be offset by DOE reimbursements. In the amounts calculated for this case, the Company is assuming a 75 percent scenario as a conservative approach; the recommended range could include up to 90 percent of the DOE reimbursements. The Company used a third-party consultant[4] in the 2017 Triennial Nuclear Decommissioning to validate that the Company's inclusion of these funds is reasonable.

Q. WHAT IS THE END-OF-LIFE (EOL) NUCLEAR FUEL ACCRUAL?

A. The EOL Accrual is a cost recovery mechanism that reserves for the unspent and unamortized nuclear fuel that is in the reactors at the time the nuclear reactors are shut down. These reserves accrete over the life of the plant through a periodic expense, similar to other end of life and removal reserves.

Q. HOW DOES THE END-OF-LIFE (EOL) NUCLEAR FUEL ACCRUAL WORK?

A. The EOL Accrual and Decommissioning Accrual both function by setting funds aside for known future obligations. However, the EOL Accrual is different in that its funds are held within the Company as opposed to a separate trust. Because of this, there is an offset to rate base for the cumulative EOL funding. Customers receive offsetting benefit from this funding through a reduction in rate base and in the resulting reduction in general rates.

The intent of EOL recovery is that the cumulative effect of the accrual and corresponding rate base reduction will maintain a constant annual net cost to customers over time. The EOL rate base reduction and accruals collected are

[4] Adam Levin is a sole proprietor doing business as AHL Consulting, delivering consulting services to the commercial nuclear power industry and the U.S. Department of Energy, providing expertise in all areas of decommissioning and spent nuclear fuel (SNF) management strategy, operations and finances.

put into rates in the Company's general rate case filings. At that point both are in parity – meaning that for the first year the customer pays the full accrual amount and receives the full benefit of the rate base impact through rates. However, in future years the customer needs to be compensated for the additional offset to rate base that it should receive for the contributions it has made since the general rate was approved. To compensate for this, the assumed accrual increases to an amount that includes the rate base impact the customer should receive. In this way, the customer is credited for the benefit they should receive by essentially investing the assumed return into the EOL fund balance. As such, every year that passes, the assumed accrual will increase without an increase to rates, to compensate for the assumed interest until another general rate case is filed and ordered on. At this point, the higher accrual is put into rates, offset by a larger rate base offset.

In summary, the EOL Accrual increases annually without an increase in rates as a result of the compensating effect of the assumed interest on the rate base reduction. This process resets or rebalances every time a new general rate case is filed where the rate base benefit is adjusted to reflect the past amount contributed.

Q. IS THE COMPANY PROPOSING A REVISION TO THE EOL NUCLEAR FUEL ACCRUAL IN THIS CASE?

A. Yes. Based on updated assumptions around the cost of fuel and the how the fuel will be used in the reactors, the amount the Company needs to recover has decreased from the last approved filing. In the 2020 Triennial Filing, this accrual was approved for $1,042,656 effective in 2023.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company has made considerable investments in the NSP System since the last rate case was filed in 2014 to help maintain safe, reliable, and affordable electric service to its customers. Many of these investments have already been deemed prudent by the Commission in various proceedings, and those that have not are prudent.

The Company must update its depreciation expense given the passage of time since its last rate case. The changes in its depreciation expense are consistent with current known and assumed remaining lives of its production plant, currently known net salvage rates, and other considerations. Additionally, the Company's proposed TD&G depreciation rates are consistent with appropriate studies and conform to past practice. Overall, the Company's proposed depreciation rates are reasonable and should be approved by the Commission.

Also given the passage of time since its last rate case, the Company must increase amounts accrued to fund the Nuclear Decommissioning Trust. The costs to fund the trust are a necessary component of providing the benefits of a strong nuclear fleet to our customers, are reasonable, and should be approved by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Laurie J. Wold

I received a Bachelor of Arts in Business Administration, with a major in accounting, from Metropolitan University in 2011.

My current position with XES is Senior Manager, Capital Asset Accounting. I am responsible for:

- Managing the capital investment cost recovery process, which includes the development of detailed actuarial analysis, regulatory filings with the various state and federal rate regulatory commissions, and expert testimony to support recovery levels in rate proceedings;
- Accounting for and reporting on the nuclear plant decommissioning funding process, which includes the development of detailed engineering cost studies combined with a complete financial and economic analysis to develop detailed regulatory filings to establish the ratepayer funding levels necessary to accumulate the total future decommissioning cost requirement;
- Assisting with the plant asset-related ratemaking process, which supports the rate filings for all of the Xcel Energy Operating Companies' retail and wholesale jurisdictions; and
- Overseeing capital asset reporting and information processing necessary to disseminate capital asset information as required by various regulatory authorities (the Federal Energy Regulatory Commission, the Securities and Exchange Commission, and state commissions) as well as meeting all internal information requirements necessary to sustain efficient and effective business operations.

I first worked for XES as a contract Accountant starting in October 2011, until I took a permanent role in Transmission Finance in April 2012. I held various positions in Transmission Finance until 2017; since then I have been in my current position in Capital Asset Accounting.

Prior to joining XES, I was employed by USA Today as an Accounting Supervisor. Prior to USA Today, I was employed in various industries in a financial capacity.

NSPM- SD
Plant Rollforward 2014- 2021

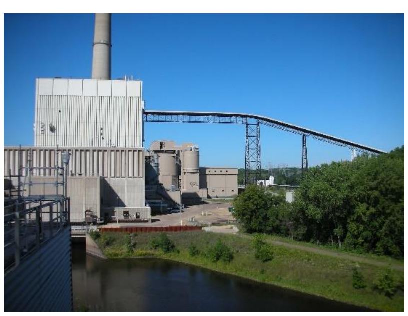
Functional Class	2014	2015	2016	2017	2018	2019	2020	2021
Electric Intangible Plant								
Plant Beginning Balance	256,248,348	317,993,623	361,032,363	363,189,703	360,945,912	389,110,261	398,408,529	400,884,072
Plant Additions	61,745,275	49,193,938	2,157,341	5,346,669	37,617,867	13,693,611	4,290,617	48,060,743
Retirements	-	-6,155,198	-	-7,590,460	-9,453,519	-4,395,343	-1,815,074	-2,327,510
Transfers & Adjustments	-	-	-	-	-	-	-	-
Plant Ending Balance	317,993,623	361,032,363	363,189,703	360,945,912	389,110,261	398,408,529	400,884,072	446,617,305
Electric Nuclear Production Plant								
Plant Beginning Balance	3,042,781,802	3,144,036,630	3,373,254,400	3,472,286,167	3,585,739,575	3,833,961,553	3,899,416,701	3,942,163,350
Plant Additions	118,048,258	235,198,430	128,709,868	130,850,218	262,433,822	85,950,847	60,268,357	86,383,375
Retirements	-16,793,430	-5,980,659	-29,678,101	-17,396,810	-12,920,265	-21,000,557	-17,521,709	-1,582,585
Transfers & Adjustments	-	-	-	-	-1,291,580	504,859	-	-
Plant Ending Balance	3,144,036,630	3,373,254,400	3,472,286,167	3,585,739,575	3,833,961,553	3,899,416,701	3,942,163,350	4,026,964,139
Electric Steam Production Plant								
Plant Beginning Balance	2,288,819,845	2,344,209,827	2,238,603,866	2,263,126,246	2,286,997,337	2,326,649,555	2,326,122,491	2,347,387,469
Plant Additions	83,751,550	70,589,641	38,807,184	38,138,096	60,945,257	13,634,972	39,521,029	40,398,693
Retirements	-28,361,568	-93,334,361	-4,868,230	-13,900,625	-21,127,816	-13,191,935	-8,158,854	-7,648,792
Transfers & Adjustments	-	(82,861,241)	(9,416,573)	(366,381)	-165,222	-970,101	(10,097,197)	-
Plant Ending Balance	2,344,209,827	2,238,603,866	2,263,126,246	2,286,997,337	2,326,649,555	2,326,122,491	2,347,387,469	2,380,137,370
Electric Hydro Production Plant								
Plant Beginning Balance	25,352,768	25,220,080	27,028,345	27,244,200	27,285,875	27,621,374	27,700,117	27,882,287
Plant Additions	236,760	1,808,265	215,855	42,934	602,497	21,619	202,662	14,381
Retirements	-369,447	-	-	-1,259	-266,998	-	-20,492	-1,118
Transfers & Adjustments	-	-	-	-	-	57,124	-	-
Plant Ending Balance	25,220,080	27,028,345	27,244,200	27,285,875	27,621,374	27,700,117	27,882,287	27,895,551
Electric Other Production Plant								
Plant Beginning Balance	1,853,070,182	1,859,426,378	2,547,852,910	2,852,809,179	2,857,207,483	2,972,277,974	3,385,778,166	4,128,924,232
Plant Additions	10,963,560	613,900,202	299,643,713	13,871,404	121,292,465	427,303,109	756,579,235	931,067,950
Retirements	-4,309,527	-8,358,911	-4,104,017	-9,935,514	-6,363,815	-14,807,032	-23,530,366	-11,630,266
Transfers & Adjustments	(297,837)	82,885,241	9,416,573	462,414	141,841	1,004,115	10,097,198	(14,802)
Plant Ending Balance	1,859,426,378	2,547,852,910	2,852,809,179	2,857,207,483	2,972,277,974	3,385,778,166	4,128,924,232	5,048,347,115
Electric Transmission Plant								
Plant Beginning Balance	2,260,295,093	2,835,356,378	3,293,741,914	3,475,978,713	3,592,445,530	3,702,377,186	3,795,878,039	3,919,326,875
Plant Additions	577,634,932	470,888,949	182,402,595	146,364,297	126,966,322	99,163,081	142,312,089	279,327,873
Retirements	-2,076,729	-12,556,673	-165,797	-29,897,479	-16,621,182	-8,229,640	-18,875,092	-8,778,549
Transfers & Adjustments	(496,918)	53,260	-	0	-413,484	2,567,412	11,839	14,802
Plant Ending Balance	2,835,356,378	3,293,741,914	3,475,978,713	3,592,445,530	3,702,377,186	3,795,878,039	3,919,326,875	4,189,891,001
Electric Distribution Plant - SD only								
Plant Beginning Balance	222,590,371	250,875,872	277,617,508	298,071,330	312,543,312	322,590,874	338,205,133	347,003,171
Plant Additions	15,181,109	28,169,006	21,041,394	16,658,331	15,790,693	18,700,216	13,332,406	21,775,992
Retirements	-1,222,965	-1,427,370	-587,573	-2,186,349	-5,743,131	-2,992,300	-4,534,367	-1,133,312
Transfers & Adjustments	14,327,358	-	-	-	-	-93,657	-	-
Plant Ending Balance	250,875,872	277,617,508	298,071,330	312,543,312	322,590,874	338,205,133	347,003,171	367,645,852
Electric General Plant								
Plant Beginning Balance	337,663,954	370,627,358	438,665,635	489,399,248	545,505,161	593,741,596	627,386,334	662,185,961
Plant Additions	38,796,829	74,421,053	58,472,597	65,714,437	55,662,967	39,851,275	44,977,850	103,892,739
Retirements	-5,833,425	-6,382,776	-7,738,984	-9,512,490	-8,634,539	-4,528,911	-10,166,384	-39,731,413
Transfers & Adjustments		-	-	(96,034)	1,208,007	-1,677,626	(11,839)	2,217,581
Plant Ending Balance	370,627,358	438,665,635	489,399,248	545,505,161	593,741,596	627,386,334	662,185,961	728,564,868
Nuclear Fuel								
Plant Beginning Balance	2,093,211,530	2,156,234,097	2,298,523,728	2,366,244,703	2,514,999,100	2,597,079,745	2,754,625,024	2,833,871,244
Plant Additions	63,022,567	142,289,631	67,720,975	148,754,396	82,080,645	157,545,279	79,246,220	146,056,840
Retirements	-	-	-	-	-	-	-	-
Transfers & Adjustments	-	-	-	-	-	-	-	-
Plant Ending Balance	2,156,234,097	2,298,523,728	2,366,244,703	2,514,999,100	2,597,079,745	2,754,625,024	2,833,871,244	2,979,928,084
Total Electric Utility	13,303,980,244	14,856,320,670	15,608,349,488	16,083,669,285	16,765,410,118	17,553,520,534	18,609,628,661	20,195,991,284
Common Intangible Plant								
Plant Beginning Balance	239,276,779	293,118,141	326,196,864	378,920,757	370,147,918	432,694,045	469,491,574	513,593,465
Plant Additions	54,708,510	38,752,935	58,837,506	113,715,066	54,201,092	51,623,842	47,702,519	60,562,086
Retirements	-867,148	-5,674,212	-6,113,612	-122,487,905	8,345,036	-14,826,313	-3,600,628	-7,614,900
Transfers & Adjustments	-	-	-	-	-	-	-	-
Plant Ending Balance	293,118,141	326,196,864	378,920,757	370,147,918	432,694,045	469,491,574	513,593,465	566,540,651
Common General Plant								
Plant Beginning Balance	256,611,579	266,465,573	287,834,644	321,868,061	339,863,914	359,306,007	405,732,065	427,142,765
Plant Additions	29,714,591	32,459,254	50,180,646	38,894,171	37,572,680	58,663,306	48,682,370	44,254,328
Retirements	-19,860,597	-11,090,182	-16,147,229	-20,898,318	-18,150,582	-10,081,174	-27,271,670	-48,247,730
Transfers & Adjustments	-	-	-	-	19,995	-2,156,074	-	-2,217,581
Plant Ending Balance	266,465,573	287,834,644	321,868,061	339,863,914	359,306,007	405,732,065	427,142,765	420,931,781
Total Common Utility	559,583,714	614,031,508	700,788,819	710,011,832	792,000,053	875,223,638	940,736,230	987,472,432
Total Electric Utility and Common Utility	13,863,563,958	15,470,352,178	16,309,138,307	16,793,681,118	17,557,410,170	18,428,744,173	19,550,364,891	21,183,463,716

Document X01-1776-001, Rev. 0

DISMANTLING COST STUDY
for

Allen S. King Unit 1
Angus Anson Units 1-4
Black Dog Units 2, 3, 5 and 6
Blue Lake Units 1-4, 7 and 8
Granite City Units 1-4
Hennepin Island
High Bridge Units 1-3
Inver Hills Units 1- 6
Key City Units 1-4
Maplewood Gas Plant
Minnesota Valley Units 1-3
Red Wing Units 1 & 2
Riverside Units 7, 8, 9 and 10
Sherburne County Units 1-3
Sibley Gas Plant
Wescott Gas Plant
Wilmarth Units 1 & 2
Stations

Blazing Star I Wind Farm
Border Winds Project
Courtenay Wind Farm
Foxtail Wind Farm
Grand Meadow Wind Farm
Lake Benton II Wind Farm
Nobles Wind Farm
Pleasant Valley Wind Farm



prepared for

Xcel Energy

prepared by

TLG Services, Inc.
An Entergy Company

148 New Milford Road East
Bridgewater, CT

April 2020

APPROVALS

Project Engineer	Benjamin J. Stochmal **Benjamin J. Stochmal**	4/1/20 **Date**
Project Engineer	Timothy A. Arnold **Timothy A. Arnold**	4/1/2020 **Date**
Project Manager	Roderick Knight **Roderick Knight**	4/1/2020 **Date**
Technical Manager	Francis W. Seymore **Francis. W. Seymore**	4/1/2020 **Date**

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

SECTION **PAGE**

TABLE OF CONTENTS
(continued)

SECTION **PAGE**

TABLES

TABLE OF CONTENTS
(continued)

SECTION **PAGE**

TABLES
(continued)

FIGURES

APPENDICES

REVISION LOG

Rev. No.	CRA No.	Date	Item Revised	Reason for Revision
0		04/01/2020		Final Issue

ACRONYMS / DEFINITIONS

AIF	Atomic Industrial Forum
CT	Combustion Turbine
CCGT	Combined Cycle Gas Turbine
DOC	Decommissioning Operations Contractor
DOE	Department of Energy
HRSG	Heat Recovery Steam Generator
LS	Lump Sum
Mtr	Motor
MV	Medium Voltage
Mw	Megawatt
MWe	Megawatt (electric) – 2020 Net Max. Capacity (NMC) Rating
NESP	National Environmental Studies Project
NG	Natural Gas
OSHA	Occupational Safety & Health Administration
PCB	Polychlorinated Biphenyl
RDF	Refuse Derived Fuel
TLG	TLG Services, Inc.
WTG	Wind Turbine Generator

EXECUTIVE SUMMARY

This report, prepared by TLG Services, Inc. (TLG), provides estimated costs for the complete dismantling, unless otherwise specified, of the following electric generating stations, wind farms, gas storage and production plants operated by Xcel Energy (Xcel), which either owns or has a share in ownership in each of these facilities:

Generating Stations Located in Minnesota:
- Allen S. King
- Black Dog
- Blue Lake
- Granite City
- Hennepin Island
- High Bridge
- Inver Hills
- Key City
- Minnesota Valley
- Red Wing
- Riverside
- Sherburne County
- Wilmarth

Generating Station Located in South Dakota:
- Angus Anson

Gas production and storage plants (all located in Minnesota):
- Maplewood
- Sibley
- Wescott

Wind Farms Located in Minnesota:
- Blazing Star I Wind Farm
- Grand Meadow Wind Farm
- Lake Benton II Wind Farm
- Nobles Wind Farm
- Pleasant Valley Wind Farm

Wind Farms Located in North Dakota:
- Border Winds Project
- Courtenay Wind Farm
- Foxtail Wind Farm

The dismantling estimate includes the cost of removing the equipment and structures for each of the above-referenced facilities and limited restoration of the sites. The electrical switchyards are assumed to remain in place and are not included in the estimate.

The scope of the dismantling estimate includes the following significant work activities and labor, equipment, material, and waste disposal cost elements:

- Preparation of the units for safe dismantling
- Abatement of asbestos containing materials prior to dismantling (where applicable)
- Removal and disposition of all installed equipment (except where noted)
- Demolition and disposition of subsurface utilities and buildings and foundations (except where noted)
- Removal of below grade foundations (except where noted)
- Coal yard and ash pond remediation (Sherburne County, King, and Minnesota Valley)
- Limited site restoration (grading and seeding for drainage and erosion control)
- Demolition contractor's on-site management, engineering, safety, and administrative staff
- Demolition contractor's expenses, including profit, insurance, permits, and fees
- Xcel's on-site management, oversight, and security staff
- A cost credit associated with the disposition of scrap metals
- Cost contingency

The general approach in assembling the estimate was to develop an inventory of equipment and structures designated to be removed for each facility. This inventory was established using site walk-downs (including discussions with the Operations & Maintenance staff), station-provided equipment databases, and plant drawings. This inventory accounted for similarities between facilities.

The abatement, removal, demolition and restoration activity costs are estimated by applying unit cost factors (developed for each inventory item) against the inventory. Costs for project management, shared equipment and consumables, and similar types of costs are estimated on a period-dependent basis (i.e., the magnitude of the expense depends, in part, on the duration of the project and the types of activities taking place). The potential value of scrap from materials generated in dismantling the plant components and building structural steel is included as a credit in the dismantling cost estimate. Contingency is provided within this estimate to account for unpredictable project events.

OSHA states that demolition involves additional hazards due to unknown factors which make demolition work particularly dangerous. OSHA further states that the hazards of demolition work can be controlled and eliminated with the proper planning, the right personal protective equipment, necessary training, and compliance with OSHA standards. This cost estimate is intended to provide sufficient monies to allow Xcel management to perform the project using these principles and standards.

The dismantling costs, expressed in thousands of 2019 dollars, are provided in the following table.

SUMMARY OF DISMANTLING COSTS
(All costs are in thousands of 2019 dollars)

Station	Unit	MWe rating	Type	Fuel	In Service	Station Cost
Electric Generation Facilities –Fossil and Hydro						
Allen S. King	1	511	Steam	Coal	1968	65,755
Angus Anson	1		Steam	N/A	1966	12,727
	2	109	CT	NG/Oil	1994	
	3	109	CT	NG/Oil	1994	
	4	168	CT	NG/Oil	2005	
Black Dog	2	117	Steam	(note 1)	1952	48,729
(Unit 3 Retired)	3	108	Steam	Coal/NG	1955	
	5	181	CCGT	NG	2002	
	6	228	CT	NG	2018	
Blue Lake	1	50	CT	NG/Oil	1974	16,670
	2	50	CT	NG/Oil	1974	
	3	46	CT	NG/Oil	1974	
	4	48	CT	NG/Oil	1974	
	7	174	CT	NG/Oil	2005	
	8	177	CT	NG/Oil	2005	
Granite City	1	18	CT	NG/Oil	1969	4,885
(All Units Retired)	2	18	CT	NG/Oil	1969	
	3	18	CT	NG/Oil	1969	
	4	18	CT	NG/Oil	1969	
Hennepin Island	1-5	13.9	Hydro	Water	1882	6,352
High Bridge	1	185	CCGT	NG/Oil	2008	16,983
	2	185	CCGT	NG/Oil	2008	
	3	236	Steam	(note 2)	2008	
Inver Hills	1	62	CT	NG/Oil	1972	11,777
	2	62	CT	NG/Oil	1972	
	3	62	CT	NG/Oil	1972	
	4	62	CT	NG/Oil	1972	
	5	61	CT	NG/Oil	1972	
	6	62	CT	NG/Oil	1972	

SUMMARY OF DISMANTLING COSTS
(continued)
(All costs are in thousands of 2019 dollars)

Station	Unit	MWe rating	Type	Fuel	In Service	Station Cost
Electric Generation Facilities -Fossil						
Key City	1	18	CT	NG/Oil	1970	4,530
(All Units Retired)	2	18	CT	NG/Oil	1970	
	3	18	CT	NG/Oil	1970	
	4	18	CT	NG/Oil	1970	
Minnesota Valley	1	10	Steam	Coal	1949	22,508
(All Units Retired)	2	10	Steam	Coal	1949	
	3	44	Steam	Coal	1953	
Red Wing	1	9	Steam	RDF	1949	15,549
	2	9	Steam	RDF	1949	
Riverside	7	160	Steam	(note 3)	1964	40,725
(Unit 8 Retired)	8	231	Steam	Coal	2009	
	9	171	CT	NG/Oil	2009	
	10	171	CT	NG/Oil	2009	
Sherburne County	1	680	Steam	Coal	1976	168,356
	2	682	Steam	Coal	1977	
	3	876	Steam	Coal	1987	
Wilmarth	1	9	Steam	RDF	1948	15,903
	2	9	Steam	RDF	1951	
Gas Production/Storage Facilities						
Maplewood					1957	5,113
Sibley					1953	4,589
Wescott					1972	11,242
Fleet Totals		**6,439**				**$472,396**

NOTES:
1 Unit 2 receives steam from Units 5 HRSG
2 Unit 3 receives steam from Units 1 and 2 HRSGs
3 Unit 7 receives steam from Units 9 and 10 HRSGs

SUMMARY OF DISMANTLING COSTS
Wind Farms (Complete Removal)
(All costs are in thousands of 2019 dollars)

Station	Units	MWe rating	Type	Wind Farm Cost
Electric Generation Facilities -WTG				
Blazing Star I	100	200	Wind Turbine Generator	34,766
Border Winds	75	148	Wind Turbine Generator	30,974
Courtenay	100	190	Wind Turbine Generator	36,313
Foxtail	75	150	Wind Turbine Generator	27,558
Grand Meadow	67	99	Wind Turbine Generator	25,036
Lake Benton II	44	99	Wind Turbine Generator	16,829
Nobles	134	197	Wind Turbine Generator	43,589
Pleasant Valley	100	196	Wind Turbine Generator	38,738
Fleet Totals		**1,279**		**$253,804**

SUMMARY OF DISMANTLING COSTS
Wind Farms (Removal to 48 inches below grade)
(All costs are in thousands of 2019 dollars)

Station	Units	MWe rating	Type	Wind Farm Cost
Electric Generation Facilities -WTG				
Blazing Star I	100	200	Wind Turbine Generator	28,362
Border Winds	75	148	Wind Turbine Generator	25,046
Courtenay	100	190	Wind Turbine Generator	29,087
Foxtail	75	150	Wind Turbine Generator	22,288
Grand Meadow	67	99	Wind Turbine Generator	21,697
Lake Benton II	44	99	Wind Turbine Generator	14,197
Nobles	134	197	Wind Turbine Generator	35,955
Pleasant Valley	100	196	Wind Turbine Generator	31,505
Fleet Totals		**1,279**		**$208,138**

1. INTRODUCTION

1.1 OBJECTIVE OF STUDY

The objective of this dismantling cost study prepared by TLG Services is to present an estimate of the costs to dismantle Xcel Energy's fossil-fueled and wind farm generating electrical generating facilities, plus their gas production and storage facilities, in Minnesota, South Dakota, and North Dakota. This study is not intended to be a dismantling plan for each of the stations, but a cost estimate prepared to support current financial planning for future dismantling.

1.2 FACILITY DESCRIPTIONS

<u>Electric Generation Facilities</u>

Allen S. King is a single unit coal fired generating facility with a cyclone-fired boiler. It has a generating capacity of 511 MWe while burning low sulfur Wyoming coal. The plant is located in Oak Park Heights, Minnesota, on the St. Croix River. The unit was installed in 1968. From 2004 to 2007 the unit was completely refurbished as part of an emissions reduction project.

Angus Anson is a three-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. Units 1 and 2 were placed in service in 1994. Unit 3 was placed in service in 2005. The station generating capacity is 386 megawatts. Unit 1, 2, and 3 are rated at 109, 109, and 168 MWe, respectively. The station is located in Sioux Falls, South Dakota adjacent to the decommissioned Pathfinder nuclear facility. The remaining Pathfinder facility features holds the non-nuclear remnants of the test nuclear power plant (minus the reactor) built in 1965.

Black Dog generating station is located on the Minnesota River just south of the Twin Cities. Unit 5, which is a natural gas fired combined cycle combustion gas turbine, replaced the original Unit 1 boiler and steam turbine. The exhaust heat from Unit 5 gas turbine generates steam in the HRSG and powers the original Unit 2 steam turbine that was installed in the 1950's. The Unit 2 boiler has been abandoned in place. The boiler chimney has been removed. Units 3 is abandoned in place and Unit 4 was mostly removed to make room for a new simple cycle combustion gas turbine, Unit 6. The Unit 4 primary precipitator, air heater, forced draft, induced draft and gas recirculation fans, deaerator and storage tank, and one feed-water heater remain in place. The coal yard facilities have been removed as well as the boiler chimneys.

Blue Lake is a six-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity is 545 megawatts. Units 1-4 are rated at 50 MWe, 50 MWe, 46 MWe, 48 MWe, respectively. Units 7 and 8 are rated at 174 MWe and 177 MWe. The station is located in Shakopee, Minnesota along the Minnesota River. Units 1-4 were placed in service in 1974. Units 7 and 8 were placed in service in 2005.

Granite City is a four-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity was 72 megawatts with each of the four units rated at 18 MWe. The station is located in St. Cloud, Minnesota. The units were installed in 1970. The station was retired from service in June 2019.

Hennepin Island is a hydroelectric power plant located on the Mississippi River in Minneapolis, MN, on the west side of Hennepin Island. The station consists of five turbine-generator sets, and has a combined generating capacity is 13.9 Mw. The plant was installed in 1882; it was last refurbished in 2010.

High Bridge is a three-unit facility consisting of two combined cycle combustion gas turbines and one steam turbine. The combustion turbines are each direct coupled to a 185 MWe electric generator. The exhaust gas of each combustion turbine is ducted through its own HRSG. The steam from the HRSG is piped to a 236 MWe steam turbine. The station has a net dependable capacity of 606 MWe. The station was placed in service in 2008. It is located in downtown St. Paul, Minnesota, on the Mississippi River.

Inver Hills is a six-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity is 371 megawatts. Units 1-4 and 6 are rated at 62 MWe each. Unit 5 is rated at 61 MWe. The station is located in Inver Grove Heights, Minnesota. The units were placed in service in 1972.

Key City was a four-unit simple cycle combustion gas turbine peaking facility, capable of firing on oil or natural gas. The station generating capacity was 72 megawatts with Units 1-4 at 18 MWe each. The station is located in Mankato, Minnesota. The units were installed in 1970, and retired in March of 2015.

Minnesota Valley is a three-unit facility abandoned in place. The station consists of two 10 MWe and one 44 MWe coal fired units. The station is located in Chippewa County, Granite Falls, Minnesota. The two 10 MWe units were installed in the late 1940's. The third unit was installed in 1953. The station was retired from service in 2013. All coal yard facilities have been removed.

Red Wing is a two-unit generating facility that burns processed municipal solid waste, referred to as refuse-derived fuel (RDF). The station employs a combination duct scrubber with a baghouse to effectively cut emissions from burning RDF. The scrubber treats flue gas with a water spray and dry lime. The baghouse traps particulate by forcing gas streams through large filter bags. The generating capacity of each unit is 9 MWe. The station is located in Red Wing, Minnesota. The units were installed in the early 1950's (coal fired units) and later modified to burn RDF.

Riverside is a three-unit facility consisting of two combined cycle combustion gas turbine generators (Units 9 and 10) and one steam turbine (refurbished Unit 7 steam turbine). The combustion turbines are each direct coupled to a 171 MWe electric generator. The exhaust gas of each combustion turbine is ducted through its own HRSG. The steam from the HRSG is piped to the Unit 7 160 MWe steam turbine. Abandoned in place, and included in this estimate, are the retired Units 6, 7 and 8 boilers, and the Unit 8 steam turbine with all its associated piping and system components. The three operational units went into service in 2009. The station is located northeast of Minneapolis on the Mississippi River.

Sherburne County is a three-unit 2,238 MWe coal-fired facility. The station is located in Becker, Minnesota, 45 miles northwest of the Twin Cities, on the Mississippi River. Units 1, 2 and 3 have a net dependable capacity of 680, 682, and 876 MWe each, respectively. The units were installed in 1976, 1977, and 1987.

Wilmarth is an electric generating facility that burns RDF. The station employs a combination duct scrubber with a baghouse to effectively cut emissions from burning RDF. The scrubber treats flue gas with a water spray and dry lime. The baghouse traps particulate by forcing gas streams through large filter bags. The generating capacity of Unit 1 and 2 is 9 MWe each. The station is located in Mankato, Minnesota. The units were installed in the early 1950's and modified in 1987 to burn RDF.

Gas Production/Storage Facilities

Maplewood is a propane storage facility with an effective propane storage capacity of 1.355 million gallons. The plant, located in Maplewood, Minnesota, was placed in-service in 1957.

Sibley is a propane storage facility used to supplement natural gas supplies during peak demand periods, with an effective propane storage capacity of 1.2

million gallons. The plant, located in Mendota Heights, Minnesota, was placed in service in 1953.

Wescott is a liquefied natural gas peak-shaving plant. The facility collects and stores natural gas for future supply to the local natural gas distribution systems during cold winter periods when regional natural gas supplies may not meet the increased demand. The facility is located in Inver Grove Heights, Minnesota, and was completed in 1972.

Wind Farms

Blazing Star I is a 100-unit wind turbine complex located on privately owned farmland in Lincoln County in southwestern Minnesota. The wind farm is composed of 10, 2.0 MWe V-110 and 90, 2.0 MWe V-120 Vestas wind turbines for a complex total of 200 MWe. The units are expected to be placed into full service in 2020.

Border Winds Project is a 75-unit wind turbine complex located on privately owned farmland in Rolla, North Dakota. The wind farm is composed of 75, 2.0 Mwe (nominal) V-100-2.0 Vestas wind turbines for a complex total of 148 MWe. The units were placed into service in 2015.

Courtenay is a 100-unit wind turbine complex located on privately owned farmland in Jamestown, North Dakota. The wind farm is composed of 100, 2.0 MWe (nominal) V-100-2.0 Vestas wind turbines for a complex total of 190 MWe. The units were placed into service in 2016.

Foxtail is a 75-unit wind turbine complex located on privately owned farmland in Kulm, North Dakota. The wind farm is composed of 7, 2.0 MWe V-110 and 68, 2.0 MWe V-120 Vestas wind turbines for a complex total of 150 MWe. The units were placed into service in 2019.

Grand Meadow is a 67-unit wind turbine complex located in a stretch of farm fields six miles long and four miles wide. The farm is spread out over roughly 10,000 acres southeast of Interstate 90 in Grand Meadow, Clayton, and Dexter Townships in Mower County, Minnesota. Each GE 1.5-77 wind turbine / generator set has a rated capacity of 1.5 Mwe (nominal) for a complex total of 99 MWe. The units were placed in service in 2008.

Lake Benton II is a 44-unit wind turbine complex located on privately owned farmland in Ruthton, Minnesota. The wind farm is composed of 5, 2.1 Mwe (nominal) GE 2.1-116 and 39, 2.3 Mwe (nominal) GE 2.3-116 General Electric wind turbines for a complex total of 99 MWe. The units were placed into service in 2019.

Nobles is a 134-unit wind turbine complex located in the Buffalo Ridge area of Minnesota. The wind farm is spread out over roughly 42 square miles in Nobles County, Minnesota, in Olney, Dewald, Larkin, and Summit Lake townships. Each GE 1.5-77 wind turbine / generator set has a rated capacity of 1.5 Mwe (nominal) for a complex total of 197 MWe. The units were placed in service in 2011.

Pleasant Valley is a 100-unit wind turbine complex located on privately owned farmland in Dexter, Minnesota. The wind farm is composed of 100, 2.0 (nominal) MWe V-100-2.0 Vestas wind turbines for a complex total of 196 MWe. The units were placed into service in 2015.

1.3 SCOPE

The scope of the dismantling estimate includes the following significant cost elements:

- Preparation for safe dismantling;
    - Hazardous materials characterization for such items as ACM (asbestos-containing materials), lead, mercury, PCBs, hydrocarbons in soil, etc.
    - Isolation of the units in preparation for safe dismantling (e.g. ensuring systems are de-energized, fuel and chemical storage tanks are drained and cleaned, etc. (where applicable)
- Abatement of ACM prior to dismantling (where applicable)
- Labor, equipment, and material costs associated with the removal and disposition of all installed equipment
- Labor, equipment, and material costs associated with the demolition and disposition of buildings and foundations
- Demolition contractor's on-site management, engineering, safety, and administrative staff
- Demolition contractor's expenses, including insurance, permits, and fees.
- Xcel's on-site management, oversight, and security staff
- A cost credit associated with the disposition of scrap metals
- Cost contingency

Costs are provided for each generating station or facility, identified by significant cost element. The cost per station includes the costs for dismantling the generating unit and the common station facilities. Costs are provided in 2019 dollars.

1.4 GENERAL APPROACH

The general approach in assembling the estimate was to develop an inventory of equipment and structures designated to be removed for each facility. This inventory was established using site walk-downs (including discussions with the Operations & Maintenance staff), station-provided equipment databases, and plant drawings. This inventory accounted for similarities between facilities.

The abatement, removal, demolition and restoration activity costs are estimated by applying unit cost factors (developed for each inventory item) against the inventory. Costs for project management, shared equipment and consumables, and similar types of costs are estimated on a period-dependent basis (i.e., the magnitude of the expense depends, in part, on the duration of the project and the types of activities taking place). The potential value of scrap from materials generated in dismantling the plant components and building structural steel is included as a credit in the dismantling cost estimate. Contingency is provided within this estimate to account for unpredictable project events.

OSHA states that demolition involves additional hazards due to unknown factors which make demolition work particularly dangerous. OSHA further states that the hazards of demolition work can be controlled and eliminated with the proper planning, the right personal protective equipment, necessary training, and compliance with OSHA standards. The cost estimate is intended to provide sufficient monies to allow Xcel management to perform the project using these principles and standards.

Limited site landscaping is included, which covers grading and seeding for drainage and erosion control.

Section 2 of this report identifies the activities and sequence of activities necessary to dismantle a generating station. Section 3 provides the specific bases for the estimate. Section 4 discusses scrap metal and associated credits to the dismantling costs. Section 5 provides the results. Appendices, noted throughout this report, provide additional information important to understanding this estimate.

2. DISMANTLING OPERATIONS

The estimate for dismantling the stations is based on the complete removal of the units and common station facilities (except where noted). The following sections describe the project organization, basic activities, and special equipment necessary for accomplishing the dismantling project.

The actual dismantling program begins once the station owner has decided to dismantle the site, either immediately following final shutdown, or after a period of storage following final shutdown. The dismantling program has been organized into three distinct periods: Period 1 - Engineering/Planning and Asbestos and Other Hazardous Material Abatement (if necessary); Period 2 - Dismantling Operations; and Period 3 - Site Restoration. This section summarizes the activities performed under each Period of the program.

For the purposes of this estimate it is assumed that once the decision to dismantle has been made and a project start date established, the work in each of these periods will be completed successively (no delay between periods). This report does not attempt to describe all of the activities necessary to dismantle a station, but identifies representative activities appropriate to this type of project.

2.1 PRE-SHUTDOWN ACTIVITIES

The estimates include a planning staff for a year prior to final shutdown to plan for the dismantling program. A staff of seven full-time equivalent personnel is included in this estimate; smaller stations will have a reduced staffing amount.

2.2 POST-SHUTDOWN PLANT STAFF TRANSITION ACTIVITIES

The estimate is based on each station being shut down and placed into a post-shutdown configuration by the plant staff. The length of time that the facility is in this configuration is indeterminate and the costs for maintaining the facility in this configuration is not included within the scope of this dismantling effort. The activities to be completed post-shutdown, but prior to station dismantling, include:

- Removal of consumables and supplies not needed in the post-shutdown configuration
- Removal of residual fuels (including oil/coal)
- Removal of acids and caustics; flushing and cleaning of storage tanks

- Disposition of surplus bulk chemicals and gas storage containers
- Removal of miscellaneous hazardous wastes and combustible materials
- Installation of any appropriate physical barriers (sealing circulating water system) and/or security barriers

The estimate does not account for an extended period of time between final shutdown of the unit(s) and onset of the dismantling program. As such, the plant operations and maintenance staff would be expected to perform the following activities in the interval of time between final plant shutdown, and the onset of the dismantling program.

- If the unit is to be maintained in a condition where lighting, electricity, heating, water, sanitary, and similar services are to remain active, reconfigure these systems to minimize maintenance requirements
- Maintenance of the facility (maintaining roofs and windows, drain systems, and electrical systems to preclude creating hazardous working conditions in the future)

2.3 DISMANTLING ENGINEERING / PLANNING AND ASBESTOS ABATEMENT

When the decision is made to begin physical dismantling of a station, Xcel Energy will begin field dismantling activities, beginning with engineering and planning, and removal of asbestos and other hazardous materials from the station.

2.3.1 Engineering and Planning

A preliminary planning phase of the program begins once it is has been determined that a station will be dismantled and the project has been authorized to proceed. During this phase, the owner assembles its dismantling management organization, makes appropriate decisions regarding the extent of dismantling and the approach to managing the activities, and accomplishes those site preparation activities necessary to transition from a plant shutdown configuration to site dismantling. For purposes of this estimate it is assumed that the intent is to dismantle the entire station as a single project. Costs incurred during this preliminary phase of the program are included in the dismantling costs presented in this study.

Xcel Energy prepares the stations for dismantling by performing the following activities:

- Prepare specifications that identify and describe the objectives and major work activities to be accomplished (establishing the final site configuration)
- Assemble plant documentation that may be relevant to dismantling (drawings, hazardous material reports, environmental studies, etc.)
- Select an asbestos abatement contractor (if required) and Dismantling Contractor
- Assemble and mobilize the management and oversight team responsible for the project
- Documenting hazardous materials location and inventory

2.3.2 Asbestos / Hazardous Material Abatement (as applicable)

The asbestos abatement contractor prepares for this work by thoroughly understanding the scope of the asbestos remediation work and obtaining the permits necessary to initiate the work. Abatement of asbestos is considered an important prerequisite to dismantling the station's systems and structures. The method by which asbestos is abated is strictly controlled by federal and/or state regulations and includes the following requirements:

- Work will be done inside enclosures designed to capture any asbestos-containing particles. With the exception of removal of small quantities of asbestos in local areas, it would be expected that most work will be done in large enclosures (containment tents). The enclosures will have a filtered exhaust and be maintained under negative air pressure (air will leak into the enclosure rather than leak out).
- The air outside of the enclosures will be monitored to ensure barriers are effective.
- Workers, while working inside enclosures, will wear respiratory protective equipment as well as protective clothing.
- All materials removed from the enclosure will be packaged in accordance with regulations (minimum double-bag), and will be removed via a materials handling access area.
- Workers will enter and exit the enclosures through a personnel decontamination chamber in a controlled manner (ensuring asbestos contamination does not spread beyond the containment).

- After the asbestos abatement is complete, the effectiveness of the process will be established via regulatory-specified processes (generally verifying that there is no asbestos containing material capable of becoming airborne).
- Asbestos containing materials will be disposed of at a properly licensed disposal facility.
- After ensuring that all asbestos has been removed, the enclosures will be taken down in accordance with regulatory requirements and disposed of at a licensed facility.
- Clean coal-fired boilers by washing down all surfaces interior to the boilers.
- Clean fly-ash handling equipment, e.g., filters and holding tanks.
- De-water ash settling ponds and/or basins.

2.3.3 Dismantling Preparations

The dismantling contractor prepares the station for dismantling by performing the following activities:

- Installing environmental barriers and monitoring equipment
- Reviewing plant drawings and specifications that may be useful for the dismantling project
- Identifying the processes to achieve the final desired station configuration
- Identifying the major work sequence
- Preparing dismantling activity specifications and work orders/forms
- Preparing detailed dismantling procedures
- Preparing a dismantling plan
- Preparing permit application(s) for plant demolition
- Mobilizing site staff
- Configuring temporary services/facilities to support dismantling operations
- Arranging for heavy lift and dismantling equipment, rigging, and tooling
- Hiring and training the labor force

2.4 DISMANTLING OPERATIONS

Dismantling activities are initiated after completing the engineering and planning process, and after asbestos abatement and removal of hazardous materials is complete. The sequence of activities will be determined at the time of dismantling, but typically a sequence would include the following items. Dismantling sequences are presented for each of the Xcel Energy facility types. In all types the station is electrically disconnected from all power sources; the Dismantling Contractor will provide temporary power as needed to support the removal activities.

2.4.1 Steam Plants

- Removing coal yard equipment (if required), including unloading structures, conveyors, transfer towers, and reclaim systems
- Removing above-ground storage tanks
- Removing large equipment from rooftops or at higher elevations
- Removing equipment that must be removed prior to start of boiler structure removal, including fly-ash handling, coal handling, burner fuel supply, scrubbers, air and flue gas ducts, etc.
- Removing electrostatic precipitator and bag houses by cutting casings and connecting gas ducts
- Removing the top of the boiler enclosure to allow access to the platens
- Removing the boiler waterwalls
- Removing steam drum and deaerator by severing all connections and lowering to grade
- Removing boiler structural steel
- Disassembling the turbine/generator and condenser
- Removing all other equipment and components required prior to structures demolition
- Removing the turbine building superstructure and interior floors
- Blasting/dismantling the concrete turbine-generator pedestal(s)
- Removing siding from buildings
- Dismantling steel framing
- Demolishing structural concrete

- Removing the stack(s)
- Removing cooling tower(s) and / or cooling water intake and discharge structures
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to remove reinforcing steel
- Removing any temporary services used to support the dismantling effort (lighting / ventilation / electrical / groundwater management)

2.4.2 Combustion Turbines

- Removing above-ground storage tanks
- Removing large equipment from rooftops or at higher elevations
- Disassembling the turbine and generator
- Removing all other equipment and components required prior to building demolition
- Blasting/dismantling the concrete turbine-generator foundation(s)
- Demolishing remaining concrete
- Removing cooling tower(s) and / or cooling water intake and discharge structures (High Bridge only)
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to remove reinforcing steel

2.4.3 Hydroelectric Plants

- Installing cofferdams at inlet to power channel and discharge channel
- Removing large equipment from rooftops or at higher elevations
- Disassembling and removing the generators
- Disassembling and removing the water turbines
- Removing all other equipment and components required prior to structures demolition

- Removing the powerhouse structure and interior floors
- Blasting/dismantling the concrete turbine-generator foundations
- Dismantling steel framing
- Demolishing brick walls and structural concrete
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to remove reinforcing steel

2.4.4 Wind Turbines (complete removal)

- Removing turbine blades from turbine shaft
- Removing turbine-generator housings from towers
- Removing towers from foundations
- Removing all other equipment and components required prior to structures demolition
- Blasting/dismantling the concrete tower foundations
- Excavating and removing all buried electrical cables
- Removing all other site structures within the scope of the dismantling program
- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to enhance its suitability for backfill

2.4.5 Wind Turbines (removal to 48" below grade)

- Removing turbine blades from turbine shaft
- Removing turbine-generator housings from towers
- Removing towers from foundations
- Removing all other equipment and components required prior to structures demolition
- Removing the concrete tower foundation pedestal to 48" below grade
- Buried electrical cables below 48" left in place
- Removing all other site structures within the scope of the dismantling program

- Sorting and organizing materials for pickup by the scrap dealer(s)
- Size reducing concrete rubble to enhance its suitability for backfill

2.5 SITE RESTORATION

Site restoration activities are initiated following completion of the dismantling operations. The objective of site restoration in this estimate is to restore the station grounds to a configuration that does not pose a safety hazard; and plant vegetation for erosion control. As such, landscaping will be limited to grading, placement of top soil, and seeding. Site restoration as used in this estimate is not intended to re-configure the station for redevelopment, e.g. use as a recreational or industrial facility.

A typical site restoration sequence would be:

- Crush all concrete rubble and remove reinforcing steel. Concrete debris will be shipped off site for disposal as construction debris. Reinforcing steel will be recycled
- Backfill below grade voids with clean compactible fill as necessary.
- General grading of the station
- Placement of top soil or other suitable surface material necessary to maintain erosion control
- Landscaping to the extent necessary to re-vegetate the station (grass or similar plant materials), and
- Demobilizing personnel and equipment

3. COST ESTIMATE

The basis, methodology, and assumptions for the site-specific cost estimate are described in the following paragraphs.

3.1 BASIS OF ESTIMATE

Inventory of Materials to be Removed

The inventory is an essential element of the estimate, since dismantling costs are determined by applying unit cost factors against the corresponding inventory quantities. For each of these estimates a site-specific inventory of materials to be removed was developed using a combination of methods. The inventory used in developing the estimate for each station is provided in Appendix A.

Comparable Boiler / Turbine Unit Information Available to TLG Where TLG had previously developed inventory information for a boiler and turbine of similar size, fuel type and vintage, referred to as "reference unit", this information was used to represent the boiler / turbine systems inventory for the comparable Xcel Energy unit. In the same manner, non-steam power facilities were also used as reference units for other, similar Xcel Energy facilities. The inventory was adjusted to reflect the difference between the rating of the Xcel Energy reference unit and the rating of the comparable unit.

There are expected differences in other facilities, even if the power generating equipment are similar between comparable units. These include systems and structures associated with cooling water intake and discharge, fuel handling, exhaust gas, maintenance buildings and shops, pollution-control, and the quantity and extent of asbestos containing material (if applicable). For these systems and structures TLG developed the inventory by conducting a walk-down of the station, and extracting information from station-specific drawings and photos.

Comparable Plant Information Not Available to TLG Where the Xcel Energy unit(s) had no comparable match in the TLG database, the site specific inventory was developed "from scratch", by completing a physical walk-down of each such unit, discussions with the stations' Operations & Maintenance staff, and extracting data from station-specific maintenance databases (lists of equipment), drawings, and photos.

Economic Cost Drivers (Reference in Section 6)

In developing an estimate, the cost of labor, equipment and material, credit for scrap, and similar costs will influence the results of the estimate. The basis for the significant cost drivers are:

1. Craft labor rates are based on existing contracts with craft labor contractors. These rates were provided by Xcel Energy (Ref. 1).
2. Utility labor rates are based on labor costs for positions likely to be employed during the dismantling project. The 2014 rates were escalated to 2019 values, per Xcel Energy approval, using U.S. Department of Labor's Bureau of Labor Statistics, Consumer Price Index Series ID:CUUR0000SAS (Ref. 2).
3. Material and equipment costs for conventional demolition and/or construction activities, Contractors Insurance, Small Tools Allowance, Permit / Fees, and Contractor's Fee are based on R.S. Means Construction Cost Data (Ref. 3).
4. Scrap metal prices are based on a five-year average of published indices (Ref. 4).
5. Contingency, contractor fee, contractor insurance, environmental sampling, and permits & fees are based upon R.S. Means Construction Cost Data.
6. Costs in this estimate are in 2019 dollars.
7. Property taxes (or payments in lieu of taxes) are not included within the estimate.
8. The estimate to dismantle the stations does not address credit associated with the residual value of the land.

Project Organization

For the purposes of this study, the dismantling project for each station is assumed to be managed by Xcel Energy's Project Director, who would have the primary responsibility for dismantling the station. A Dismantling Contractor, experienced in dismantling similar facilities, would be hired as the prime contractor for the removal of plant components and site facilities. The Dismantling Contractor's Project Manager would report to the Project Director. The Dismantling Contractor would manage and supervise the dismantling activities of the station and be responsible for completing the work in an expeditious and safe manner. Contractor personnel would manage and direct the labor force in accordance with approved procedures and in accordance with a health and safety program. The Xcel staff would maintain and/or provide the engineering, safety, and environmental compliance oversight, and the security services necessary to support dismantling operations. Figures 3.1 and 3.2 identify typical organizations for the plant/utility staff and the associated contractor personnel during the dismantling phase of the project. The smaller facilities included within this estimate would have a commensurately smaller project organization e.g. Angus Anson, Blue Lake, and Grand Meadow.

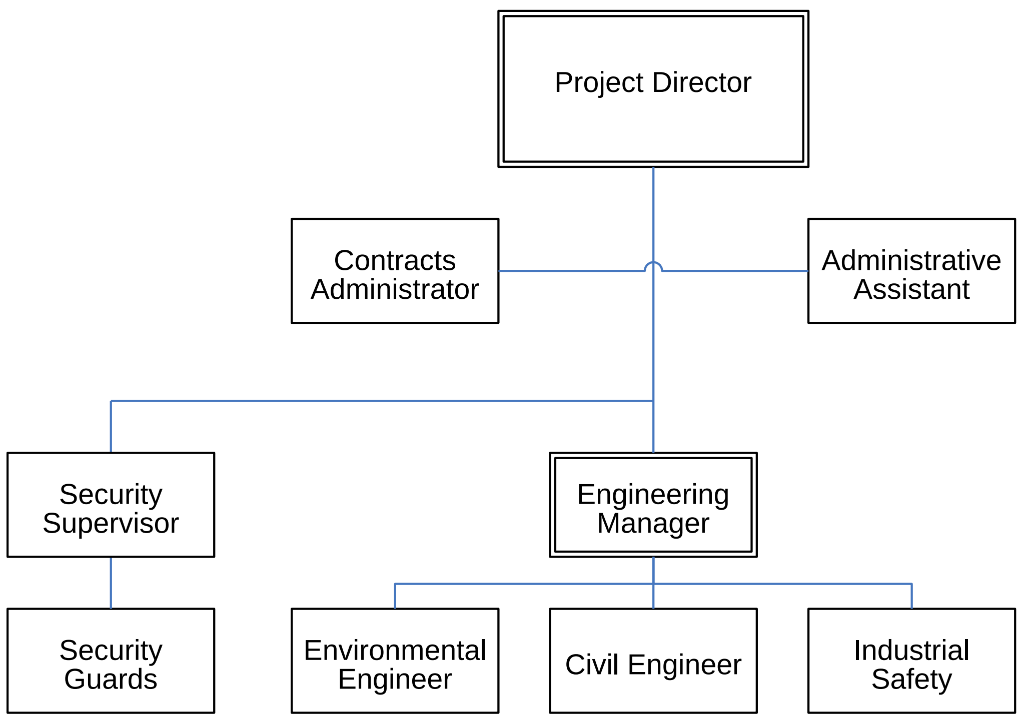
3.2 METHODOLOGY

The methodology used to develop the cost estimate follows the basic approach presented in the AIF/NESP-036, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates" (Ref. 5) and the US DOE "Decommissioning Handbook" (Ref. 6). These publications utilize a unit cost factor method for estimating decommissioning activity costs to simplify the estimating calculations. Unit cost factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/in) are developed from the labor cost information from R. S. Means. The activity-dependent costs are estimated using item quantities (cubic yards, tons, inches, etc.) developed from plant drawings and inventory documents. The unit factors used in this study reflect the latest available information on worker productivity in plant dismantling. A sample unit cost factor is provided in Appendix B. A list of unit cost factors is provided in Appendix C.

An activity duration critical path is developed to determine the total dismantling program schedule. This program schedule is then used to determine the period-dependent costs for program management, administration, field engineering, equipment rental, quality assurance, and security. TLG escalated 2014 Xcel Energy salary and hourly rates for personnel associated with period-dependent costs. The costs for conventional demolition of structures, materials, backfill, landscaping, and equipment rental are obtained from R.S. Means. Examples of such unit cost factor development are presented in AIF/NESP-036.

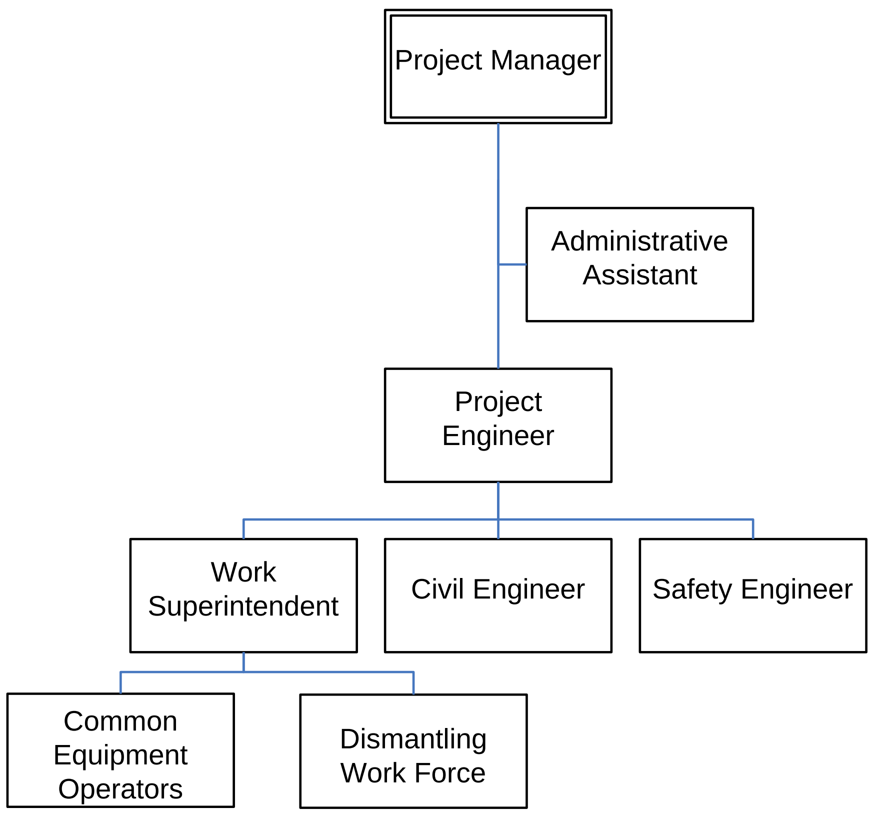
The unit cost factor method provides a demonstrable basis for establishing reliable cost estimates. The detail of activities for labor costs, equipment and consumables costs provide assurance that cost elements have not been omitted. Detailed unit cost factors, coupled with the site-specific inventory of piping, components and structures provide confidence in the cost estimates.

FIGURE 3.1
DISMANTLING PROJECT ORGANIZATION
UTILITY STAFF



For a large station such as Sherburne County, this represents a full-time equivalent staffing level of six personnel. This value is reduced for smaller stations.

FIGURE 3.2
DISMANTLING PROJECT ORGANIZATION
DECOMMISSIONING CONTRACTOR STAFF



For a large station such as Sherburne County, this represents a full-time equivalent staffing level of 11.5 personnel. This value is reduced for smaller stations.

The activity-dependent and period-dependent costs are combined with applicable collateral costs to yield the direct decommissioning cost. A contingency is then applied. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook" (Ref. 7) as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this estimate are based on ideal conditions; therefore, a contingency factor has been applied.

Examples of items that could occur but have not otherwise been accounted for in this estimate include: labor work stoppages, bad weather delays, equipment/tool breakage, changes in the anticipated plant shutdown conditions, etc. These types of unforeseeable events are discussed in the AIF/NESP-036 study. Guidelines are also provided for applying contingency.

3.3 ASSUMPTIONS

The following assumptions were used in developing the dismantling estimate.

Pre-requisite Activities

1. Dismantling of the station will not commence until all units are retired (cost estimate is not based on independent dismantling of units while adjacent units are operating).
2. The arrangements of the unit facilities as they exist in 2019 based upon walk-downs conducted by TLG, and databases and drawings provided by owner.
3. The dismantling process will be an engineered process with substantial consideration for occupational (worker) safety.
4. The demolition will be performed by a Dismantling Contractor who is responsible to provide adequate staff and equipment to complete the dismantling in a safe manner.
5. Site security costs to restrict access to the demolition project by unauthorized personnel are included.
6. The estimates are based on industrial safety and environmental regulations effective in 2019.
7. All power to the structures will be disconnected prior to beginning removal activities ("Cold and Dark"). The Decommissioning Contractor will provide for temporary power as needed to support dismantling activities.

8. End of life water inventory management in regulated ponds will be addressed in accordance with federal and state rules and closed in place after shutdown.
9. On-site fuel inventories will be used and/or removed prior to start of dismantling.
10. Silos, precipitators, hoppers, tanks, etc., will be emptied by operations and maintenance staff after shutdown.
11. Acids, caustics, and similar hazardous materials will be removed by operations and maintenance staff after shutdown.
12. Consumables, such as ion exchange materials and filters, will also be removed by operations and maintenance staff after shutdown.
13. Stores, spare parts, gas storage containers, laboratory equipment, office furniture, etc., will be removed by the owner after shutdown.
14. Oils used in station transformers may contain PCBs. Lubricating and transformer oils are drained and removed by operations and maintenance staff after shutdown. If any PCB contaminated oil is encountered, it will be removed and disposed of properly.
15. Asbestos (if present) will be removed prior to the start of dismantling. Asbestos insulation and PACM (presumed asbestos containing materials) will be disposed of at licensed facilities. Quantities of asbestos are based on owner-provided information where available. Where such information was not available, the quantities of asbestos were estimated.
16. Prior to initiating dismantling, essentially all live circuits will have been de-energized (to preclude creating an industrial hazard). If required, temporary services systems (air, water, electrical, fire water, etc.) will be used to support dismantling operations and will remain in service throughout the project until no longer required.

<u>Economic Assumptions</u>

17. Post-shutdown "dormancy" costs (i.e., security and maintenance on any of the units retired prematurely) are not included in the study.
18. Escalation/inflation of the costs over the remaining operating life is not included.
19. An allowance of 2% of craft labor costs is used for small tools.
20. A 12.5% fee is added to the Demolition Contractor's cost to account for its overhead and profit.
21. A 25% contingency is applied to asbestos remediation activities.

22. A 15% contingency is applied to all remaining dismantling-related costs.
23. A credit for scrap metal cost recovery is included in the estimates. Retired plant equipment is assumed to have no value as salvage (sold for re-use).

Physical Work Assumptions

24. The costs for disposition (if required) of contaminated soil (e.g., PCBs, hydrocarbons, lead, asbestos, mercury, acids or caustics) are outside the scope of this estimate.
25. Large equipment and components will be removed prior to structures demolition.
26. An environmental hazards crew will be maintained throughout the demolition period to address such items as lead paint and asbestos that was inaccessible during the asbestos remediation period (where applicable).
27. Turbine pedestals and powerhouse building foundations will be removed by demolition equipment and back-filled to grade.
28. Structures and foundations will be removed with any resulting voids back-filled to grade level. An additional scenario is provided for the wind farms where the equipment and structures are removed only to a depth of 48 inches.
29. Chimney stacks will be blasted to the ground and broken into rubble, the steel liners cut and removed, and the foundations removed.
30. The dismantling of the electrical equipment terminates at the switch yard boundary. The switch yard is left intact.
31. Concrete rubble generated during dismantling will be crushed, reinforcing steel removed, and the concrete disposed of offsite as construction debris.
32. The site will be graded; however, no effort was included in this estimate to restore the original contour of the land. Ground cover will be established for erosion control.
33. Roads, parking lots, etc., are removed after the facility is dismantled (with the exception of the immediate area around the switchyard).

Scheduling Assumptions

34. All work is performed during an eight-hour workday, five days per week, with no overtime.
35. Multiple crews work parallel activities to the maximum extent possible, consistent with efficiency (adequate access for cutting, removal, and

laydown space) and with industrial safety appropriate for demolition of heavy components and structures.

36. Scheduling was calculated without constraints on availability of labor, equipment, or materials.

3.4 STATION-SPECIFIC NOTES

3.4.1 Allen S. King

- All currently operational coal handling equipment and the abandoned-in-place coal barge unloader facility with the twenty-two dolphin-type barge piers are included in the estimate.
- A cofferdam will be installed to allow removal of the condenser cooling water discharge structure and the discharge structure from the cooling tower.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- The soil beneath the area of the coal pile will be removed to a depth of five feet; the soil will be disposed of offsite as solid waste.
- The ash pond will be backfilled with clean fill prior to placement of the closure cap.

3.4.2 Angus Anson

- The Pathfinder Unit 1 building has been included in this estimate.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Concrete will only be removed to three feet below grade.
- Two large oil storage tanks are included in the estimate. One tank is currently in service. The other tank has been cleaned and remains on stand-by.

3.4.3 Black Dog

- The abandoned-in-place Unit 2 boiler is included in the estimate.
- All chimneys from the coal burning operation have been removed.
- All operational coal handling equipment external to the building e.g. conveyors, rail car unloader, transfer towers, stacker conveyor etc. have been removed. Coal conveyors inside the plant have been abandoned in place but not yet removed.
- A cofferdam will be installed to remove the intake condenser cooling water structure.

3.4.4 Blue Lake

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Two large oil storage tanks are included in the estimate. One tank is currently in service. The other tank has been cleaned and remains on stand-by.

3.4.5 Granite City

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Two large oil storage tanks are included in the estimate. The tanks have been cleaned.

3.4.6 Hennepin Island

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- The estimate does not include dam or earthworks removal, or ongoing maintenance.
- Inlet channel to turbines will be backfilled.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.

3.4.7 High Bridge

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

- A cofferdam will be installed to remove the river intake and discharge structure.

3.4.8 Inver Hills

- Gas supply lines will be cut and capped at the source.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.9 Key City

- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- Two large oil storage tanks are included in the estimate. The tanks have been cleaned.

3.4.10 Maplewood Gas Plant

- Facility includes multiple liquefied natural gas storage tanks.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.11 Minnesota Valley

- All three of the abandoned in-place units are included in the estimate.
- The asbestos quantities were calculated considering Unit 3 to be all asbestos and Units 1 and 2 to only have small amounts on the partially dismantled boilers.
- A cofferdam will be installed to remove the river intake and discharge structure.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- All coal yard facilities have been removed and the ash ponds have been closed.

3.4.12 Red Wing

- The RDF unloading facility and the conveyor transport system are included in the estimate.
- A cofferdam will be installed to remove the cooling water intake and discharge structure.
- The barge unloading facility in not included in the estimate.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- The ash landfills will be closed in place by capping with a synthetic liner, placing cover over the cap, and seeding.

3.4.13 Riverside

- Included in this estimate are the following abandoned-in-place facilities and equipment:
    - Unit 6, 7 and 8 building structure
    - Unit 6 and 7 boilers
    - Unit 8 boiler, turbine and associated equipment
- Cofferdams will be installed to remove the four cooling water intake and discharge structures.
- Includes barge unloading dock and concrete piles.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).

3.4.14 Sherburne County

- All coal handling facilities e.g. coal barn, rail car dumper building, coal yard control and maintenance facility, earthen storage berms, conveyor systems, transfer towers etc. are included in this estimate.
- All warehouse/storage type buildings on the site are included in the estimate.
- A cofferdam will be installed to remove the cooling water intake and discharge structure.

- The boiler and precipitator/baghouse will be cleaned prior to dismantling.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM) – Units 1 and 2 only.
- The soil beneath the area of the coal pile will be removed to a depth of five feet; the soil will be disposed of on site in the ash pond.
- The ash pond will be backfilled with coal yard soil prior to placement of the closure cap.
- The Unit 3 dry ash landfill will be closed and capped in accordance with Minnesota's solid waste permit requirements and applicable federal coal combustion residual rules.
- Some of the planning for Sherburne County includes a unit shutdown with the other units remaining in operation for a number of years. In this event, the costs in Table 5.1n, for the shutdown unit only, should be increased by some fraction to allow for constraints on demolition activities on the shutdown with the other units operational. Based upon discussions with Xcel Energy personnel, an increase of 20% can be used for planning purposes.
- The ash landfills will be closed in place by capping with a synthetic liner, placing cover over the cap, and seeding.
- Two large settling tanks are included in the estimate.

3.4.15 Sibley Gas Plant

- Facility includes multiple liquefied natural gas storage tanks.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.16 Wescott Gas Plant

- Facility includes two large insulated liquefied natural gas storage tanks.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.17 Wilmarth

- The RDF bulk storage facility is not included in the estimate. Only the transport section of the facility with conveyor systems and transfer towers is included.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.
- The boiler and precipitator will be cleaned prior to dismantling.
- Lead paint on concrete surfaces will be removed prior to demolition of the concrete structures.
- Rockbestos-insulated electrical cabling and other ACM in cable trays will be removed (all cable trays & cabling disposed of as ACM).
- The ash landfills will be closed in place by capping with a synthetic liner, placing cover over the cap, and seeding.

3.4.18 Wind Farms – Blazing Star I, Border Winds, Courtenay, Foxtail, Grand Meadow, Lake Benton II, Nobles, Pleasant Valley

- All underground power and control cables will be excavated and removed.
- Tower foundations are completely removed.
- All access roads surfaces will be excavated and removed. The excavated areas will be back-filled with soil.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

3.4.19 Wind Farms (Removal to 48-inch depth) – Blazing Star I, Border Winds, Courtenay, Foxtail, Grand Meadow, Lake Benton II, Nobles, Pleasant Valley

- All underground power and control cables will be excavated and removed to a depth of 48 inches below grade.
- Tower foundations pedestals will be removed to 48 inches below grade.
- All access roads surfaces will be excavated and removed. The excavated areas will be back-filled with soil.
- There is a reduced decommissioning management and contractor staff due to the smaller size of this facility.

4. SCRAP METAL CREDITS

The dismantling of a typical fossil plant occurs after a lengthy plant operating life. The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. Xcel Energy will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that buyers prefer equipment stripped down to very specific requirements before they would consider purchase. This can require expensive work to remove the equipment from its installed location, which is inconsistent with the rapid dismantling approach assumed in this estimate. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall cost of dismantling, this analysis does not attempt to quantify the value that an owner may realize based upon those efforts.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property is removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts are made available for alternative use.

The materials used in the equipment and buildings are suitable for recycle as scrap metals. As such, an estimated value of the scrap metal credit has been developed and applied to each station's cost estimate. The value of scrap was estimated using a five-year average of market values extracted from published sources and applying this value to the estimated quantities of materials generated from the dismantling project. There were four basic types of metals used in the scrap estimates; carbon steel (the most common material used at the station), copper, stainless steel (high alloy steel) and aluminum. The scrap credit, in addition to considering the quantity and types of materials, also considered the cost of handling and transporting these materials to a major scrap processing location in the Twin Cities area where scrap is used or sold. The value of the scrap is reduced by the transportation costs.

The basis for scrap metal value is summarized in Table 4.1. A summary of the basis for the scrap credit is provided in Tables 4.2 which details the scrap quantities by material type from each unit, and Table 4.3 lists the dollar value of these quantities.

TABLE 4.1a
BASIS FOR SCRAP METAL VALUE
(2019 dollars)

Fossil Stations

Type of Material	Scrap Category [1]	Market Value [2]	Units	Transport Cost [3]	Scrap Metal Credit [4] (per ton)
Carbon Steel	Cast Iron	202.40	Per Ton	46.85	155.56
	No. 1	253.01	Per Ton	46.85	206.16
	Mixed Scrap	202.40	Per Ton	46.85	155.56
	Galvanized	55.66	Per Ton	46.85	8.81
Stainless Steel	SS-1	0.77	Per Pound	0.02	1,490.20
Copper	Insulated Cable	1.32	Per Pound	0.02	2,586.11
	No. 2 Copper	2.11	Per Pound	0.02	4,168.50
	Copper-Nickel	3.20	Per Pound	0.02	6,355.94
	Large Motor	0.32	Per Pound	0.02	585.41
Non-Ferrous	Aluminum	0.29	Per Pound	0.02	532.27

Note 1: Scrap categories are consistent with information provided in Recycler's World.

Note 2: The market value for scrap metal used in this estimate is based on Recycler's World U.S. Scrap Metal Index Spot Market Prices. Values shown represent the average over a 5-year period from January 1, 2015 to December 31, 2019 (See Section 6, reference 4).

Note 3: The estimated cost for handling and transporting the materials to a major scrap processing center in the Twin Cities area is $46.85 / ton or $0.023 / pound.

Note 4: The scrap metal credit reflects the market value of scrap adjusted for handling and transport cost to local scrap metal recycler.

TABLE 4.1b
BASIS FOR SCRAP METAL VALUE
(2019 dollars)

Wind Farms

Type of Material	Scrap Category [1]	Market Value [2]	Units	Scrap Metal Credit [3] (per ton)
Carbon Steel	Cast Iron	202.40	Per Ton	202.40
	No. 1	253.01	Per Ton	253.01
	Mixed Scrap	202.40	Per Ton	202.40
	Galvanized	55.66	Per Ton	55.66
Stainless Steel	SS-1	0.77	Per Pound	1,537.05
Copper	Insulated Cable	1.32	Per Pound	2,632.95
	No. 2 Copper	2.11	Per Pound	4,215.35
	Copper-Nickel	3.20	Per Pound	6,402.79
	Large Motor	0.32	Per Pound	632.26
Non-Ferrous	Aluminum	0.29	Per Pound	579.12

Note 1: Scrap categories are consistent with information provided in Recycler's World.

Note 2: The market value for scrap metal used in this estimate is based on Recycler's World U.S. Scrap Metal Index Spot Market Prices. Values shown represent the average over a 5-year period from January 1, 2015 to December 31, 2019 (See Section 6, Reference 4).

Note 3: The scrap metal credit reflects the market value of scrap cost to local scrap metal recycler. Scrap from the wind farms does not include transportation costs; the transport of the scrap from wind farms is separately accounted for in the cost tables *within "Item 1b. Haul Off of Materials (Trucking / Rail)."*.

TABLE 4.2a
QUANTITY OF SCRAP METALS BY STATION
(pounds)

Fossil Stations

	Carbon Steel			Stainless Steel	Galvanized	Copper			Copper		
Station Name	Cast Iron	No. 1	Mixed Scrap	SS-1	Steel	Insul Cbl	No. 2 Cu	Large Mtr	Nickel	Aluminum	Total
Allen S . King	2,976,846	41,253,822	53,751,220	231,075	1,010,675	157,197	590,394	1,816,821	515,763	-	102,303,814
Angus Anson	944,532	7,869,287	10,367,485	366,129	262,382	62,845	555,614	235,889	90,000	-	20,754,163
Black Dog	1,643,294	27,421,437	35,094,140	770,520	691,748	203,840	500,072	1,777,520	221,615	-	68,324,186
Blue Lake	562,895	7,151,454	16,794,779	471,749	151,311	66,137	534,704	167,052	-	-	25,900,081
Granite City	415,622	1,347,785	3,827,752	14,999	123,454	19,672	117,956	37,557	-	-	5,904,796
Hennepin Island	-	696,327	1,821,010	1,204	32,320	17,700	44,413	-	-	-	2,612,973
High Bridge	844,602	11,853,600	18,671,353	312,326	572,357	113,539	661,690	1,016,734	-	-	34,046,202
Inver Hills	203,824	4,050,420	12,115,948	911,580	66,005	-	537,241	6,408	-	-	17,891,426
Key City	415,622	1,000,333	3,795,209	14,999	123,454	19,672	107,108	37,557	-	-	5,513,953
Maplewood	55,689	2,277,558	514,983	109,319	31,504	6,904	16,564	374	-	-	3,012,895
Minnesota Valley	638,559	12,944,074	20,225,105	554,769	397,131	68,843	241,236	1,395,489	294,202	-	36,759,408
Red Wing	269,371	5,792,041	7,537,990	459,747	242,290	29,016	21,797	235,896	34,301	-	14,622,450
Riverside	717,166	26,334,947	48,412,618	275,384	437,669	61,010	596,359	1,432,370	-	-	78,267,523
Sherburne County	4,008,245	133,744,558	185,765,812	2,132,542	3,718,089	836,673	893,799	5,411,303	-	103	336,511,124
Sibley	53,710	1,828,422	373,174	103,107	43,503	6,703	13,829	7,250	-	-	2,429,699
Wescott	47,236	7,963,162	1,606,330	189,165	68,387	33,887	16,236	2,591	-	1,398,204	11,325,198
Wilmarth	303,646	5,170,263	7,265,649	153,131	168,520	29,016	21,797	235,896	80,000	-	13,427,919
Total	**14,100,859**	**298,699,489**	**427,940,558**	**7,071,745**	**8,140,800**	**1,732,655**	**5,470,810**	**13,816,706**	**1,235,881**	**1,398,307**	**779,607,809**

TABLE 4.2b
QUANTITY OF SCRAP METALS BY STATION
(pounds**)**

Wind Farms (Complete Removal)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I	5,913,057	43,858,999	534,453	6,015,842	2,085,396	58,407,747
Border Winds Project	4,404,257	23,658,643	400,839	3,819,509	1,564,047	33,847,295
Courtenay	5,906,025	35,509,601	534,453	5,092,678	2,085,396	49,128,153
Foxtail	5,655,813	32,880,310	400,839	4,514,897	1,564,047	45,015,907
Grand Meadow	3,862,624	33,764,540	358,083	5,302,782	1,397,215	44,685,245
Lake Benton II	3,244,453	22,905,242	261,714	3,326,828	1,026,369	30,764,606
Nobles	10,771,870	51,911,086	716,166	10,639,600	2,794,431	76,833,154
Pleasant Valley	6,238,545	37,955,390	534,453	5,092,678	2,085,396	51,906,462
Total (Complete Removal)	**45,996,644**	**282,443,812**	**3,741,000**	**43,804,815**	**14,602,298**	**390,588,569**

TABLE 4.2c
QUANTITY OF SCRAP METALS BY STATION
(pounds**)**

Wind Farms (Down to 48 inches below grade)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I (48 in.)	669,104	43,858,999	11,641	6,015,842	-	50,555,586
Border Winds Project (48 in.)	485,434	23,658,643	8,731	3,819,509	-	27,972,316
Courtenay (48 in.)	662,072	35,509,601	11,641	5,092,678	-	41,275,992
Foxtail (48 in.)	610,801	32,880,310	8,731	4,514,897	-	38,014,739
Grand Meadow (48 in.)	561,512	33,764,540	7,799	5,302,782	-	39,636,634
Lake Benton II (48 in.)	385,519	22,905,242	5,122	3,326,828	-	26,622,712
Nobles (48 in.)	1,306,946	51,911,086	15,599	10,639,600	-	63,873,231
Pleasant Valley (48 in.)	658,709	37,955,390	11,641	5,092,678	-	43,718,418
Total (Down 48 inch Removal)	**5,340,099**	**282,443,812**	**80,903**	**43,804,815**	**-**	**331,669,629**

TABLE 4.3a
SCRAP METAL CREDITS BY STATION
(thousands of 2019 dollars)

Fossil Stations

	Carbon Steel			Stainless Steel	Galvanized	Copper			Copper		
Station Name	**Cast Iron**	**No. 1**	**Mixed Scrap**	**SS-1**	**Steel**	**Insul Cbl**	**No. 2 Cu**	**Large Mtr**	**Nickel**	**Aluminum**	**Total**
Allen S . King	$ 232	$ 4,252	$ 4,181	$ 172	$ 4	$ 203	$ 1,231	$ 532	$ 1,639	$ -	$ 12,446
Angus Anson	$ 73	$ 811	$ 806	$ 273	$ 1	$ 81	$ 1,158	$ 69	$ 286	$ -	$ 3,559
Black Dog	$ 128	$ 2,827	$ 2,730	$ 574	$ 3	$ 264	$ 1,042	$ 520	$ 704	$ -	$ 8,792
Blue Lake	$ 44	$ 737	$ 1,306	$ 352	$ 1	$ 86	$ 1,114	$ 49	$ -	$ -	$ 3,688
Granite City	$ 32	$ 139	$ 298	$ 11	$ 1	$ 25	$ 246	$ 11	$ -	$ -	$ 763
Hennepin Island	$ -	$ 72	$ 142	$ 1	$ 0	$ 23	$ 93	$ -	$ -	$ -	$ 330
High Bridge	$ 66	$ 1,222	$ 1,452	$ 233	$ 3	$ 147	$ 1,379	$ 298	$ -	$ -	$ 4,799
Inver Hills	$ 16	$ 418	$ 942	$ 679	$ 0	$ -	$ 1,120	$ 2	$ -	$ -	$ 3,177
Key City	$ 32	$ 103	$ 295	$ 11	$ 1	$ 25	$ 223	$ 11	$ -	$ -	$ 702
Maplewood	$ 4	$ 235	$ 40	$ 81	$ 0	$ 9	$ 35	$ 0	$ -	$ -	$ 404
Minnesota Valley	$ 50	$ 1,334	$ 1,573	$ 413	$ 2	$ 89	$ 503	$ 408	$ 935	$ -	$ 5,307
Red Wing	$ 21	$ 597	$ 586	$ 343	$ 1	$ 38	$ 45	$ 69	$ 109	$ -	$ 1,809
Riverside	$ 56	$ 2,715	$ 3,766	$ 205	$ 2	$ 79	$ 1,243	$ 419	$ -	$ -	$ 8,484
Sherburne County	$ 312	$ 13,786	$ 14,449	$ 1,589	$ 16	$ 1,082	$ 1,863	$ 1,584	$ -	$ 0	$ 34,681
Sibley	$ 4	$ 188	$ 29	$ 77	$ 0	$ 9	$ 29	$ 2	$ -	$ -	$ 338
Wescott	$ 4	$ 821	$ 125	$ 141	$ 0	$ 44	$ 34	$ 1	$ -	$ 372	$ 1,541
Wilmarth	$ 24	$ 533	$ 565	$ 114	$ 1	$ 38	$ 45	$ 69	$ 254	$ -	$ 1,643
Total	**$ 1,097**	**$ 30,790**	**$ 33,285**	**$ 5,269**	**$ 36**	**$ 2,240**	**$ 11,403**	**$ 4,044**	**$ 3,928**	**$ 372**	**$ 92,464**

TABLE 4.3b
SCRAP METAL CREDITS BY STATION
(thousands of 2019 dollars)

Wind Farms (Complete Removal)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I	$ 748	$ 4,439	$ 1,126	$ 1,902	$ 604	$ 8,819
Border Winds Project	$ 557	$ 2,394	$ 845	$ 1,207	$ 453	$ 5,457
Courtenay	$ 747	$ 3,594	$ 1,126	$ 1,610	$ 604	$ 7,681
Foxtail	$ 715	$ 3,327	$ 845	$ 1,427	$ 453	$ 6,768
Grand Meadow	$ 489	$ 3,417	$ 755	$ 1,676	$ 405	$ 6,741
Lake Benton II	$ 410	$ 2,318	$ 552	$ 1,052	$ 297	$ 4,629
Nobles	$ 1,363	$ 5,253	$ 1,509	$ 3,363	$ 809	$ 12,298
Pleasant Valley	$ 789	$ 3,841	$ 1,126	$ 1,610	$ 604	$ 7,971
Total (Complete Removal)	**$ 5,819**	**$ 28,583**	**$ 7,885**	**$ 13,848**	**$ 4,228**	**$ 60,363**

TABLE 4.3c
SCRAP METAL CREDITS BY STATION
(thousands of 2019 dollars)

Wind Farms (Down to 48 inches below grade)

	Carbon Steel		Copper			
Station Name	**No. 1**	**Mixed Scrap**	**No. 2 Cu**	**Large Mtr**	**Aluminum**	**Total**
Blazing Star I (48 in.)	$ 85	$ 4,439	$ 25	$ 1,902	$ -	$ 6,449
Border Winds Project (48 in.)	$ 61	$ 2,394	$ 18	$ 1,207	$ -	$ 3,682
Courtenay (48 in.)	$ 84	$ 3,594	$ 25	$ 1,610	$ -	$ 5,312
Foxtail (48 in.)	$ 77	$ 3,327	$ 18	$ 1,427	$ -	$ 4,850
Grand Meadow (48 in.)	$ 71	$ 3,417	$ 16	$ 1,676	$ -	$ 5,181
Lake Benton II (48 in.)	$ 49	$ 2,318	$ 11	$ 1,052	$ -	$ 3,429
Nobles (48 in.)	$ 165	$ 5,253	$ 33	$ 3,363	$ -	$ 8,815
Pleasant Valley (48 in.)	$ 83	$ 3,841	$ 25	$ 1,610	$ -	$ 5,559
Total (Down 48 inch Removal)	**$ 676**	**$ 28,583**	**$ 171**	**$ 13,848**	**$ -**	**$ 43,277**

5. RESULTS

An estimate for dismantling each of the Xcel Energy fossil-fuel and wind farm generating stations in Minnesota and South Dakota was developed by applying the system and structures inventories against the associated unit cost factors and accounting for program support costs. A summary of each station's major cost categories is presented in Table 5.1 for the fossil stations, and in Table 5.2 for the wind farms.

5.1 FOSSIL STATIONS

Breakdowns of the major cost categories by unit and common facilities are provided in Tables 5.1a through 5.1q. Note that columns may not total due to rounding.

The following is an explanation of the contents of each line item in these tables:

Station Unit Rating (MWe) – This is the nominal electrical rating of each unit at the station. In Table 5.1 this represents the sum of all units on site.

Characterization / Temporary Services – The cost associated with performing a hazardous materials survey of the site prior to beginning field activities. Includes costs associated with de-energizing systems and isolation of the electrical systems in the buildings scheduled for dismantling. Costs for installing temporary services to support the dismantling are also included.

Worker Access – The cost associated with providing safe access to areas of the station being dismantled.

Pre-Demolition Cleaning (Boiler / Precipitator / Tanks) – The cost associated with cleaning coal-fired boilers and precipitators / baghouses, and associated flue-gas emission control systems. This line item also includes costs to clean acid and caustic storage tanks.

Asbestos / Lead Paint Remediation– The cost associated with remediating asbestos from the station prior to initiating dismantling activities. It should be noted that dismantling can proceed much more efficiently if asbestos containing materials have been removed. This line item also includes lead paint abatement from concrete surfaces in the buildings.

Equipment Removal – The cost associated with removing all station equipment (piping, valves, heat exchangers, tanks, electrical equipment, etc.).

Boiler(s) – The cost associated with removing the boiler.

Structures Demolition – The cost associated with demolishing the buildings and concrete foundations.

Backfill / Grade / Landscaping / Well Closure – The cost associated with backfilling below grade voids, and grading and landscaping the grounds to preclude erosion of soils. This line item also includes costs to seal groundwater monitoring wells.

Coal Yard Closure – The cost associated with removal and disposal of soil waste beneath the footprint of the coal field to a depth of 5 feet, and backfilling the void.

Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds / Ash Pond Dewatering – The cost associated with closure of the ponds on site, including placement of a cap on the pond(s) after backfilling.

Utility Management / Oversight – The staff directly assigned to manage the dismantling project, including planning, execution, oversight, and restoration.

Demolition Contractor Mgmt. / Super. / Safety Staff – The contractor's staff assigned to manage, engineer, and supervise the dismantling project, including site safety personnel.

Security – Personnel assigned to control access to the dismantling site.

Property Taxes – Not included in this estimate.

The following six items, grouped as Project Expenses, are calculated on a station basis, but are apportioned among the generating units on site by a ratio of the craft labor hours for each generating unit.

> *Shared Heavy Equipment / Operating Engineers* – The cost for renting / operating equipment in general use throughout the dismantling project (cranes, trucks, forklifts, front-end loaders, etc.).
>
> *Small Tool Allowance* – The cost for procuring small tools; this is consistent with R.S. Means 2019 Item 01 54 39.70-0100.
>
> *Utilities Allowance (Office Equip & Supplies / Telephone, Electric etc.)* – The cost for procuring utility services and office supplies in support of the field office for the utility management and demolition contractor staffs.

Permits – The cost of obtaining permits; this is consistent with R.S. Means 2019 Item 01 41 26.50.

Demolition Contractors Insurance – The cost of the demolition contractors insurance; the value is consistent with the R.S. Means 2019 Item 01 31 13.30, lines 0020, 0200, and 0600.

Demolition Contractors Fee – A fee applied to contractor activities; this represents the Contractors overhead and profit payment for the project and is consistent with R.S. Means 2019 Item 01 31 13.80 lines 0350, 0400 and 0450.

Contingency – The cost to cover expenses for unforeseen events that are likely to occur. The estimate assumes 25% (consistent with TLG's experience for similarly highly regulated activities in the nuclear industry) for the asbestos remediation work, and 15% for all other project activities, consistent with the R.S. Means 2019 Item 01 21 16.50 lines 0050 and 0100.

Scrap Credit – A credit to the project for the recovery of scrap metals. This corresponds to value shown in Table 4.3a through 4.3c.

The following is an explanation of the contents of each column in the 5.1 Tables:

Unit – Costs directly attributed to the physical work associated with dismantling a generating unit.

Common – Costs directly attributed to the physical work associated with dismantling facilities shared by more than one unit.

Station – Costs associated with supporting the physical dismantling work for a station.

Station Total – The summation of all Unit columns, plus Common and Station columns.

This study provides an estimate for dismantling under current requirements, based on present-day costs and available technology. As inputs to the cost model change over time, such as labor rates, equipment costs, scrap metal value, etc., this cost estimate should be reviewed and updated to reflect these changes.

TABLE 5.1

SUMMARY OF ACTIVITY COSTS – FOSSIL STATIONS
(2019 Dollars)

Activities (Costs)	Allen S . King	Angus Anson	Black Dog	Blue Lake	Granite City	Hennepin Island	High Bridge	Inver Hills	Key City	Maplewood	Minnesota Valley	Red Wing	Riverside	Sherburne County	Sibley	Wescott	Wilmarth	Fleet Totals
Station Rating (MWe)	511	386	526	545	0	14	606	371	0	0	0	18	590	2238	0	0	18	5778
Characterization / Temporary Services	351,606	297,606	907,818	330,606	239,606	237,606	456,606	263,439	239,606	125,803	519,212	471,212	1,035,818	1,136,818	125,803	159,404	471,000	7,369,573
Worker Access	630,789	-	793,518	-	-	-	-	-	-	-	187,086	123,388	-	1,988,310	-	-	123,388	3,846,477
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	1,080,300	240,000	-	-	-	-	-	342,500	-	-	500,900	515,600	526,800	3,243,150	-	-	515,600	6,964,850
Asbestos / Lead Paint Remediation	4,284,988	142,847	4,731,083	-	-	146,899	-	-	-	-	3,576,022	1,443,877	3,167,908	5,517,768	-	-	1,443,877	24,455,269
Equipment Removal	9,548,255	5,634,452	7,019,825	5,928,449	874,216	316,678	4,605,839	4,440,318	874,216	1,362,397	2,863,962	2,030,731	4,234,148	30,534,794	1,129,907	4,647,516	1,746,502	87,792,206
Boiler(s)	3,460,641	-	3,167,478	-	-	-	-	-	-	-	1,193,285	540,184	2,693,576	12,984,236	-	-	841,285	24,880,685
Structures Demolition	12,492,666	1,769,185	6,719,654	2,723,261	948,877	1,605,413	4,537,604	1,533,028	802,108	116,305	3,871,934	2,505,253	9,411,897	35,356,935	84,384	763,648	1,999,579	87,241,729
Backfill / Grade / Landscaping / Well Closure	3,697,788	1,133,560	2,767,357	1,529,390	383,922	790,474	1,742,979	1,343,018	243,348	161,005	1,432,771	1,079,539	2,498,203	9,987,445	164,731	756,289	780,770	30,492,588
Coal Yard Closure	10,718,358	-	-	-	-	-	-	-	-	-	-	-	-	8,264,365	-	-	-	18,982,723
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds / Ash Pond Dewatering	950,000	-	3,215,960	-	-	-	-	-	-	-	-	457,152	-	23,923,905	-	-	1,400,239	29,947,256
Utility Management / Oversight	3,027,199	945,676	3,459,078	1,580,835	784,321	778,453	1,618,917	1,333,298	781,800	871,780	1,979,405	1,119,169	3,482,165	3,860,869	839,852	1,003,663	1,119,169	28,585,648
Demolition Contractor Mgmt / Super. / Safety Staff	3,699,644	886,053	4,873,798	1,562,983	488,361	401,322	1,654,047	971,065	482,147	550,634	2,196,028	1,130,906	4,775,533	6,129,664	499,554	1,028,973	1,130,906	32,461,621
Security	776,195	197,940	960,031	197,940	115,679	145,241	208,222	131,103	114,394	194,084	298,195	272,488	965,867	1,135,113	177,374	227,502	272,488	6,389,856
Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Project Expenses																		
Shared Heavy Equipment / Operating Engineers	3,194,695	882,518	4,301,582	1,441,364	476,691	622,535	1,526,730	886,484	470,350	863,495	2,010,686	1,209,872	4,169,727	5,525,323	781,061	1,028,362	1,209,872	30,601,346
Small Tool Allowance	683,023	173,521	508,038	206,202	44,900	57,909	220,828	147,564	39,153	33,294	262,821	153,819	406,870	1,936,030	28,080	123,849	138,068	5,163,971
Utilities Allowance	52,508	30,400	64,945	30,400	17,766	22,306	31,979	20,135	17,569	29,807	45,797	41,849	65,339	76,789	27,241	34,940	41,849	651,617
Permits	685,566	139,877	488,388	171,908	43,429	52,514	184,708	124,344	39,606	40,534	233,256	146,292	412,323	1,832,569	35,510	106,787	148,037	4,885,649
Demolition Contractors Insurance	1,613,171	329,137	1,149,202	404,509	102,191	123,569	434,626	292,589	93,195	95,379	548,864	344,233	970,216	4,312,127	83,556	251,276	348,338	11,496,176
Demolition Contractors Fee	6,680,544	1,346,638	4,479,356	1,595,761	391,450	496,988	1,717,737	1,174,177	352,394	353,503	2,155,825	1,382,875	3,699,103	18,327,570	307,534	984,009	1,401,050	46,846,515
Sub-Total	67,627,939	14,149,409	49,607,111	17,703,605	4,911,409	5,797,909	18,940,824	13,003,063	4,549,886	4,798,021	23,876,048	14,968,441	42,515,494	176,073,780	4,284,587	11,116,217	15,132,016	489,055,758
Contingency	10,572,690	2,136,696	7,914,175	2,655,541	736,711	884,376	2,841,124	1,950,459	682,483	719,703	3,939,009	2,389,654	6,694,115	26,962,844	642,688	1,667,433	2,414,190	75,803,891
Project Total (before scrap credit)	78,200,628	16,286,105	57,521,286	20,359,146	5,648,121	6,682,285	21,781,947	14,953,523	5,232,369	5,517,724	27,815,058	17,358,094	49,209,609	203,036,624	4,927,275	12,783,650	17,546,206	564,859,649
Scrap Credit	(12,446,046)	(3,559,337)	(8,791,629)	(3,688,291)	(762,978)	(329,908)	(4,798,599)	(3,176,879)	(702,022)	(404,310)	(5,307,403)	(1,808,929)	(8,484,150)	(34,681,107)	(338,307)	(1,541,232)	(1,642,767)	(92,463,894)
Project Total	65,754,582	12,726,768	48,729,657	16,670,855	4,885,143	6,352,377	16,983,348	11,776,644	4,530,347	5,113,414	22,507,655	15,549,165	40,725,459	168,355,517	4,588,968	11,242,417	15,903,439	472,395,755

TABLE 5.1a

ALLEN S. KING STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Common	Station	Station Total
Allen S . King Unit Rating (MWe)	511			511
Characterization / Temporary Services	150,000	-	201,606	351,606
Worker Access	630,789	-		630,789
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	1,000,300	80,000		1,080,300
Asbestos / Lead Paint Remediation	4,284,988	-		4,284,988
Equipment Removal	7,865,365	1,682,890		9,548,255
Boiler(s)	3,460,641	-		3,460,641
Structures Demolition	10,016,294	2,476,372		12,492,666
Backfill / Grade / Landscaping / Well Closure	2,605,976	977,821	113,991	3,697,788
Coal Yard Closure		10,718,358		10,718,358
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds		950,000		950,000
Utility Management / Oversight			3,027,199	3,027,199
Demolition Contractor Management / Supervisory / Safety Staff			3,699,644	3,699,644
Security			776,195	776,195
Property Taxes	-	-	-	0
Project Expenses				
Shared Heavy Equipment / Operating Engineers			3,194,695	3,194,695
Small Tool Allowance	580,281	102,742	n/a	683,023
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)			52,508	52,508
Permits			685,566	685,566
Demolition Contractors Insurance			1,613,171	1,613,171
Demolition Contractors Fee			6,680,544	6,680,544
Sub-Total				67,627,939
Contingency				10,572,690
Project Total (before scrap credit)				78,200,628
Scrap Credit	(11,244,369)	(1,201,677)	-	(12,446,046)
Project Total				65,754,582

TABLE 5.1b

ANGUS ANSON STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Common	Station	Station Total
Angus Anson Unit Rating (MWe)	0	109	109	168			386
Characterization / Temporary Services	25,000	22,000	22,333	26,667	-	201,606	297,606
Pre-Demolition Cleaning (Tanks)	-	-	-	-	240,000		240,000
Lead Paint Remediation	142,847	-	-	-	-		142,847
Equipment Removal	2,642,304	589,684	592,643	1,471,114	338,707		5,634,452
Structures Demolition	1,044,734	158,683	161,649	343,728	60,391		1,769,185
Backfill / Grade / Landscaping / Well Closure	541,304	74,092	75,477	150,687	192,001	100,000	1,133,560
Utility Management / Oversight						945,676	945,676
Demolition Contractor Management / Supervisory / Safety Staff						886,053	886,053
Security						197,940	197,940
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						882,518	882,518
Small Tool Allowance	87,924	16,889	17,042	39,844	11,822	n/a	173,521
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						30,400	30,400
Permits						139,877	139,877
Demolition Contractors Insurance						329,137	329,137
Demolition Contractors Fee						1,346,638	1,346,638
Sub-Total							14,149,409
Contingency							2,136,696
Project Total (before scrap credit)							16,286,105
Scrap Credit	(1,394,645)	(547,154)	(554,872)	(980,393)	(82,273)	-	(3,559,337)
Project Total							12,726,768

TABLE 5.1c

BLACK DOG STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 2	Unit 3	Unit 5	Unit 6	Common	Station	Station Total
Black Dog Unit Rating (MWe)	117	0	181	228			526
Characterization / Temporary Services	64,000	67,000	79,000	93,000	-	604,818	907,818
Worker Access	387,123	406,395	-	-	-		793,518
Asbestos Remediation	1,956,422	1,969,760	-	800,000	4,902		4,731,083
Equipment Removal	2,289,715	2,297,438	1,366,958	981,902	83,813		7,019,825
Boiler(s)	1,750,299	1,417,179	-	-	-		3,167,478
Structures Demolition	823,953	1,315,352	1,535,212	2,081,747	963,391		6,719,654
Backfill / Grade / Landscaping / Well Closure	438,647	460,484	462,694	435,600	869,932	100,000	2,767,357
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds					3,215,960		3,215,960
Utility Management / Oversight						3,459,078	3,459,078
Demolition Contractor Management / Supervisory / Safety Staff						4,873,798	4,873,798
Security						960,031	960,031
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						4,301,582	4,301,582
Small Tool Allowance	154,203	158,672	68,877	87,845	38,441	n/a	508,038
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						64,945	64,945
Permits						488,388	488,388
Demolition Contractors Insurance						1,149,202	1,149,202
Demolition Contractors Fee						4,479,356	4,479,356
Sub-Total							49,607,111
Contingency							7,914,175
Project Total (before scrap credit)							57,521,286
Scrap Credit	(2,502,344)	(2,983,623)	(1,370,844)	(1,737,309)	(197,508)	-	(8,791,629)
Project Total							48,729,657

TABLE 5.1d

BLUE LAKE STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Unit 7	Unit 8	Common	Station	Station Total
Blue Lake Unit Rating (MWe)	50	50	46	48	174	177			545
Characterization / Temporary Services	12,250	12,250	12,250	12,250	40,000	40,000	-	201,606	330,606
Equipment Removal	566,731	566,731	566,731	566,731	1,472,140	1,472,140	717,247		5,928,449
Structures Demolition	234,043	203,009	203,009	203,009	461,241	461,241	957,708		2,723,261
Backfill / Grade / Landscaping	160,053	160,053	160,053	160,053	265,653	265,653	357,874	-	1,529,390
Utility Management / Oversight								1,580,835	1,580,835
Demolition Contractor Management / Supervisory / Safety Staff								1,562,983	1,562,983
Security								197,940	197,940
Property Taxes	-	-	-	-	-	-	-	-	0
Project Expenses									
Shared Heavy Equipment / Operating Engineers								1,441,364	1,441,364
Small Tool Allowance	19,462	18,841	18,841	18,841	44,781	44,781	40,657	n/a	206,202
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)								30,400	30,400
Permits								171,908	171,908
Demolition Contractors Insurance								404,509	404,509
Demolition Contractors Fee								1,595,761	1,595,761
Sub-Total									17,703,605
Contingency (excluding activities currently under contract)									2,655,541
Project Total (before scrap credit)									20,359,146
Scrap Credit	(473,687)	(415,070)	(415,070)	(415,070)	(862,163)	(862,163)	(245,069)	-	(3,688,291)
Project Total									16,670,855

TABLE 5.1e

GRANITE CITY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Common	Station	Station Total
Granite City Unit Rating (MWe)	0	0	0	0			0
Characterization / Temporary Services	9,500	9,500	9,500	9,500	-	201,606	239,606
Equipment Removal	218,554	218,554	218,554	218,554	-		874,216
Structures Demolition	142,423	142,423	142,423	142,423	379,183		948,877
Backfill / Grade / Landscaping	83,590	83,590	83,590	83,590	49,563	-	383,922
Utility Management / Oversight						784,321	784,321
Demolition Contractor Management / Supervisory / Safety Staff						488,361	488,361
Security						115,679	115,679
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						476,691	476,691
Small Tool Allowance	9,081	9,081	9,081	9,081	8,575	n/a	44,900
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						17,766	17,766
Permits						43,429	43,429
Demolition Contractors Insurance						102,191	102,191
Demolition Contractors Fee						391,450	391,450
Sub-Total							4,911,409
Contingency							736,711
Project Total (before scrap credit)							5,648,121
Scrap Credit	(159,623)	(159,623)	(159,623)	(159,623)	(124,486)	-	(762,978)
Project Total							4,885,143

TABLE 5.1f

HENNEPIN ISLAND STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1-5	Station	Station Total
Hennepin Island Unit Rating (MWe)	14		14
Characterization / Temporary Services	36,000	201,606	237,606
Lead Paint Remediation	146,899		146,899
Equipment Removal	316,678		316,678
Structures Demolition	1,605,413		1,605,413
Grade / Landscaping	790,474	-	790,474
Utility Management / Oversight		778,453	778,453
Demolition Contractor Management / Supervisory / Safety Staff		401,322	401,322
Security		145,241	145,241
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		622,535	622,535
Small Tool Allowance	57,909	n/a	57,909
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		22,306	22,306
Permits		52,514	52,514
Demolition Contractors Insurance		123,569	123,569
Demolition Contractors Fee		496,988	496,988
Sub-Total			5,797,909
Contingency			884,376
Project Total (before scrap credit)			6,682,285
Scrap Credit	(329,908)	-	(329,908)
Project Total			6,352,377

TABLE 5.1g

HIGH BRIDGE STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 7	Unit 8	Unit 9	Common	Station	Station Total
High Bridge Unit Rating (MWe)	185	185	236			606
Characterization / Temporary Services	79,000	79,000	97,000	-	201,606	456,606
Equipment Removal	1,393,993	1,393,993	1,452,905	364,947		4,605,839
Boiler(s)	-	-	-	-		0
Structures Demolition	1,109,013	1,109,013	1,777,707	541,872		4,537,604
Backfill / Grade / Landscaping / Well Closure	327,086	327,086	801,030	187,777	100,000	1,742,979
Utility Management / Oversight					1,618,917	1,618,917
Demolition Contractor Management / Supervisory / Safety Staff					1,654,047	1,654,047
Security					208,222	208,222
Property Taxes	-	-	-	-	-	0
Project Expenses						
Shared Heavy Equipment / Operating Engineers					1,526,730	1,526,730
Small Tool Allowance	58,182	58,182	82,573	21,892	n/a	220,828
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)					31,979	31,979
Permits					184,708	184,708
Demolition Contractors Insurance					434,626	434,626
Demolition Contractors Fee					1,717,737	1,717,737
Sub-Total						18,940,824
Contingency						2,841,124
Project Total (before scrap credit)						21,781,947
Scrap Credit	(1,418,437)	(1,418,437)	(1,846,014)	(115,711)	-	(4,798,599)
Project Total						16,983,348

TABLE 5.1h

INVER HILLS STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Common	Station	Station Total
Inver Hills Unit Rating (MWe)	62	62	62	62	61	62			371
Characterization / Temporary Services	8,833	8,833	8,833	8,833	8,833	8,833	8,833	201,606	263,439
Pre-Demolition Cleaning (Tanks)	-	-	-	-	-	-	342,500		342,500
Equipment Removal	696,798	696,798	696,798	696,798	696,798	696,798	259,531		4,440,318
Boiler(s)	-	-	-	-	-	-	-		0
Structures Demolition	232,167	232,167	232,167	232,167	232,167	232,167	140,023		1,533,028
Backfill / Grade / Landscaping	192,205	192,205	192,205	192,205	192,205	192,205	189,786	-	1,343,018
Utility Management / Oversight								1,333,298	1,333,298
Demolition Contractor Management / Supervisory / Safety Staff								971,065	971,065
Security								131,103	131,103
Property Taxes	-	-	-	-	-	-	-	-	0
Project Expenses									
Shared Heavy Equipment / Operating Engineers								886,484	886,484
Small Tool Allowance	22,600	22,600	22,600	22,600	22,600	22,600	11,963	n/a	147,564
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)								20,135	20,135
Permits								124,344	124,344
Demolition Contractors Insurance								292,589	292,589
Demolition Contractors Fee								1,174,177	1,174,177
Sub-Total									13,003,063
Contingency									1,950,459
Project Total (before scrap credit)									14,953,523
Scrap Credit	(517,223)	(517,223)	(517,223)	(517,223)	(517,223)	(517,223)	(73,541)	-	(3,176,879)
Project Total									11,776,644

TABLE 5.1i

KEY CITY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Common	Station	Station Total
Key City Unit Rating (MWe)	0	0	0	0			0
Characterization / Temporary Services	9,500	9,500	9,500	9,500	-	201,606	239,606
Equipment Removal	218,554	218,554	218,554	218,554	-		874,216
Structures Demolition	107,785	107,785	107,785	107,785	370,968		802,108
Backfill / Grade / Landscaping	50,591	50,591	50,591	50,591	40,982	-	243,348
Utility Management / Oversight						781,800	781,800
Demolition Contractor Management / Supervisory / Safety Staff						482,147	482,147
Security						114,394	114,394
Property Taxes	-	-	-	-	-	-	0
Project Expenses							
Shared Heavy Equipment / Operating Engineers						470,350	470,350
Small Tool Allowance	7,729	7,729	7,729	7,729	8,239	n/a	39,153
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)						17,569	17,569
Permits						39,606	39,606
Demolition Contractors Insurance						93,195	93,195
Demolition Contractors Fee						352,394	352,394
Sub-Total							4,549,886
Contingency							682,483
Project Total (before scrap credit)							5,232,369
Scrap Credit	(144,885)	(144,885)	(144,885)	(144,885)	(122,482)	-	(702,022)
Project Total							4,530,347

TABLE 5.1j

MAPLEWOOD GAS PLANT
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Station	Station Total
Maplewood Unit Rating (MWe)	0		0
Characterization / Temporary Services	25,000	100,803	125,803
Equipment Removal	1,362,397		1,362,397
Structures Demolition	116,305		116,305
Grade / Landscaping	161,005	-	161,005
Utility Management / Oversight		871,780	871,780
Demolition Contractor Management / Supervisory / Safety Staff		550,634	550,634
Security		194,084	194,084
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		863,495	863,495
Small Tool Allowance	33,294	n/a	33,294
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		29,807	29,807
Permits		40,534	40,534
Demolition Contractors Insurance		95,379	95,379
Demolition Contractors Fee		353,503	353,503
Sub-Total			4,798,021
Contingency			719,703
Project Total (before scrap credit)			5,517,724
Scrap Credit	(404,310)	-	(404,310)
Project Total			5,113,414

TABLE 5.1k

MINNESOTA VALLEY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	*Unit 1*	*Unit 2*	*Unit 3*	*Common*	*Station*	*Station Total*
Minnesota Valley Unit Rating (MWe)	0	0	0			0
Characterization / Temporary Services	34,000	34,000	48,000		403,212	519,212
Worker Access	-	-	187,086	-		187,086
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	166,967	166,967	166,967	-		500,900
Asbestos / Lead Paint Remediation	124,640	124,640	3,326,742	-		3,576,022
Equipment Removal	353,302	353,302	2,157,358	-		2,863,962
Boiler(s)	255,835	255,835	681,615	-		1,193,285
Structures Demolition	756,380	756,380	2,059,095	300,078		3,871,934
Backfill / Grade / Landscaping / Well Closure	415,645	415,645	396,692	104,790	100,000	1,432,771
Utility Management / Oversight					1,979,405	1,979,405
Demolition Contractor Management / Supervisory / Safety Staff					2,196,028	2,196,028
Security					298,195	298,195
Property Taxes	-	-	-	-	-	0
Project Expenses						
Shared Heavy Equipment / Operating Engineers					2,010,686	2,010,686
Small Tool Allowance	38,796	38,796	177,132	8,097	n/a	262,821
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)					45,797	45,797
Permits					233,256	233,256
Demolition Contractors Insurance					548,864	548,864
Demolition Contractors Fee					2,155,825	2,155,825
Sub-Total						23,876,048
Contingency						3,939,009
Project Total (before scrap credit)						27,815,058
Scrap Credit	(1,232,488)	(1,232,488)	(2,840,688)	(1,738)	-	(5,307,403)
Project Total						22,507,655

TABLE 5.1l

RED WING STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Common	Station	Station Total
Red Wing Unit Rating (MWe)	9	9			18
Characterization / Temporary Services	34,000	34,000	-	403,212	471,212
Worker Access	61,694	61,694	-		123,388
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	257,800	257,800	-		515,600
Asbestos / Lead Paint Remediation	721,939	721,939	-		1,443,877
Equipment Removal	780,906	780,906	468,918		2,030,731
Boiler(s)	270,092	270,092	-		540,184
Structures Demolition	731,187	731,187	1,042,878		2,505,253
Backfill / Grade / Landscaping / Well Closure	215,931	215,931	547,677	100,000	1,079,539
Ash Landfills / Ash Ponds & Landfills Inculding Evaporation Ponds			457,152		457,152
Utility Management / Oversight				1,119,169	1,119,169
Demolition Contractor Management / Supervisory / Safety Staff				1,130,906	1,130,906
Security				272,488	272,488
Property Taxes	-	-	-	-	0
Project Expenses					
Shared Heavy Equipment / Operating Engineers				1,209,872	1,209,872
Small Tool Allowance	56,315	56,315	41,189	n/a	153,819
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)				41,849	41,849
Permits				146,292	146,292
Demolition Contractors Insurance				344,233	344,233
Demolition Contractors Fee				1,382,875	1,382,875
Sub-Total					14,968,441
Contingency					2,389,654
Project Total (before scrap credit)					17,358,094
Scrap Credit	(662,363)	(662,363)	(484,203)	-	(1,808,929)
Project Total					15,549,165

TABLE 5.1m

RIVERSIDE STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 6 Boiler	Unit 7 Boiler	Unit 7 Turbine	Unit 8	Unit 9	Unit 10	Commom	Station	Station Total
Riverside Unit Rating (MWe)	44	44	160	0	171	171			590
Characterization / Temporary Services	48,000	48,000	80,000	93,000	81,000	81,000	-	604,818	1,035,818
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	170,600	170,600	-	170,600	-	-	15,000		526,800
Asbestos Remediation	1,025,353	1,025,353	-	1,117,201	-	-	-		3,167,908
Equipment Removal	-	-	987,364	473,484	1,377,540	1,377,540	18,220		4,234,148
Boiler(s)	875,389	875,389	-	942,798	-	-	-		2,693,576
Structures Demolition	1,041,505	1,041,505	574,865	2,627,561	952,584	952,584	2,221,292		9,411,897
Backfill / Grade / Landscaping / Well Closure	197,838	197,838	364,420	590,917	246,508	246,508	554,174	100,000	2,498,203
Utility Management / Oversight								3,482,165	3,482,165
Demolition Contractor Management / Supervisory / Safety Staff								4,775,533	4,775,533
Security								965,867	965,867
Property Taxes			-		-		-	-	0
Project Expenses									
Shared Heavy Equipment / Operating Engineers								4,169,727	4,169,727
Small Tool Allowance	63,762	63,762	40,133	116,899	33,220	33,220	55,874	n/a	406,870
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)								65,339	65,339
Permits								412,323	412,323
Demolition Contractors Insurance								970,216	970,216
Demolition Contractors Fee								3,699,103	3,699,103
Sub-Total									42,515,494
Contingency									6,694,115
Project Total (before scrap credit)									49,209,609
Scrap Credit	(1,202,298)	(1,202,298)	(1,141,914)	(2,432,111)	(1,179,549)	(1,179,549)	(146,430)	-	(8,484,150)
Project Total									40,725,459

TABLE 5.1n

SHERBURNE COUNTY STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Unit 3	Common	Station	Station Total
Sherburne County Unit Rating (MWe)	680	682	876			2238
Characterization / Temporary Services	171,000	171,000	190,000	-	604,818	1,136,818
Worker Access	642,334	642,334	703,642	-		1,988,310
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	1,081,050	1,081,050	1,081,050	-		3,243,150
Asbestos Remediation	2,508,884	2,508,884	-	500,000		5,517,768
Equipment Removal	5,699,637	5,547,162	6,568,928	4,670,760		22,486,487
Boiler(s)	4,182,168	4,182,168	4,619,900	-		12,984,236
Turbine Generator & Condensor	609,899	609,899	686,634			1,906,432
Exhaust Gas Treatment Equipment and Structures	4,245,955	4,398,430	4,741,985			13,386,370
Structures Demolition	7,038,228	7,038,228	7,657,026	6,378,958		28,112,441
Backfill / Grade / Landscaping / Well Closure	1,656,105	1,656,105	1,814,172	4,761,063	100,000	9,987,445
Coal Yard Closure				8,264,365		8,264,365
Ash Landfills / Ash Ponds & Landfills Including Evaporation Ponds / Ash Pond Dewatering			3,169,905	20,754,000		23,923,905
Utility Management / Oversight	1,079,289	1,079,289	1,208,276	494,016		3,860,869
Demolition Contractor Management / Supervisory / Safety Staff	1,713,520	1,713,520	1,918,305	784,319		6,129,664
Security	317,316	317,316	355,239	145,243		1,135,113
Property Taxes	-	-	-	-	-	0
Project Expenses						
Shared Heavy Equipment / Operating Engineers	1,544,579	1,544,579	1,729,174	706,991		5,525,323
Small Tool Allowance	535,084	535,084	539,646	326,216	n/a	1,936,030
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)					76,789	76,789
Permits					1,832,569	1,832,569
Demolition Contractors Insurance					4,312,127	4,312,127
Demolition Contractors Fee					18,327,570	18,327,570
Sub-Total						176,073,780
Contingency						26,962,844
Project Total (before scrap credit)						203,036,624
Scrap Credit	(9,982,485)	(9,982,485)	(12,096,244)	(2,619,893)	-	(34,681,107)
Project Total						168,355,517

TABLE 5.1o

SIBLEY GAS PLANT
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Station	Station Total
Sibley Unit Rating (MWe)	0		0
Characterization / Temporary Services	25,000	100,803	125,803
Equipment Removal	1,129,907		1,129,907
Structures Demolition	84,384		84,384
Grade / Landscaping	164,731	-	164,731
Utility Management / Oversight		839,852	839,852
Demolition Contractor Management / Supervisory / Safety Staff		499,554	499,554
Security		177,374	177,374
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		781,061	781,061
Small Tool Allowance	28,080	n/a	28,080
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		27,241	27,241
Permits		35,510	35,510
Demolition Contractors Insurance		83,556	83,556
Demolition Contractors Fee		307,534	307,534
Sub-Total			4,284,587
Contingency			642,688
Project Total (before scrap credit)			4,927,275
Scrap Credit	(338,307)	-	(338,307)
Project Total			4,588,968

TABLE 5.1p

WESCOTT GAS PLANT
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Station	Station Total
Wescott Unit Rating (MWe)	0		0
Characterization / Temporary Services	25,000	134,404	159,404
Equipment Removal	4,647,516		4,647,516
Structures Demolition	763,648		763,648
Grade / Landscaping	756,289	-	756,289
Utility Management / Oversight		1,003,663	1,003,663
Demolition Contractor Management / Supervisory / Safety Staff		1,028,973	1,028,973
Security		227,502	227,502
Property Taxes	-	-	0
Project Expenses			
Shared Heavy Equipment / Operating Engineers		1,028,362	1,028,362
Small Tool Allowance	123,849	n/a	123,849
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)		34,940	34,940
Permits		106,787	106,787
Demolition Contractors Insurance		251,276	251,276
Demolition Contractors Fee		984,009	984,009
Sub-Total			11,116,217
Contingency			1,667,433
Project Total (before scrap credit)			12,783,650
Scrap Credit	(1,541,232)	-	(1,541,232)
Project Total			11,242,417

TABLE 5.1q

WILMARTH STATION
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Activities	Unit 1	Unit 2	Common	Station	Station Total
Wilmarth Unit Rating (MWe)	9	9			18
Characterization / Temporary Services	34,000	34,000	-	403,000	471,000
Worker Access	61,694	61,694	-		123,388
Pre-Demolition Cleaning (Boiler / Precipitator / Tanks)	257,800	257,800	-		515,600
Asbestos / Lead Paint Remediation	721,939	721,939	-		1,443,877
Equipment Removal	780,906	780,906	184,689		1,746,502
Boiler(s)	420,643	420,643	-		841,285
Structures Demolition	626,917	626,917	745,744		1,999,579
Backfill / Grade / Landscaping / Well Closure	217,690	217,690	245,389	100,000	780,770
Ash Landfills			1,400,239		1,400,239
Utility Management / Oversight				1,119,169	1,119,169
Demolition Contractor Management / Supervisory / Safety Staff				1,130,906	1,130,906
Security				272,488	272,488
Property Taxes	-	-	-	-	0
Project Expenses					
Shared Heavy Equipment / Operating Engineers				1,209,872	1,209,872
Small Tool Allowance	57,276	57,276	23,516	n/a	138,068
Utilities Allowance (Office Equip & supplies / Telephone, Electric etc.)				41,849	41,849
Permits				148,037	148,037
Demolition Contractors Insurance				348,338	348,338
Demolition Contractors Fee				1,401,050	1,401,050
Sub-Total					15,132,016
Contingency					2,414,190
Project Total (before scrap credit)					17,546,206
Scrap Credit	(737,645)	(737,645)	(167,478)	-	(1,642,767)
Project Total					15,903,439

5.2 WIND FARMS

An estimate for dismantling each of the Xcel Energy wind farm generating stations in Minnesota and North Dakota was developed by applying the system and structures inventories against the associated unit cost factors and accounting for program support costs. A summary of each wind farm's major cost categories is presented in Table 5.2. Breakdowns of the major cost categories by wind farm are provided in Tables 5.2a through 5.2p. Note that columns may not total due to rounding.

The following is an explanation of the contents of each line item in these tables:

TURBINE SITE REMOVAL

Dismantle Wind Turbine Generators – The cost associated with removal of the nacelle, hub, blades and tower. Also included is a percentage of the utility, DOC, and security staffing, miscellaneous expenses, and site characterization costs.

Haul Off of Materials (Trucking/Rail) – The cost associated with the transportation of the scrap material.

Foundation Removal – The cost of removal of the WTG concrete foundation or in the 48-inch scenario, the pedestal removal.

Crane Mobilization & Demobilization – All heavy equipment costs.

SITE CIVIL WORK REMOVAL

Balance of Site Civil Work Removals – The cost associated with backfilling below grade voids, and grading and landscaping the grounds to preclude erosion of soils. Also included is a percentage of the utility, DOC, and security staffing, miscellaneous expenses and site characterization costs.

COLLECTION SYSTEM REMOVAL

Remove Collection Cable, Remove Junction Boxes & Turbine Switchgears – The cost associated with excavation of the cable and back-fill of the trench. Also included is a percentage of the utility, DOC, and security staffing, miscellaneous expenses and site characterization costs.

Contingency (15%) - The cost to cover expenses for unforeseen events that are likely to occur.

Approximate scrap value of components – A credit to the project for the recovery of scrap metals. This corresponds to value shown in Table 4.3b through 4.3c.

TABLE 5.2

SUMMARY OF ACTIVITY COSTS – WIND FARMS
(2019 Dollars)

ITEM	DESCRIPTION	Blazing Star I AMOUNT	Blazing Star I (48 in.) AMOUNT	Border Winds Project AMOUNT	Border Winds Project (48 in.) AMOUNT	Courtenay AMOUNT	Courtenay (48 in.) AMOUNT	Foxtail AMOUNT	Foxtail (48 in.) AMOUNT
1	TURBINE SITE REMOVAL								
1a	Dismantle Wind Turbine Generators - Model 1	$1,392,653	$1,437,495	$11,136,713	$11,604,079	$13,597,829	$13,970,467	$993,756	$1,025,000
	Dismantle Wind Turbine Generators - Model 2	$12,625,322	$13,028,894	$0	$0	$0	$0	$9,723,737	$10,027,257
1b	Haul Off of Materials (Trucking/Rail)	$3,053,850	$2,643,300	$1,769,707	$1,462,533	$2,568,667	$2,158,116	$2,353,658	$1,987,602
1c	Foundation Removal - Model 1	$609,370	$73,272	$5,263,779	$585,008	$6,704,742	$801,686	$465,755	$54,629
	Foundation Removal - Model 2	$5,484,331	$659,444	$0	$0	$0	$0	$4,524,475	$530,685
1d	Crane Mobilization & Demobilization	$1,998,541	$1,903,425	$2,417,050	$2,283,888	$1,954,154	$1,846,356	$1,522,963	$1,453,212
	SUBTOTAL	**$25,164,068**	**$19,745,830**	**$20,587,249**	**$15,935,508**	**$24,825,391**	**$18,776,625**	**$19,584,343**	**$15,078,385**
2	SITE CIVIL WORK REMOVAL								
2a	Balance of Site Civil Work Removals	$10,397,806	$10,084,299	$8,909,810	$8,622,688	$11,048,476	$10,695,312	$8,406,384	$8,171,092
	SUBTOTAL	**$10,397,806**	**$10,084,299**	**$8,909,810**	**$8,622,688**	**$11,048,476**	**$10,695,312**	**$8,406,384**	**$8,171,092**
3	COLLECTION SYSTEM REMOVAL								
3a	Remove MV Collection Cable	$2,023,676	$408,958	$1,933,366	$397,071	$2,050,705	$407,251	$1,609,155	$324,523
3b	Remove Junction Boxes & Turbine Switchgears	$313,937	$31,394	$248,574	$24,857	$331,432	$33,143	$248,574	$24,857
	SUBTOTAL	**$2,337,613**	**$440,352**	**$2,181,939**	**$421,928**	**$2,382,137**	**$440,394**	**$1,857,729**	**$349,380**
	SITE SUBTOTAL	**$37,899,487**	**$30,270,481**	**$31,678,997**	**$24,980,125**	**$38,256,004**	**$29,912,331**	**$29,848,456**	**$23,598,856**
	CONTINGENGY (15%)	$5,684,923	$4,540,572	$4,751,850	$3,747,019	$5,738,401	$4,486,850	$4,477,268	$3,539,828
	Project Total (before scrap credit)	$43,584,410	$34,811,053	$36,430,847	$28,727,143	$43,994,405	$34,399,181	$34,325,724	$27,138,685
	APPROXIMATE SCRAP VALUE OF COMPONENTS	($8,818,650)	($6,449,499)	($5,456,601)	($3,681,527)	($7,680,961)	($5,311,810)	($6,767,995)	($4,850,452)
	TOTAL PRICE	**$34,765,760**	**$28,361,555**	**$30,974,246**	**$25,045,616**	**$36,313,443**	**$29,087,370**	**$27,557,729**	**$22,288,232**

ITEM	DESCRIPTION	Grand Meadow AMOUNT	Grand Meadow (48 in.) AMOUNT	Lake Benton II AMOUNT	Lake Benton II (48 in.) AMOUNT	Nobles AMOUNT	Nobles (48 in.) AMOUNT	Pleasant Valley AMOUNT	Pleasant Valley (48 in.) AMOUNT	Complete Removal AMOUNT	Removal (to to 48" depth) ITEM
1	TURBINE SITE REMOVAL										
1a	Dismantle Wind Turbine Generators - Model 1	$10,279,573	$10,906,283	$804,060	$837,777	$18,641,078	$19,146,628	$15,900,269	$16,381,957	$72,745,929	$75,309,687
	Dismantle Wind Turbine Generators - Model 2	$0	$0	$6,529,184	$6,792,178	$0	$0	$0	$0	$28,878,242	$29,848,328
1b	Haul Off of Materials (Trucking/Rail)	$2,336,369	$2,072,402	$1,608,528	$1,391,969	$4,017,223	$3,339,613	$2,713,931	$2,285,819	$20,421,933	$17,341,355
1c	Foundation Removal - Model 1	$3,416,996	$525,128	$302,318	$37,728	$7,736,964	$1,012,965	$6,787,708	$792,287	$31,287,631	$3,882,702
	Foundation Removal - Model 2	$0	$0	$2,358,079	$294,280	$0	$0	$0	$0	$12,366,885	$1,484,409
1d	Crane Mobilization & Demobilization	$2,201,454	$2,138,044	$1,015,680	$977,633	$1,947,813	$1,871,720	$2,150,726	$2,061,951	$15,208,380	$14,536,230
	SUBTOTAL	**$18,234,392**	**$15,641,858**	**$12,617,848**	**$10,331,565**	**$32,343,078**	**$25,370,926**	**$27,552,633**	**$21,522,014**	**$180,909,001**	**$142,402,711**
2	SITE CIVIL WORK REMOVAL										
2a	Balance of Site Civil Work Removals	$7,490,034	$7,343,033	$4,848,790	$4,759,976	$13,434,084	$13,038,736	$10,584,412	$10,237,618	$75,119,796	$72,952,756
	SUBTOTAL	**$7,490,034**	**$7,343,033**	**$4,848,790**	**$4,759,976**	**$13,434,084**	**$13,038,736**	**$10,584,412**	**$10,237,618**	**$75,119,796**	**$72,952,756**
3	COLLECTION SYSTEM REMOVAL										
3a	Remove MV Collection Cable	$1,697,809	$366,382	$1,054,685	$221,763	$2,399,425	$479,044	$2,165,432	$438,778	$14,934,254	$3,043,769
3b	Remove Junction Boxes & Turbine Switchgears	$210,338	$21,034	$138,132	$13,813	$420,675	$42,068	$313,937	$31,394	$2,225,597	$222,560
	SUBTOTAL	**$1,908,147**	**$387,416**	**$1,192,817**	**$235,576**	**$2,820,100**	**$521,112**	**$2,479,368**	**$470,172**	**$17,159,851**	**$3,266,329**
	SITE SUBTOTAL	**$27,632,572**	**$23,372,307**	**$18,659,455**	**$15,327,118**	**$48,597,262**	**$38,930,775**	**$40,616,414**	**$32,229,804**	**$273,188,648**	**$218,621,796**
	CONTINGENGY (15%)	$4,144,886	$3,505,846	$2,798,918	$2,299,068	$7,289,589	$5,839,616	$6,092,462	$4,834,471	$40,978,297	$32,793,269
	Project Total (before scrap credit)	$31,777,458	$26,878,153	$21,458,374	$17,626,185	$55,886,851	$44,770,391	$46,708,876	$37,064,275	$314,166,945	$251,415,066
	APPROXIMATE SCRAP VALUE OF COMPONENTS	($6,741,282)	($5,180,812)	($4,628,964)	($3,429,286)	($12,298,196)	($8,815,111)	($7,970,541)	($5,558,899)	($60,363,190)	($43,277,397)
	TOTAL PRICE	**$25,036,176**	**$21,697,340**	**$16,829,410**	**$14,196,899**	**$43,588,656**	**$35,955,280**	**$38,738,336**	**$31,505,376**	**$253,803,755**	**$208,137,669**

Note: Model 1 and Model 2 designate the two Models of WTG at Blazing Star I, Foxtail, and Lake Benton II.

TABLE 5.2a
Blazing Star I Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	Blazing Star I AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	10	EA	$139,265	$1,392,653
	Dismantle Wind Turbine Generators - V120	90	EA	$140,281	$12,625,322
1b	Haul Off of Materials (Trucking/Rail)	100	EA	30,539	$3,053,850
1c	Foundation Removal - V110	10	EA	$60,937	$609,370
	Foundation Removal - V120	90	EA	$60,937	$5,484,331
1d	Crane Mobilization & Demobilization	1	LS	$1,998,541	$1,998,541
		SUBTOTAL			**$25,164,068**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,397,806	$10,397,806
		SUBTOTAL			**$10,397,806**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,023,676	$2,023,676
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$313,937	$313,937
		SUBTOTAL			**$2,337,613**
		SITE SUBTOTAL			**$37,899,487**
	CONTINGENGY (15%)				$5,684,923
	Project Total (before scrap credit)				$43,584,410
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($8,818,650)
TOTAL PRICE					**$34,765,760**

TABLE 5.2b
Blazing Star I Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Blazing Star I (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	10	EA	$143,749	$1,437,495
	Dismantle Wind Turbine Generators - V120	90	EA	$144,765	$13,028,894
1b	Haul Off of Materials (Trucking/Rail)	100	EA	26,433	$2,643,300
1c	Foundation Removal V110	10	EA	$7,327	$73,272
	Foundation Removal V120	90	EA	$7,327	$659,444
1d	Crane Mobilization & Demobilization	1	LS	$1,903,425	$1,903,425
		SUBTOTAL			**$19,745,830**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,084,299	$10,084,299
		SUBTOTAL			**$10,084,299**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$408,958	$408,958
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$31,394	$31,394
		SUBTOTAL			**$440,352**
		SITE SUBTOTAL			**$30,270,481**
	CONTINGENGY (15%)				$4,540,572
	Project Total (before scrap credit)				$34,811,053
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($6,449,499)
TOTAL PRICE					**$28,361,555**

TABLE 5.2c
Border Winds Project

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT (Border Winds Project)
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators V100.20	75	EA	$148,490	$11,136,713
1b	Haul Off of Materials (Trucking/Rail)	75	EA	23,596	$1,769,707
1c	Foundation Removal V100.20	75	EA	$70,184	$5,263,779
1d	Crane Mobilization & Demobilization	1	LS	$2,417,050	$2,417,050
		SUBTOTAL			**$20,587,249**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,909,810	$8,909,810
		SUBTOTAL			**$8,909,810**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,933,366	$1,933,366
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$248,574	$248,574
		SUBTOTAL			**$2,181,939**
		SITE SUBTOTAL			**$31,678,997**
	CONTINGENGY (15%)				$4,751,850
	Project Total (before scrap credit)				$36,430,847
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,456,601)
TOTAL PRICE					**$30,974,246**

TABLE 5.2d
Border Winds Project
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT (Border Winds Project (48 in.))
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	75	EA	$154,721	$11,604,079
1b	Haul Off of Materials (Trucking/Rail)	75	EA	19,500	$1,462,533
1c	Foundation Removal - V100-2.0	75	EA	$7,800	$585,008
1d	Crane Mobilization & Demobilization	1	LS	$2,283,888	$2,283,888
		SUBTOTAL			**$15,935,508**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,622,688	$8,622,688
		SUBTOTAL			**$8,622,688**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$397,071	$397,071
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$24,857	$24,857
		SUBTOTAL			**$421,928**
		SITE SUBTOTAL			**$24,980,125**
	CONTINGENGY (15%)				$3,747,019
	Project Total (before scrap credit)				$28,727,143
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($3,681,527)
TOTAL PRICE					**$25,045,616**

TABLE 5.2e
Courtenay Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
					Courtenay
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$135,978	$13,597,829
1b	Haul Off of Materials (Trucking/Rail)	100	EA	25,687	$2,568,667
1c	Foundation Removal - V100-2.0	100	EA	$67,047	$6,704,742
1d	Crane Mobilization & Demobilization	1	LS	$1,954,154	$1,954,154
		SUBTOTAL			**$24,825,391**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$11,048,476	$11,048,476
		SUBTOTAL			**$11,048,476**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,050,705	$2,050,705
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$331,432	$331,432
		SUBTOTAL			**$2,382,137**
		SITE SUBTOTAL			**$38,256,004**
	CONTINGENGY (15%)				$5,738,401
	Project Total (before scrap credit)				$43,994,405
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($7,680,961)
TOTAL PRICE					**$36,313,443**

TABLE 5.2f
Courtenay Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Courtenay (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$139,705	$13,970,467
1b	Haul Off of Materials (Trucking/Rail)	100	EA	21,581	$2,158,116
1c	Foundation Removal - V100-2.0	100	EA	$8,017	$801,686
1d	Crane Mobilization & Demobilization	1	LS	$1,846,356	$1,846,356
		SUBTOTAL			**$18,776,625**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,695,312	$10,695,312
		SUBTOTAL			**$10,695,312**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$407,251	$407,251
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$33,143	$33,143
		SUBTOTAL			**$440,394**
		SITE SUBTOTAL			**$29,912,331**
	CONTINGENGY (15%)				$4,486,850
	Project Total (before scrap credit)				$34,399,181
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,311,810)
TOTAL PRICE					**$29,087,370**

TABLE 5.2g
Foxtail Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	Foxtail AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	7	EA	$141,965	$993,756
	Dismantle Wind Turbine Generators - V120	68	EA	$142,996	$9,723,737
1b	Haul Off of Materials (Trucking/Rail)	75	EA	31,382	$2,353,658
1c	Foundation Removal - V110	7	EA	$66,536	$465,755
	Foundation Removal - V120	68	EA	$66,536	$4,524,475
1d	Crane Mobilization & Demobilization	1	LS	$1,522,963	$1,522,963
		SUBTOTAL			**$19,584,343**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,406,384	$8,406,384
		SUBTOTAL			**$8,406,384**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,609,155	$1,609,155
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$248,574	$248,574
		SUBTOTAL			**$1,857,729**
		SITE SUBTOTAL			**$29,848,456**
	CONTINGENGY (15%)				$4,477,268
	Project Total (before scrap credit)				$34,325,724
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($6,767,995)
TOTAL PRICE					**$27,557,729**

TABLE 5.2h
Foxtail Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Foxtail (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V110	7	EA	$146,429	$1,025,000
	Dismantle Wind Turbine Generators - V120	68	EA	$147,460	$10,027,257
1b	Haul Off of Materials (Trucking/Rail)	75	EA	26,501	$1,987,602
1c	Foundation Removal - V110	7	EA	$7,804	$54,629
	Foundation Removal - V120	68	EA	$7,804	$530,685
1d	Crane Mobilization & Demobilization	1	LS	$1,453,212	$1,453,212
		SUBTOTAL			**$15,078,385**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$8,171,092	$8,171,092
		SUBTOTAL			**$8,171,092**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$324,523	$324,523
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$24,857	$24,857
		SUBTOTAL			**$349,380**
		SITE SUBTOTAL			**$23,598,856**
	CONTINGENGY (15%)				$3,539,828
	Project Total (before scrap credit)				$27,138,685
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($4,850,452)
TOTAL PRICE					**$22,288,232**

TABLE 5.2i
Grand Meadow Wind

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Grand Meadow

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	67	EA	$153,426	$10,279,573
1b	Haul Off of Materials (Trucking/Rail)	67	EA	34,871	$2,336,369
1c	Foundation Removal - GE1.5-77	67	EA	$51,000	$3,416,996
1d	Crane Mobilization & Demobilization	1	LS	$2,201,454	$2,201,454
		SUBTOTAL			**$18,234,392**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$7,490,034	$7,490,034
		SUBTOTAL			**$7,490,034**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,697,809	$1,697,809
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$210,338	$210,338
		SUBTOTAL			**$1,908,147**
		SITE SUBTOTAL			**$27,632,572**
	CONTINGENGY (15%)				$4,144,886
	Project Total (before scrap credit)				$31,777,458
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($6,741,282)
TOTAL PRICE					**$25,036,176**

TABLE 5.2j
Grand Meadow Wind
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

					Grand Meadow (48 in.)
ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	67	EA	$162,780	$10,906,283
1b	Haul Off of Materials (Trucking/Rail)	67	EA	30,931	$2,072,402
1c	Foundation Removal - GE1.5-77	67	EA	$7,838	$525,128
1d	Crane Mobilization & Demobilization	1	LS	$2,138,044	$2,138,044
		SUBTOTAL			**$15,641,858**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$7,343,033	$7,343,033
		SUBTOTAL			**$7,343,033**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$366,382	$366,382
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$21,034	$21,034
		SUBTOTAL			**$387,416**
		SITE SUBTOTAL			**$23,372,307**
	CONTINGENGY (15%)				$3,505,846
	Project Total (before scrap credit)				$26,878,153
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,180,812)
TOTAL PRICE					**$21,697,340**

TABLE 5.2k
Lake Benton II Wind

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Lake Benton II

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE2.1-116	5	EA	$160,812	$804,060
	Dismantle Wind Turbine Generators - GE2.3-116	39	EA	$167,415	$6,529,184
1b	Haul Off of Materials (Trucking/Rail)	44	EA	36,557	$1,608,528
1c	Foundation Removal - GE2.1-116	5	EA	$60,464	$302,318
	Foundation Removal - GE2.3-116	39	EA	$60,464	$2,358,079
1d	Crane Mobilization & Demobilization	1	LS	$1,015,680	$1,015,680
		SUBTOTAL			**$12,617,848**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$4,848,790	$4,848,790
		SUBTOTAL			**$4,848,790**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$1,054,685	$1,054,685
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$138,132	$138,132
		SUBTOTAL			**$1,192,817**
		SITE SUBTOTAL			**$18,659,455**
	CONTINGENGY (15%)				$2,798,918
	Project Total (before scrap credit)				$21,458,374
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($4,628,964)
TOTAL PRICE					**$16,829,410**

TABLE 5.2l
Lake Benton II Wind
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Lake Benton II (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE2.1-116	5	EA	$167,555	$837,777
	Dismantle Wind Turbine Generators - GE2.3-116	39	EA	$174,158	$6,792,178
1b	Haul Off of Materials (Trucking/Rail)	44	EA	31,636	$1,391,969
1c	Foundation Removal - GE2.1-116	5	EA	$7,546	$37,728
	Foundation Removal - GE2.3-116	39	EA	$7,546	$294,280
1d	Crane Mobilization & Demobilization	1	LS	$977,633	$977,633
		SUBTOTAL			$10,331,565
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$4,759,976	$4,759,976
		SUBTOTAL			$4,759,976
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$221,763	$221,763
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$13,813	$13,813
		SUBTOTAL			$235,576
		SITE SUBTOTAL			$15,327,118
	CONTINGENGY (15%)				$2,299,068
	Project Total (before scrap credit)				$17,626,185
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($3,429,286)
TOTAL PRICE					$14,196,899

TABLE 5.2m
Nobles Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT (Nobles)
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	134	EA	$139,113	$18,641,078
1b	Haul Off of Materials (Trucking/Rail)	134	EA	29,979	$4,017,223
1c	Foundation Removal - GE1.5-77	134	EA	$57,739	$7,736,964
1d	Crane Mobilization & Demobilization	1	LS	$1,947,813	$1,947,813
		SUBTOTAL			**$32,343,078**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$13,434,084	$13,434,084
		SUBTOTAL			**$13,434,084**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,399,425	$2,399,425
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$420,675	$420,675
		SUBTOTAL			**$2,820,100**
		SITE SUBTOTAL			**$48,597,262**
	CONTINGENGY (15%)				$7,289,589
	Project Total (before scrap credit)				$55,886,851
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($12,298,196)
TOTAL PRICE					**$43,588,656**

TABLE 5.2n
Nobles Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Nobles (48 in.)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - GE1.5-77	134	EA	$142,885	$19,146,628
1b	Haul Off of Materials (Trucking/Rail)	134	EA	24,922	$3,339,613
1c	Foundation Removal - GE1.5-77	134	EA	$7,559	$1,012,965
1d	Crane Mobilization & Demobilization	1	LS	$1,871,720	$1,871,720
		SUBTOTAL			**$25,370,926**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$13,038,736	$13,038,736
		SUBTOTAL			**$13,038,736**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$479,044	$479,044
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$42,068	$42,068
		SUBTOTAL			**$521,112**
		SITE SUBTOTAL			**$38,930,775**
	CONTINGENGY (15%)				$5,839,616
	Project Total (before scrap credit)				$44,770,391
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($8,815,111)
TOTAL PRICE					**$35,955,280**

TABLE 5.2o
Pleasant Valley Wind Farm

SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

Pleasant Valley

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$159,003	$15,900,269
1b	Haul Off of Materials (Trucking/Rail)	100	EA	27,139	$2,713,931
1c	Foundation Removal - V100-2.0	100	EA	$67,877	$6,787,708
1d	Crane Mobilization & Demobilization	1	LS	$2,150,726	$2,150,726
		SUBTOTAL			**$27,552,633**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,584,412	$10,584,412
		SUBTOTAL			**$10,584,412**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$2,165,432	$2,165,432
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$313,937	$313,937
		SUBTOTAL			**$2,479,368**
		SITE SUBTOTAL			**$40,616,414**
	CONTINGENGY (15%)				$6,092,462
	Project Total (before scrap credit)				$46,708,876
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($7,970,541)
TOTAL PRICE					**$38,738,336**

TABLE 5.2p
Pleasant Valley Wind Farm
(Removal to 48 inches)
SUMMARY OF ACTIVITY COSTS
(2019 Dollars)

ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT Pleasant Valley (48 in.)
1	TURBINE SITE REMOVAL				
1a	Dismantle Wind Turbine Generators - V100-2.0	100	EA	$163,820	$16,381,957
1b	Haul Off of Materials (Trucking/Rail)	100	EA	22,858	$2,285,819
1c	Foundation Removal - V100-2.0	100	EA	$7,923	$792,287
1d	Crane Mobilization & Demobilization	1	LS	$2,061,951	$2,061,951
		SUBTOTAL			**$21,522,014**
2	SITE CIVIL WORK REMOVAL				
2a	Balance of Site Civil Work Removals	1	LS	$10,237,618	$10,237,618
		SUBTOTAL			**$10,237,618**
3	COLLECTION SYSTEM REMOVAL				
3a	Remove MV Collection Cable	1	LS	$438,778	$438,778
3b	Remove Junction Boxes & Turbine Switchgears	1	LS	$31,394	$31,394
		SUBTOTAL			**$470,172**
		SITE SUBTOTAL			**$32,229,804**
	CONTINGENGY (15%)				$4,834,471
	Project Total (before scrap credit)				$37,064,275
	APPROXIMATE SCRAP VALUE OF COMPONENTS				($5,558,899)
TOTAL PRICE					**$31,505,376**

6. REFERENCES

1. E-mail dated November 18, 2019 from Roger P. Schluessel of Xcel Energy to Ben Stochmal at TLG Services; "Labor Rates"
2. E-mail dated December 11, 2019 from Roger P. Schluessel of Xcel Energy to Ben Stochmal at TLG Services; subject "Utility Salaries for 2019"
3. "Building Construction Cost Data 2019," Robert Snow Means Company, Inc., Kingston, Massachusetts [Open]
4. Recycler's World, Iron and Steel Recycling Section and Scrap Copper Recycling Section, U.S. Scrap Metal Index, January 1, 2015 to December 31, 2019 [Open]
5. T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986 [Open]
6. W.J. Manion and T.S. LaGuardia, "Decommissioning Handbook," U.S. Department of Energy, DOE/EV/10128-1, November 1980 [Open]
7. AACE International, Skills and Knowledge of Cost Engineering, 4th Edition, 1999 [Open]
8. 29 CFR Part 1926, Subpart T - Demolition , United States Department of Labor, 2019 https://www.osha.gov/doc/topics/demolition/index.html

APPENDIX A
SUMMARY OF STATION SYSTEM AND STRUCTURES INVENTORIES

TABLE A

SUMMARY OF STATION SYSTEMS AND STRUCTURES INVENTORIES

Index	System/Structure Inventory Data Point	Allen S . King	Angus Anson	Black Dog	Blue Lake	Granite City	Hennepin Island	High Bridge	Inver Hills	Key City	Maplewood	Minnesota Valley	Red Wing	Riverside	Sherburne County	Sibley	Wescott	Wilmarth
Station Rating (Mwe)		511	386	409	545	0	14	606	371	0	0	0	178	502	2238	0	0	18
2	Piping 0.25 to 2 inches diameter, linear foot	79,850	31,521	11,835	20,178	1,501	-	24,690	3,268	1,501	-	492	4,919	24,046	233,790	-	-	4,919
3	Piping >2 to 4 inches diameter, linear foot	53,123	31,014	36,003	13,452	1,001	-	16,460	2,579	1,001	2,195	12,745	3,279	16,031	157,111	2,110	-	3,279
4	Piping >4 to 8 inches diameter, linear foot	35,133	14,009	24,870	10,357	3,138	-	11,173	6,964	3,138	1,120	6,427	2,186	10,687	103,907	520	5,585	2,186
5	Piping >8 to 14 inches diameter, linear foot	30,662	8,006	16,782	6,229	445	-	8,015	1,348	445	330	4,778	1,457	7,125	89,271	385	2,265	1,457
6	Piping >14 to 20 inches diameter, linear foot	7,208	2,614	7,217	4,259	148	-	5,377	1,139	148	90	2,484	794	4,750	26,401	75	20	794
7	Piping >20 to 36 inches diameter, linear foot	9,734	1,886	4,260	2,419	-	-	3,971	-	-	70	1,803	289	3,716	37,053	16	-	289
8	Piping >36 inches diameter, linear foot	5,335	898	3,074	1,796	-	-	2,420	-	-	-	17	173	2,126	15,991	-	60	173
9	Valves <2 inches	1,373	1,308	20	144	108	-	-	216	108	-	54	540	1,418	4,118	-	-	540
10	Valves >2 to 4 inches	935	1,660	1,869	672	72	-	698	174	72	330	402	360	698	2,805	346	-	360
11	Valves >4 to 8 inches	610	592	886	464	80	-	381	264	80	78	207	240	369	1,830	47	104	240
12	Valves >8 to 14 inches	1,519	272	531	142	24	-	159	62	24	44	134	120	123	1,115	54	35	120
13	Valves >14 to 20 inches	158	84	102	48	-	-	78	-	-	2	29	50	66	587	-	4	50
14	Valves >20 to 36 inches	128	22	31	24	-	-	36	-	-	-	14	16	36	476	-	-	16
15	Valves >36 inches	56	6	22	12	-	-	26	-	-	-	1	14	18	104	-	-	14
24	Pipe hangers for small bore piping, each	5,018	3,641	3,225	1,449	81	-	1,742	246	81	88	847	909	1,742	14,975	84	-	909
25	Pipe hangers for large bore piping, each	3,351	1,243	1,672	1,089	121	-	1,249	391	121	64	393	543	1,237	9,618	40	317	543
26	Pump and motor set < 300 pounds	77	17	62	72	16	-	13	108	16	6	32	38	13	507	3	7	38
27	Pumps, 300-1000 pound pump	23	16	18	12	-	-	13	-	-	-	4	8	13	73	-	7	8
28	Pumps, >1000-10,000 pound pump	14	5	15	-	-	-	2	-	-	-	4	11	2	44	-	-	11
29	Pumps, >10,000 pound pump	13	5	14	4	-	-	8	-	-	-	5	8	4	9	-	-	8
32	Pump motors, 300-1000 pound pump	23	32	18	12	-	-	13	-	-	-	4	8	13	28	-	7	8
33	Pump motors, >1000-10,000 pound pump	13	5	12	-	-	-	3	-	-	-	4	11	3	68	2	-	11
34	Pump motors, >10,000 pound pump	13	5	14	4	-	-	8	-	-	-	5	4	4	18	-	-	4
37	Turbine-driven pumps > 10,000 pounds	1	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-
38	Main turbine-generator (pounds per MW(e) input)	1	1	2	-	-	-	1	-	-	-	3	2	2	3	-	-	2
39	Heat exchanger <3000 pound	16	12	30	101	-	-	6	210	-	-	15	12	6	60	-	-	12
40	Heat exchanger >3000 pound	-	27	12	48	-	-	5	96	-	-	7	14	5	21	-	-	14
41	Feedwater heater/deaerator	9	6	25	2	-	-	2	-	-	-	7	12	2	31	-	-	12
49	Main condenser (pounds per MW(e) input)	1	1	2	-	-	-	1	-	-	-	3	2	1	3	-	-	2
51	Tanks, <300 gallons, filters, and ion exchangers	38	33	41	20	16	3	10	34	16	5	39	12	10	66	28	25	12
52	Tanks, 300-3000 gallons	12	32	29	4	12	-	11	8	12	6	7	2	6	132	9	4	2
53	Tanks, >3000 gallons, square foot surface	27,566	75,184	4,933	62,690	2,847	-	23,259	7,069	2,847	101,764	87,790	33,585	1,859	162,458	81,889	374,754	6,871
54	Electrical equipment, <300 pound	742	686	881	647	420	54	150	846	420	21	222	322	128	6,686	36	-	322
55	Electrical equipment, 300-1000 pound	144	296	500	350	40	16	289	184	40	17	51	18	280	936	13	15	18
56	Electrical equipment, 1000-10,000 pound	122	190	203	280	80	25	207	175	80	7	39	56	201	122	2	32	56
57	Electrical equipment, >10,000 pound	19	99	18	128	28	36	16	168	28	5	4	16	16	30	3	5	16
59	Electrical transformers < 30 tons	3	13	22	14	2	-	4	18	2	2	10	-	4	6	2	1	-
60	Electrical transformers > 30 tons	3	9	6	12	2	-	5	12	2	-	4	2	5	3	-	-	2
61	Standby diesel-generator, <100 kW	-	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Standby diesel-generator, 100 kW to 1 MW	-	-	-	-	8	-	-	-	8	-	-	-	-	-	-	-	-
63	Standby diesel-generator, >1 MW	2	-	-	-	4	-	-	-	4	-	-	-	2	5	-	-	-
64	Fluorescent light fixture	200	250	450	180	80	10	200	100	80	30	163	38	150	498	30	24	38
65	Incandescent light fixture	1,564	288	1,000	180	120	16	200	170	120	30	327	258	150	4,060	30	24	258
66	Electrical cable tray, linear foot	27,803	5,512	13,091	5,651	1,730	250	10,276	-	1,730	-	2,107	1,364	9,206	166,291	-	820	1,364
67	Electrical conduit, linear foot	41,992	7,922	45,448	8,631	2,471	4,790	13,688	-	2,471	2,060	18,605	8,658	11,905	119,404	2,000	8,500	8,658
69	Mechanical equipment, <300 pound	788	288	670	52	44	5	31	78	44	8	258	360	21	2,388	6	48	360
70	Mechanical equipment, 300-1000 pound	198	312	290	812	64	8	274	30	64	-	77	14	274	457	21	9	14
71	Mechanical equipment, 1000-10,000 pound	204	60	38	127	-	38	59	1,000	-	3	23	60	44	516	17	28	60
72	Mechanical equipment, >10,000 pound	68	160	106	238	60	26	141	219	60	20	5	45	103	90	8	62	45

TABLE A

SUMMARY OF SYSTEMS AND STRUCTURES INVENTORIES (Continued)

Index	System/Structure Inventory Data Point	Allen S . King	Angus Anson	Black Dog	Blue Lake	Granite City	Hennepin Island	High Bridge	Inver Hills	Key City	Maplewood	Minnesota Valley	Red Wing	Riverside	Sherburne County	Sibley	Wescott	Wilmarth
Station Rating (Mwe)		511	386	409	545	0	14	606	371	0	0	0	178	502	2238	0	0	18
76	HVAC equipment, <300 pound	108	14	-	16	-	-	-	24	-	-	4	10	-	328	-	-	10
77	HVAC equipment, 300-1000 pound	-	22	4	-	-	-	36	-	-	-	-	-	24	107	-	-	-
78	HVAC equipment, 1000-10,000 pound	-	5	-	-	-	-	14	-	-	-	2	4	10	6	-	-	4
79	HVAC equipment, >10,000 pound	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-
82	HVAC ductwork, pound	119,977	10,000	273,680	-	-	8,175	142,100	-	-	-	96,406	18,295	38,202	439,440	-	-	18,295
201	Standard reinforced concrete, cubic yard	24,015	6,662	22,278	14,027	3,806	2,006	18,008	14,800	1,903	770	7,390	9,138	23,366	89,076	591	7,914	5,248
202	Grade slab concrete, cubic yard	10,800	1,329	8,959	1,176	906	-	372	1,384	906	-	676	474	3,551	-	-	-	474
206	Heavily rein concrete w/#9 rebar, cubic yard	7,824	1,110	7,007	-	-	-	-	-	-	-	3,788	1,793	3,035	22,775	-	-	1,793
222	Hollow masonry block wall, cubic yard	-	1,103	374	58	-	-	425	-	-	-	-	-	2,219	-	-	-	109
224	Solid masonry block wall, cubic yard	3,788	-	4,114	-	-	458	-	-	-	-	8,809	663	3,011	14,335	-	-	663
229	Backfill of below grade voids, cubic yard	29,218	11,074	14,043	12,493	2,170	20,000	19,394	6,898	1,308	-	32,816	17,556	12,325	-	-	-	20,531
230	Excavation of clean material, cubic yard	8,747	-	13,387	-	-	-	-	-	-	-	7,307	5,760	18,507	34,560	-	-	5,760
235	Building by volume, cubic foot	5,117,058	229,493	35,076	970,228	189,562	-	318,816	247,411	189,562	159,000	155,740	321,500	597,793	9,863,100	107,000	390,842	321,500
236	Building metal siding, square foot	217,256	42,789	56,780	19,901	37,278	-	108,748	15,564	37,278	-	73,964	32,498	93,913	669,467	-	-	32,498
242	Standard asphalt roofing, square foot	47,897	22,500	32,544	-	-	9,375	110,000	-	-	-	23,588	9,129	119,469	237,266	-	-	9,129
245	Placement of cofferdam, linear foot	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
248	Lead paint removal from concrete surfaces, square foo	373,064	54,000	-	-	-	54,150	-	-	-	-	135,495	54,337	-	-	-	-	54,337
253	Overhead cranes/monorails < 10 ton capacity, each	14	5	2	-	-	-	-	-	-	-	-	1	-	136	-	-	1
255	Overhead cranes/monorails >10 - 50 ton capacity, each	6	2	-	4	-	1	5	-	-	-	2	2	7	21	-	1	2
258	Gantry cranes > 50 ton capacity, each	1	-	-	1	-	-	1	-	-	-	-	-	5	6	-	-	-
260	Structural steel, pounds	24,541,699	2,731,615	13,947,804	1,748,139	310,648	299,854	6,981,323	662,931	310,648	12,000	6,612,141	2,429,526	17,879,987	83,653,565	10,000	77,000	2,429,526
262	Steel floor grating, square foot	161,222	16,242	43,412	7,410	2,673	900	18,797	-	2,673	-	12,083	30,386	56,169	578,353	-	-	30,386
268	Placement of scaffolding in clean areas, square foot	66,680	-	83,881	-	-	-	-	-	-	-	19,777	13,043	-	210,181	-	-	13,043
270	Landscaping with topsoil, acre	3	4	4	1	0	2	1.9	2	0	3	1	4	3	33	2	4	2
271	Landscaping w/o topsoil, acre	29	4	5	8	2	-	4	9	2	3	7	3	8	239	2	4	4
272	Chain link fencing, linear foot	3,372	6,800	3,000	2,880	995	550	3,144	2,800	995	2,460	3,859	8,372	5,016	20,000	3,680	3,450	995
273	Railroad track, linear foot	3,000	-	3,600	-	-	-	-	-	-	-	-	-	-	24,000	-	-	-
274	Asphalt pavement, square foot	220,880	91,000	122,500	78,300	12,000	17,650	75,171	51,000	12,000	17,750	38,225	-	128,241	801,500	45,625	62,700	52,000
293	Carbon steel plate 3/8 inch thick, square foot	-	8,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
294	Carbon steel plate 1/2 inch thick, square foot	66,630	7,388	36,515	14,776	75,398	12,441	14,550	-	75,398	-	6,959	17,695	78,517	219,533	-	-	17,695
359	Steam drum removal (fossil)	1	3	5	6	-	-	6	-	-	-	3	2	9	6	-	-	2
360	Water drum removal (fossil)	-	-	-	-	-	-	-	-	-	-	4	4	-	12	-	-	4
361	Upper/lower waterwall headers (fossil)	26	-	22	-	-	-	-	-	-	-	14	6	27	72	-	-	6
362	Top sup boiler waterwall (8'x8' section), inches cut	138,902	-	75,985	-	-	-	-	-	-	-	45,627	13,392	128,711	470,566	-	-	13,392
369	Boiler convective superheaater platens	307	-	356	-	-	-	-	-	-	-	256	116	459	1,344	-	-	116
370	Boiler radiant superheater platens	-	-	-	-	-	-	-	-	-	-	-	-	-	156	-	-	-
371	Boiler reheat platens	140	-	180	-	-	-	-	-	-	-	-	-	90	666	-	-	-
372	Boiler economizer platens	420	-	169	-	-	-	-	-	-	-	39	-	163	1,344	-	-	-
374	Stationary soot blowers	98	-	64	-	-	-	-	-	-	-	21	-	32	315	-	-	-
375	Retractable soot blowers	70	-	36	-	-	-	-	-	-	-	7	16	18	144	-	-	16
376	Process ductwork (8'x8' section), inches cut	757,268	321,019	1,009,405	625,433	54,416	-	446,315	307,617	54,416	-	470,306	61,481	1,009,280	3,392,767	-	-	61,481
378	Non-asbestos insulated regenerative air preheaters	4	-	9	-	-	-	-	-	-	-	8	8	4	13	-	-	8
380	Non-asbestos insulated recuperative air preheaters	-	-	-	-	-	-	-	-	-	-	4	-	8	-	-	-	-
382	Induced, forced, primary draft fans	9	-	11	-	-	-	-	-	-	-	4	4	-	42	-	-	4
383	Coal car dumpers	1	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-
384	Conveyors	5,528	-	-	-	-	-	-	-	-	-	-	625	-	5,000	-	-	625
385	Transfer Towers	100,500	-	-	-	-	-	-	-	-	-	-	-	-	201,000	-	-	-
386	Stacker-reclaimers	1	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-
389	Ball mills	12	-	8	-	-	-	-	-	-	-	4	-	-	43	-	-	-
390	Coal feeders	120	-	122	-	-	-	-	-	-	-	40	86	-	1,019	-	-	86

TABLE A
SUMMARY OF STATION SYSTEMS AND STRUCTURES INVENTORIES

WIND FARMS ONLY

Index	System/Structure Inventory Data Point	Blazing Star I	Blazing Star I (48 in.)	Border Winds Project	Border Winds Project (48 in.)	Courtenay	Courtenay (48 in.)	Foxtail	Foxtail (48 in.)	Grand Meadow	Grand Meadow (48 in.)	Lake Benton II	Lake Benton II (48 in.)	Nobles	Nobles (48 in.)	Pleasant Valley	Pleasant Valley (48 in.)
Station Rating (Mwe)		200	200	148	148	190	190	150	150	99	99	99	99	197	197	196	196
56	Electrical equipment, 1000-10,000 pound	100	100	75	75	100	100	75	75	67	67	44	44	134	134	100	100
57	Electrical equipment, >10,000 pound	300	300	225	225	300	300	225	225	134	134	132	132	268	268	300	300
67	Electrical conduit, linear foot	1,731,165	-	1,298,374	-	1,731,165	-	1,298,374	-	1,159,881	-	513184	0	2,319,761	-	1,731,165	-
72	Mechanical equipment, >10,000 pound	1,550	1,550	1,163	1,163	1,550	1,550	1,163	1,163	1,039	1,039	770	770	2211	2,211	1650	1650
201	Standard reinforced concrete, cubic yard	36,220	4,067	28,822	3,125	36,182	4,029	28,397	3,086	18,865	2,765	15854	1908	43,432	5,336	38,082	3,997
229	Backfill of below grade voids, cubic yard	207,034	174,881	156,858	131,161	207,034	174,881	156,471	131,161	133,270	117,170	90893	76948	272,437	234,341	208,965	174,881
230	Excavation of clean material, cubic yard	333,101	187,310	249,826	140,483	333,101	187,310	249,826	140,483	223,178	125,498	146565	82416	446,356	250,996	333,101	187,310
235	Building by volume, cubic foot	132,000	132,000	132,000	132,000	108,000	108,000	108,000	108,000	95,625	95,625	102,000	102,000	123,930	123,930.00	88,560	88,560
270	Landscaping with topsoil, acre	71	71	53	53	71	71	53	53	47	47	31	31	95	95	71	71
271	Landscaping w/o topsoil, acre	4	4	3	3	4	4	3	3	3	3	3	3	3	3	3	3
294	Carbon steel plate 1/2 inch thick, square foo	892,716	892,716	588,123	588,123	784,164	784,164	669,644	669,644	658,346	658,346	524316	524316	1,316,693	1,316,692.58	1,156,983	1,156,983

APPENDIX B

UNIT COST FACTOR DEVELOPMENT

APPENDIX B

UNIT COST FACTOR DEVELOPMENT
(Using Minnesota-based labor rates)

Example: Unit Factor for Removal of Heat Exchanger < 3,000 pounds

1. SCOPE

Heat exchangers weighing < 3,000 lb. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the laydown area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration	Critical Duration
a	Remove insulation	20	(b)
b	Mount pipe cutters	60	60
c	Disconnect inlet and outlet lines	60	60
d	Rig for removal	30	30
e	Unbolt from mounts	30	30
f	Remove, send to packing area	60	60
	Totals (Activity/Critical)	260	240

Duration adjustment(s):
+ Work break adjustment (8.33 % of productive duration) 20
Total work duration (minutes) 260

***** Total duration = 4.333 hours *****

3. LABOR REQUIRED

Crew	Number	Duration (hr)	Rate ($/hr)	Cost ($)
Laborers	3.0	4.333	60.80	790.34
Craftsmen	2.0	4.333	71.33	618.15
Foreman	1.0	4.333	73.44	318.22
General Foreman	0.25	4.333	74.44	80.64
Fire Watch	0.05	4.333	60.80	13.17
Total labor cost				1,820.52

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	none
Consumables/Materials Costs	
Gas torch consumables 1 @ $19.93/hr x 1 hr {1}	19.93
Subtotal cost of equipment and materials	19.93
Overhead & profit on equipment and materials @ 16.88%	3.36
Total costs, equipment & material	23.29
TOTAL COST Removal of heat exchanger <3000 pound:	**1,843.81**
Total labor cost:	1,820.52
Total equipment/material costs:	23.29
Total craft labor man-hours required per unit:	27.298

5. NOTES AND REFERENCES

- Durations are shown in minutes. The integrated duration accounts for those activities that can be performed in conjunction with other activities, indicated by the alpha designator of the concurrent activity. This results in an overall decrease in the sequenced duration.

- Work difficulty factors were developed in conjunction with the AIF program to standardize decommissioning cost studies and are delineated in the "Guidelines" study (Reference 2, Vol. 1, Chapter 5).

- References for equipment and consumables costs:

    1. R.S. Means (2019) Division 01 54 33, Section 40-6360 Page 736

APPENDIX C

UNIT COST FACTOR LISTING

TABLE C-1

UNIT COST FACTOR LISTING
Minnesota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors				Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
2	Piping 0.25 to 2 inches diameter, linear foot	6.97	6.89	0.1	-	4	-	0.5	-	-	-	-
3	Piping >2 to 4 inches diameter, linear foot	9.79	9.68	0.2	-	7	-	0.9	-	-	0.4	-
4	Piping >4 to 8 inches diameter, linear foot	18.72	18.56	0.3	-	22	-	-	-	-	-	-
5	Piping >8 to 14 inches diameter, linear foot	36.53	36.34	0.6	-	57	-	-	-	-	-	-
6	Piping >14 to 20 inches diameter, linear foot	47.51	46.93	0.7	-	-	120	-	-	-	-	-
7	Piping >20 to 36 inches diameter, linear foot	69.90	69.13	1.1	-	-	221	-	-	-	-	-
8	Piping >36 inches diameter, linear foot	83.05	82.27	1.3	-	-	417	-	-	-	-	-
9	Valves <2 inches	133.87	133.10	2.0	-	-	-	-	-	-	-	-
10	Valves >2 to 4 inches	124.03	122.86	1.9	75	-	-	8.8	-	-	4.4	-
11	Valves >4 to 8 inches	187.18	185.61	2.8	510	-	-	-	-	-	-	-
12	Valves >8 to 14 inches	365.29	363.36	5.6	1,066	-	-	-	-	-	-	-
13	Valves >14 to 20 inches	475.15	469.33	7.3	-	-	2,040	-	-	-	-	-
14	Valves >20 to 36 inches	699.04	691.28	10.7	-	-	3,334	-	-	-	-	-
15	Valves >36 inches	830.45	822.69	12.7	-	-	11,535	-	-	-	-	-
24	Pipe hangers for small bore piping, each	43.43	37.61	0.6	-	10	-	-	-	-	-	-
25	Pipe hangers for large bore piping, each	156.79	145.14	2.3	-	50	-	-	-	-	-	-
26	Pump and motor set < 300 pounds	316.32	306.61	4.7	-	-	50	12.5	-	-	-	62.3
27	Pumps, 300-1000 pound pump	866.84	851.31	12.7	293	-	49	48.9	-	-	-	-
28	Pumps, >1000-10,000 pound pump	3,438.05	3,414.76	51.3	2,834	-	472	472.3	-	-	-	-
29	Pumps, >10,000 pound pump	6,651.40	6,581.52	98.9	43,693	-	7,282	7,282.1	-	-	-	-
32	Pump motors, 300-1000 pound pump	362.10	362.10	5.4	-	-	-	-	-	-	-	307.8
33	Pump motors, >1000-10,000 pound pump	1,428.02	1,428.02	21.5	-	-	-	-	-	-	-	3,531.6
34	Pump motors, >10,000 pound pump	3,213.05	3,213.05	48.3	-	-	-	-	-	-	-	42,324.5
37	Turbine-driven pumps > 10,000 pounds	8,904.73	8,827.09	132.7	20,000	-	20,000	-	-	-	-	-
38	Main turbine-generator (pounds per MW(e) input)	208,434.81	206,943.98	3,042.0	-	-	851,500	-	-	-	-	851,500.0
39	Heat exchanger <3000 pound	1,843.81	1,820.52	27.3	-	-	416	623.4	-	-	-	-
40	Heat exchanger >3000 pound	4,644.67	4,551.49	68.3	-	-	5,599	8,397.9	-	-	-	-
41	Feedwater heater/deaerator	13,109.71	12,923.36	194.2	-	-	12,000	18,000.0	-	-	-	-
49	Main condenser (pounds per MW(e) input)	573,864.75	553,556.38	8,243.6	149,400	-	149,400	199,200.0	-	-	-	-
51	Tanks, <300 gallons, filters, and ion exchangers	406.82	395.17	6.0	-	-	401	401.2	-	-	-	-
52	Tanks, 300-3000 gallons	1,281.67	1,258.38	19.1	-	-	2,700	300.0	-	-	-	-
53	Tanks, >3000 gallons, square foot surface	10.64	10.35	0.2	-	21	-	-	-	-	-	-
54	Electrical equipment, <300 pound	171.33	171.33	2.6	-	-	56	-	-	-	2.9	-
55	Electrical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	624	-	-	-	32.8	-

TABLE C-1 (continued)

UNIT COST FACTOR LISTING
Minnesota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

Unit Cost Factors					Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
56	Electrical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	2,212	-	-	-	116.4	-
57	Electrical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	19,950	-	-	-	1,050.0	-
59	Electrical transformers < 30 tons	1,930.13	1,930.13	28.4	-	-	11,250	-	-	-	3,750.0	-
60	Electrical transformers > 30 tons	5,558.44	5,558.44	81.9	-	-	375,000	-	-	-	125,000.0	-
61	Standby diesel-generator, <100 kW	1,971.46	1,971.46	29.1	2,340	-	-	-	-	-	-	260.0
62	Standby diesel-generator, 100 kW to 1 MW	4,400.42	4,400.42	64.8	9,450	-	-	-	-	-	-	1,050.0
63	Standby diesel-generator, >1 MW	9,109.78	9,109.78	134.2	47,250	-	-	-	-	-	-	5,250.0
64	Fluorescent light fixture	71.90	71.90	1.1	-	-	-	-	-	-	-	-
65	Incandescent light fixture	36.05	36.05	0.6	-	-	-	-	-	-	-	-
66	Electrical cable tray, linear foot	16.12	15.73	0.2	-	-	-	-	6.6	6.6	-	-
67	Electrical conduit, linear foot	7.04	6.85	0.1	-	-	-	-	3.4	3.4	-	-
69	Mechanical equipment, <300 pound	171.33	171.33	2.6	-	-	127	-	-	-	-	-
70	Mechanical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	641	-	-	-	-	-
71	Mechanical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	4,184	-	-	-	-	-
72	Mechanical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	11,938	-	-	-	-	-
76	HVAC equipment, <300 pound	207.18	207.18	3.1	-	-	184	-	-	-	-	-
77	HVAC equipment, 300-1000 pound	708.37	708.37	10.6	-	-	643	-	-	-	-	-
78	HVAC equipment, 1000-10,000 pound	1,411.80	1,411.80	21.0	-	-	3,813	-	-	-	-	-
79	HVAC equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	19,391	-	-	-	-	-
82	HVAC ductwork, pound	0.68	0.68	0.0	-	-	-	-	1.0	-	-	-
201	Standard reinforced concrete, cubic yard	77.12	26.84	0.4	-	183	-	-	-	-	-	-
202	Grade slab concrete, cubic yard	87.72	30.65	0.5	-	183	-	-	-	-	-	-
206	Heavily rein concrete w/#9 rebar, cubic yard	111.41	39.28	0.6	-	730	-	-	-	-	-	-
222	Hollow masonry block wall, cubic yard	26.45	10.27	0.1	-	66	-	-	-	-	-	-
224	Solid masonry block wall, cubic yard	26.45	10.27	0.1	-	66	-	-	-	-	-	-
229	Backfill of below grade voids, cubic yard	31.11	4.21	0.1	-	-	-	-	-	-	-	-
230	Excavation of clean material, cubic yard	3.23	1.49	0.0	-	-	-	-	-	-	-	-
235	Building by volume, cubic foot	0.34	0.21	-	-	-	1	-	-	-	-	-
236	Building metal siding, square foot	1.74	1.28	0.0	-	-	-	-	2.4	-	-	-
242	Standard asphalt roofing, square foot	3.01	3.01	0.1	-	-	-	-	-	-	-	-
243	Galbestos panels, square foot	2.58	2.06	0.0	-	-	-	-	-	-	-	-
245	Placement of cofferdam, linear foot	-	-	-	-	-	-	-	-	-	-	-

TABLE C-1 (continued)

UNIT COST FACTOR LISTING
Minnesota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

Unit Cost Factors					Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
248	Lead paint removal from concrete surfaces, square foot	10.07	8.11	0.1	-	-	-	-	-	-	-	-
253	Overhead cranes/monorails < 10 ton capacity, each	810.83	810.83	11.8	-	3,700	-	-	-	-	-	-
255	Overhead cranes/monorails >10 - 50 ton capacity, each	1,945.99	1,945.99	28.3	-	-	298,832	-	-	-	3,018.5	-
258	Gantry cranes > 50 ton capacity, each	31,034.60	31,034.60	457.3	-	-	712,800	-	-	-	7,200.0	-
260	Structural steel, pounds	0.24	0.20	-	-	1	-	-	-	-	-	-
262	Steel floor grating, square foot	5.73	5.32	0.1	-	-	6	-	1.1	-	-	-
268	Placement of scaffolding in clean areas, square foot	18.58	6.42	0.1	-	-	-	-	-	-	-	-
270	Landscaping with topsoil, acre	24,287.33	3,567.37	52.6	-	-	-	-	-	-	-	-
271	Landscaping w/o topsoil, acre	1,151.70	380.40	5.3	-	-	-	-	-	-	-	-
272	Chain link fencing, linear foot	4.13	3.47	0.1	-	-	-	-	10.0	-	-	-
273	Railroad track, linear foot	28.23	14.43	0.2	-	91	-	-	-	-	-	-
274	Asphalt pavement, square foot	1.02	0.75	0.0	-	-	-	-	-	-	-	-
291	Carbon steel plate 1/4 inch thick, square foot	4.48	3.80	0.1	-	-	10	-	-	-	-	-
294	Carbon steel plate 1/2 inch thick, square foot	4.73	4.00	0.1	-	-	20	-	-	-	-	-
359	Steam drum removal (fossil)	26,089.30	25,934.00	411.6	-	-	480,000	-	-	-	-	-
360	Water drum removal (fossil)	9,683.73	9,654.62	153.2	-	-	320,000	-	-	-	-	-
361	Upper/lower waterwall headers (fossil)	7,308.10	7,278.99	115.5	-	-	120,000	-	-	-	-	-
362	Top sup boiler waterwall (8'x8' section), inches cut	0.87	0.83	0.0	-	-	11	-	-	-	-	-
369	Boiler convective superheaater platens	2,090.33	1,888.47	29.6	-	-	19,501	-	-	-	-	-
370	Boiler radiant superheater platens	884.30	798.91	12.5	-	-	51,652	-	-	-	-	-
371	Boiler reheat platens	884.30	798.91	12.5	-	-	19,501	-	-	-	-	-
372	Boiler economizer platens	1,125.50	1,016.81	15.9	-	-	11,703	-	-	-	-	-
374	Stationary soot blowers	46.10	46.10	0.7	-	-	500	-	-	-	-	50.0
375	Retractable soot blowers	435.82	435.82	6.8	-	-	11,150	-	-	-	-	100.0
376	Process ductwork (8'x8' section), inches cut	0.43	0.40	0.0	-	-	0	-	-	-	-	-
378	Non-asbestos insulated regenerative air preheaters	13,695.05	11,878.10	188.5	-	-	1,376,000	-	-	-	-	-
380	Non-asbestos insulated recuperative air preheaters	7,571.40	6,435.81	101.6	-	-	1,376,000	-	-	-	-	-
382	Induced, forced, primary draft fans	2,080.55	2,033.96	31.9	-	-	30,000	-	-	-	-	3,531.6
383	Coal car dumpers	18,719.68	15,924.38	249.4	-	-	125,000	-	-	-	-	500.0
384	Conveyors	17.64	16.48	0.3	-	-	820	-	-	-	-	-
385	Transfer Towers	0.31	0.17	-	-	-	5	-	-	-	-	-
386	Stacker-reclaimers	190,631.94	190,631.94	3,008.3	-	-	300,000	-	-	-	-	2,000.0
387	Coal crushers	1,260.40	1,248.75	19.3	-	-	36,000	-	-	-	-	250.0
389	Ball mills	1,816.03	1,816.03	28.1	-	-	360,000	-	-	-	-	7,063.1
390	Coal feeders	457.07	445.42	7.1	-	-	1,194	-	-	-	-	-

TABLE C-2

UNIT COST FACTOR LISTING
North Dakota Stations
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors					Scrap Weight				
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Carbon Steel No. 1	Mixed Scrap	No. 2 Copper	Large Motor	Aluminum
56	Electrical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	2,212	116.4	-	-
57	Electrical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	19,950	-	75,610	-
67	Electrical conduit, linear foot	7.06	6.85	0.1	-	-	0.3	-	1.2
72	Mechanical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	11,938	-	-	-
201	Standard reinforced concrete, cubic yard	82.15	26.84	0.4	183	-	-	-	-
229	Backfill of below grade voids, cubic yard	33.80	4.21	0.1	-	-	-	-	-
230	Excavation of clean material, cubic yard	3.41	1.49	0.02	-	-	-	-	-
235	Building by volume, cubic foot	0.35	0.21	0.003	-	1	-	-	-

TABLE C-3

UNIT COST FACTOR LISTING
South Dakota Station
(Costs are in 2019 dollars/Scrap Weights in pounds)

	Unit Cost Factors				Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
2	Piping 0.25 to 2 inches diameter, linear foot	6.97	6.89	0.1	-	4	-	0.5	-	-	-	-
3	Piping >2 to 4 inches diameter, linear foot	9.79	9.68	0.2	-	7	-	0.9	-	-	0.4	-
4	Piping >4 to 8 inches diameter, linear foot	18.71	18.56	0.3	-	22	-	-	-	-	-	-
5	Piping >8 to 14 inches diameter, linear foot	36.52	36.34	0.6	-	57	-	-	-	-	-	-
6	Piping >14 to 20 inches diameter, linear foot	47.48	46.93	0.7	-	-	120	-	-	-	-	-
7	Piping >20 to 36 inches diameter, linear foot	69.86	69.13	1.1	-	-	221	-	-	-	-	-
8	Piping >36 inches diameter, linear foot	83.00	82.27	1.3	-	-	417	-	-	-	-	-
9	Valves <2 inches	133.82	133.10	2.0	-	-	-	-	-	-	-	-
10	Valves >2 to 4 inches	123.95	122.86	1.9	75	-	-	8.8	-	-	4.4	-
11	Valves >4 to 8 inches	187.08	185.61	2.8	510	-	-	-	-	-	-	-
12	Valves >8 to 14 inches	365.17	363.36	5.6	1,066	-	-	-	-	-	-	-
13	Valves >14 to 20 inches	474.79	469.33	7.3	-	-	2,040	-	-	-	-	-
14	Valves >20 to 36 inches	698.56	691.28	10.7	-	-	3,334	-	-	-	-	-
15	Valves >36 inches	829.97	822.69	12.7	-	-	11,535	-	-	-	-	-
24	Pipe hangers for small bore piping, each	43.07	37.61	0.6	-	10	-	-	-	-	-	-
25	Pipe hangers for large bore piping, each	156.07	145.14	2.3	-	50	-	-	-	-	-	-
26	Pump and motor set < 300 pounds	315.72	306.61	4.7	-	-	50	12.5	-	-	-	62.3
27	Pumps, 300-1000 pound pump	865.89	851.31	12.7	293	-	49	48.9	-	-	-	-
28	Pumps, >1000-10,000 pound pump	3,436.62	3,414.76	51.3	2,834	-	472	472.3	-	-	-	-
29	Pumps, >10,000 pound pump	6,647.09	6,581.52	98.9	43,693	-	7,282	7,282.1	-	-	-	-
32	Pump motors, 300-1000 pound pump	362.10	362.10	5.4	-	-	-	-	-	-	-	307.8
33	Pump motors, >1000-10,000 pound pump	1,428.02	1,428.02	21.5	-	-	-	-	-	-	-	3,531.6
34	Pump motors, >10,000 pound pump	3,213.05	3,213.05	48.3	-	-	-	-	-	-	-	42,324.5
38	Main turbine-generator (pounds per MW(e) input)	208,342.91	206,943.98	3,042.0	-	-	851,500	-	-	-	-	851,500.0
39	Heat exchanger <3000 pound	1,842.38	1,820.52	27.3	-	-	416	623.4	-	-	-	-
40	Heat exchanger >3000 pound	4,638.92	4,551.49	68.3	-	-	5,599	8,397.9	-	-	-	-
41	Feedwater heater/deaerator	13,098.22	12,923.36	194.2	-	-	12,000	18,000.0	-	-	-	-
49	Main condenser (pounds per MW(e) input)	572,617.94	553,556.38	8,243.6	149,400	-	149,400	199,200.0	-	-	-	-
51	Tanks, <300 gallons, filters, and ion exchangers	406.10	395.17	6.0	-	-	401	401.2	-	-	-	-
52	Tanks, 300-3000 gallons	1,280.24	1,258.38	19.1	-	-	2,700	300.0	-	-	-	-
53	Tanks, >3000 gallons, square foot surface	10.63	10.35	0.2	-	21	-	-	-	-	-	-
54	Electrical equipment, <300 pound	171.33	171.33	2.6	-	-	56	-	-	-	2.9	-
55	Electrical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	624	-	-	-	32.8	-
56	Electrical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	2,212	-	-	-	116.4	-
57	Electrical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	19,950	-	-	-	1,050.0	-
59	Electrical transformers < 30 tons	1,930.13	1,930.13	28.4	-	-	11,250	-	-	-	3,750.0	-
60	Electrical transformers > 30 tons	5,558.44	5,558.44	81.9	-	-	375,000	-	-	-	125,000.0	-

TABLE C-3 (continued)

UNIT COST FACTOR LISTING
South Dakota Station
(Costs are in 2019 dollars/Scrap Weights in pounds)

Unit Cost Factors					Scrap Weight							
UCF #	Description	Total Cost	Labor Cost	Labor Hours	Cast Iron	Carbon Steel No. 1	Mixed Scrap	SS-1	Galv. Steel.	Insul Cable	No. 2 Copper	Large Motor
61	Standby diesel-generator, <100 kW	1,971.46	1,971.46	29.1	2,340	-	-	-	-	-	-	260.0
64	Fluorescent light fixture	71.90	71.90	1.1	-	-	-	-	-	-	-	-
65	Incandescent light fixture	36.05	36.05	0.6	-	-	-	-	-	-	-	-
66	Electrical cable tray, linear foot	16.09	15.73	0.2	-	-	-	-	6.6	6.6	-	-
67	Electrical conduit, linear foot	7.03	6.85	0.1	-	-	-	-	3.4	3.4	-	-
69	Mechanical equipment, <300 pound	171.33	171.33	2.6	-	-	127	-	-	-	-	-
70	Mechanical equipment, 300-1000 pound	589.54	589.54	8.8	-	-	641	-	-	-	-	-
71	Mechanical equipment, 1000-10,000 pound	1,179.09	1,179.09	17.6	-	-	4,184	-	-	-	-	-
72	Mechanical equipment, >10,000 pound	2,779.22	2,779.22	41.0	-	-	11,938	-	-	-	-	-
76	HVAC equipment, <300 pound	207.18	207.18	3.1	-	-	184	-	-	-	-	-
77	HVAC equipment, 300-1000 pound	708.37	708.37	10.6	-	-	643	-	-	-	-	-
78	HVAC equipment, 1000-10,000 pound	1,411.80	1,411.80	21.0	-	-	3,813	-	-	-	-	-
82	HVAC ductwork, pound	0.68	0.68	0.0	-	-	-	-	1.0	-	-	-
201	Standard reinforced concrete, cubic yard	74.02	26.84	0.4	-	183	-	-	-	-	-	-
202	Grade slab concrete, cubic yard	84.20	30.65	0.5	-	183	-	-	-	-	-	-
206	Heavily rein concrete w/#9 rebar, cubic yard	106.96	39.28	0.6	-	730	-	-	-	-	-	-
222	Hollow masonry block wall, cubic yard	25.45	10.27	0.1	-	66	-	-	-	-	-	-
229	Backfill of below grade voids, cubic yard	29.45	4.21	0.1	-	-	-	-	-	-	-	-
235	Building by volume, cubic foot	0.33	0.21	-	-	-	1	-	-	-	-	-
236	Building metal siding, square foot	1.71	1.28	0.0	-	-	-	-	2.4	-	-	-
242	Standard asphalt roofing, square foot	3.01	3.01	0.1	-	-	-	-	-	-	-	-
248	Lead paint removal from concrete surfaces, square foot	9.80	7.96	0.1	-	-	-	-	-	-	-	-
253	Overhead cranes/monorails < 10 ton capacity, each	810.83	810.83	11.8	-	3,700	-	-	-	-	-	-
255	Overhead cranes/monorails >10 - 50 ton capacity, each	1,945.99	1,945.99	28.3	-	-	298,832	-	-	-	3,018.5	-
260	Structural steel, pounds	0.23	0.20	-	-	1	-	-	-	-	-	-
262	Steel floor grating, square foot	5.70	5.32	0.1	-	-	6	-	1.1	-	-	-
270	Landscaping with topsoil, acre	23,009.82	3,567.37	52.6	-	-	-	-	-	-	-	-
271	Landscaping w/o topsoil, acre	1,104.15	380.40	5.3	-	-	-	-	-	-	-	-
272	Chain link fencing, linear foot	4.09	3.47	0.1	-	-	-	-	10.0	-	-	-
274	Asphalt pavement, square foot	1.01	0.75	0.0	-	-	-	-	-	-	-	-
293	Carbon steel plate 3/8 inch thick, square foot	4.56	3.90	0.1	-	-	15	-	-	-	-	-
294	Carbon steel plate 1/2 inch thick, square foot	4.68	4.00	0.1	-	-	20	-	-	-	-	-
359	Steam drum removal (fossil)	26,079.72	25,934.00	411.6	-	-	480,000	-	-	-	-	-
376	Process ductwork (8'x8' section), inches cut	0.43	0.40	0.01	-	-	0.03	-	-	-	-	-

Electric Utility
Steam Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Allen S. King					
E311	Structures & Improvements	-9.2	6.0	years	Dec-28
E312	Boiler Plant Equipment	-9.2	6.0	years	Dec-28
E314	Turbogenerator Units	-9.2	6.0	years	Dec-28
E315	Accessory Electric Equipment	-9.2	6.0	years	Dec-28
E316	Miscellaneous Power Plant Equipment	-9.2	6.0	years	Dec-28
Red Wing					
E311	Structures & Improvements	-22.2	5.0	years	Dec-27
E312	Boiler Plant Equipment	-22.2	5.0	years	Dec-27
E314	Turbogenerator Units	-22.2	5.0	years	Dec-27
E315	Accessory Electric Equipment	-22.2	5.0	years	Dec-27
E316	Miscellaneous Power Plant Equipment	-22.2	5.0	years	Dec-27
Sherco Unit 1					
E311	Structures & Improvements	-15.0	4.0	years	Dec-26
E312	Boiler Plant Equipment	-15.0	4.0	years	Dec-26
E314	Turbogenerator Units	-15.0	4.0	years	Dec-26
E315	Accessory Electric Equipment	-15.0	4.0	years	Dec-26
E316	Miscellaneous Power Plant Equipment	-15.0	4.0	years	Dec-26
Sherco Unit 2					
E311	Structures & Improvements	-15.0	4.0	years	Dec-26
E312	Boiler Plant Equipment	-15.0	1.0	years	Dec-23
E314	Turbogenerator Units	-15.0	1.0	years	Dec-23
E315	Accessory Electric Equipment	-15.0	1.0	years	Dec-23
E316	Miscellaneous Power Plant Equipment	-15.0	1.0	years	Dec-23
Sherco Unit 3					
E311	Structures & Improvements	-7.5	8.0	years	Dec-30
E312	Boiler Plant Equipment	-7.5	8.0	years	Dec-30
E314	Turbogenerator Units	-7.5	8.0	years	Dec-30
E315	Accessory Electric Equipment	-7.5	8.0	years	Dec-30
E316	Miscellaneous Power Plant Equipment	-7.5	8.0	years	Dec-30
Wilmarth					
E311	Structures & Improvements	-24.6	5.0	years	Dec-27
E312	Boiler Plant Equipment	-24.6	5.0	years	Dec-27
E314	Turbogenerator Units	-24.6	5.0	years	Dec-27
E315	Accessory Electric Equipment	-24.6	5.0	years	Dec-27
E316	Miscellaneous Power Plant Equipment	-24.6	5.0	years	Dec-27

Electric Utility
Nuclear Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Monticello					
E302	Franchises & Consents	*	7.8	years	Sep-30
E321	Structures & Improvements	*	7.8	years	Sep-30
E322	Reactor Plant Equipment	*	7.8	years	Sep-30
E323	Turbogenerator Units	*	7.8	years	Sep-30
E324	Accessory Electric Equipment	*	7.8	years	Sep-30
E325	Miscellaneous Power Plant Equipment	*	7.8	years	Sep-30
Monticello - Interim Storage Facility					
E321	Structures & Improvements	*	7.8	years	Sep-30
E322	Reactor Plant Equipment	*	7.8	years	Sep-30
Prairie Island Unit 1 & 2					
E302	Franchises & Consents	*	11.3	years	Apr-34
E321	Structures & Improvements	*	11.3	years	Apr-34
E322	Reactor Plant Equipment	*	11.3	years	Apr-34
E323	Turbogenerator Units	*	11.3	years	Apr-34
E324	Accessory Electric Equipment	*	11.3	years	Apr-34
E325	Miscellaneous Power Plant Equipment	*	11.3	years	Apr-34
Prairie Island - Interim Storage Facility					
E321	Structures & Improvements	*	11.3	years	Apr-34
E322	Reactor Plant Equipment	*	11.3	years	Apr-34

* Note: The Nuclear Decommissioning Accrual is set as an amount rather than a net salvage rate. Please see Schedule 10 for further information.

Electric Utility
Hydro Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Hennepin Island					
E302	Franchises & Consents	0.0	11.2	years	Feb-34
E331	Structures & Improvements	-26.5	11.2	years	Feb-34
E332	Reservoirs, Dams & Waterways	-26.5	11.2	years	Feb-34
E333	Water Wheels, Turbines & Generators	-26.5	11.2	years	Feb-34
E334	Accessory Electric Equipment	-26.5	11.2	years	Feb-34
E335	Miscellaneous Power Plant Equipment	-26.5	11.2	years	Feb-34
St. Croix Falls					
E331	Structures & Improvements	-15.0	5.0	years	Dec-27
E332	Reservoirs, Dams & Waterways	-15.0	5.0	years	Dec-27
Upper Dam					
E332	Reservoirs, Dams & Waterways	-26.5	11.2	years	Feb-34
E335	Miscellaneous Power Plant Equipment	-26.5	11.2	years	Feb-34

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Angus C. Anson Unit 2 & 3					
E341	Structures & Improvements	-6.4	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-11.3	18.0	years	Dec-40
E343	Prime Movers	-11.3	18.0	years	Dec-40
E344	Generators	-11.3	18.0	years	Dec-40
E345	Accessory Electric Equipment	-11.3	18.0	years	Dec-40
E346	Miscellaneous Power Plant Equipment	-11.3	18.0	years	Dec-40
Angus C. Anson Unit 4					
E341	Structures & Improvements	-6.4	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-6.4	22.4	years	May-45
E343	Prime Movers	-6.4	22.4	years	May-45
E344	Generators	-6.4	22.4	years	May-45
E345	Accessory Electric Equipment	-6.4	22.4	years	May-45
E346	Miscellaneous Power Plant Equipment	-6.4	22.4	years	May-45
Black Dog Unit 5					
E341	Structures & Improvements	-10.2	35.3	years	Mar-58
E342	Fuel Holders, Producers & Accessories	-7.2	9.0	years	Dec-31
E343	Prime Movers	-7.2	9.0	years	Dec-31
E344	Generators	-7.2	9.0	years	Dec-31
E345	Accessory Electric Equipment	-7.2	9.0	years	Dec-31
E346	Miscellaneous Power Plant Equipment	-7.2	9.0	years	Dec-31
Black Dog Unit 6					
E341	Structures & Improvements	-10.2	35.3	years	Mar-58
E342	Fuel Holders, Producers & Accessories	-10.2	35.3	years	Mar-58
E343	Prime Movers	-10.2	35.3	years	Mar-58
E344	Generators	-10.2	35.3	years	Mar-58
E345	Accessory Electric Equipment	-10.2	35.3	years	Mar-58
E346	Miscellaneous Power Plant Equipment	-10.2	35.3	years	Mar-58
Blazing Star I Wind					
E340.1	Wind Rights	0.0	22.3	years	Apr-45
E341	Structures & Improvements	-11.3	22.3	years	Apr-45
E342	Fuel Holders, Producers & Accessories	-11.3	22.3	years	Apr-45
E343	Prime Movers	-11.3	22.3	years	Apr-45
E344	Generators	-11.3	22.3	years	Apr-45
E345	Accessory Electric Equipment	-11.3	22.3	years	Apr-45
E346	Miscellaneous Power Plant Equipment	-11.3	22.3	years	Apr-45
Blazing Star II Wind					
E340.1	Wind Rights	0.0	23.1	years	Jan-46
E341	Structures & Improvements	-10.4	23.1	years	Jan-46
E342	Fuel Holders, Producers & Accessories	-10.4	23.1	years	Jan-46
E343	Prime Movers	-10.4	23.1	years	Jan-46
E344	Generators	-10.4	23.1	years	Jan-46
E345	Accessory Electric Equipment	-10.4	23.1	years	Jan-46
E346	Miscellaneous Power Plant Equipment	-10.4	23.1	years	Jan-46

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Blue Lake Units 1 thru 4					
E341	Structures & Improvements	-11.6	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-28.6	0.5	years	Jun-23
E343	Prime Movers	-28.6	0.5	years	Jun-23
E344	Generators	-28.6	0.5	years	Jun-23
E345	Accessory Electric Equipment	-28.6	0.5	years	Jun-23
E346	Miscellaneous Power Plant Equipment	-28.6	0.5	years	Jun-23
Blue Lake Units 7 & 8					
E341	Structures & Improvements	-11.6	22.4	years	May-45
E342	Fuel Holders, Producers & Accessories	-11.6	22.4	years	May-45
E343	Prime Movers	-11.6	22.4	years	May-45
E344	Generators	-11.6	22.4	years	May-45
E345	Accessory Electric Equipment	-11.6	22.4	years	May-45
E346	Miscellaneous Power Plant Equipment	-11.6	22.4	years	May-45
Border Winds					
E340.1	Wind Rights	0.0	27.0	years	Dec-49
E341	Structures & Improvements	-9.5	27.0	years	Dec-49
E342	Fuel Holders, Producers & Accessories	-9.5	27.0	years	Dec-49
E343	Prime Movers	-9.5	27.0	years	Dec-49
E344	Generators	-9.5	27.0	years	Dec-49
E345	Accessory Electric Equipment	-9.5	27.0	years	Dec-49
E346	Miscellaneous Power Plant Equipment	-9.5	27.0	years	Dec-49
Community Wind North					
E340.1	Wind Rights	0.0	23.0	years	Dec-45
E341	Structures & Improvements	-10.4	23.0	years	Dec-45
E342	Fuel Holders, Producers & Accessories	-10.4	23.0	years	Dec-45
E343	Prime Movers	-10.4	23.0	years	Dec-45
E344	Generators	-10.4	23.0	years	Dec-45
E345	Accessory Electric Equipment	-10.4	23.0	years	Dec-45
E346	Miscellaneous Power Plant Equipment	-10.4	23.0	years	Dec-45
Courtenay Wind					
E340.1	Wind Rights	0.0	18.9	years	Nov-41
E341	Structures & Improvements	-10.3	18.9	years	Nov-41
E342	Fuel Holders, Producers & Accessories	-10.3	18.9	years	Nov-41
E343	Prime Movers	-10.3	18.9	years	Nov-41
E344	Generators	-10.3	18.9	years	Nov-41
E345	Accessory Electric Equipment	-10.3	18.9	years	Nov-41
E346	Miscellaneous Power Plant Equipment	-10.3	18.9	years	Nov-41
Crowned Ridge Wind					
E340.1	Wind Rights	0.0	23.0	years	Dec-45
E341	Structures & Improvements	-10.4	23.0	years	Dec-45
E342	Fuel Holders, Producers & Accessories	-10.4	23.0	years	Dec-45
E343	Prime Movers	-10.4	23.0	years	Dec-45
E344	Generators	-10.4	23.0	years	Dec-45
E345	Accessory Electric Equipment	-10.4	23.0	years	Dec-45
E346	Miscellaneous Power Plant Equipment	-10.4	23.0	years	Dec-45

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Dakota Range Wind					
E340.1	Wind Rights	0.0	24.1	years	Jan-47
E341	Structures & Improvements	-10.4	24.1	years	Jan-47
E342	Fuel Holders, Producers & Accessories	-10.4	24.1	years	Jan-47
E343	Prime Movers	-10.4	24.1	years	Jan-47
E344	Generators	-10.4	24.1	years	Jan-47
E345	Accessory Electric Equipment	-10.4	24.1	years	Jan-47
E346	Miscellaneous Power Plant Equipment	-10.4	24.1	years	Jan-47
Foxtail Wind					
E340.1	Wind Rights	0.0	22.0	years	Dec-44
E341	Structures & Improvements	-9.4	22.0	years	Dec-44
E342	Fuel Holders, Producers & Accessories	-9.4	22.0	years	Dec-44
E343	Prime Movers	-9.4	22.0	years	Dec-44
E344	Generators	-9.4	22.0	years	Dec-44
E345	Accessory Electric Equipment	-9.4	22.0	years	Dec-44
E346	Miscellaneous Power Plant Equipment	-9.4	22.0	years	Dec-44
Freeborn Wind					
E340.1	Wind Rights	0.0	23.4	years	May-46
E341	Structures & Improvements	-10.4	23.4	years	May-46
E342	Fuel Holders, Producers & Accessories	-10.4	23.4	years	May-46
E343	Prime Movers	-10.4	23.4	years	May-46
E344	Generators	-10.4	23.4	years	May-46
E345	Accessory Electric Equipment	-10.4	23.4	years	May-46
E346	Miscellaneous Power Plant Equipment	-10.4	23.4	years	May-46
Grand Meadow Wind					
E340.1	Wind Rights	0.0	20.9	years	Nov-43
E341	Structures & Improvements	-12.4	20.9	years	Nov-43
E342	Fuel Holders, Producers & Accessories	-12.4	20.9	years	Nov-43
E343	Prime Movers	-12.4	20.9	years	Nov-43
E344	Generators	-12.4	20.9	years	Nov-43
E345	Accessory Electric Equipment	-12.4	20.9	years	Nov-43
E346	Miscellaneous Power Plant Equipment	-12.4	20.9	years	Nov-43
High Bridge					
E341	Structures & Improvements	-4.2	25.4	years	May-48
E342	Fuel Holders, Producers & Accessories	-4.2	25.4	years	May-48
E343	Prime Movers	-4.2	25.4	years	May-48
E344	Generators	-4.2	25.4	years	May-48
E345	Accessory Electric Equipment	-4.2	25.4	years	May-48
E346	Miscellaneous Power Plant Equipment	-4.2	25.4	years	May-48
Inver Hills					
E341	Structures & Improvements	-20.3	4.0	years	Dec-26
E342	Fuel Holders, Producers & Accessories	-20.3	4.0	years	Dec-26
E343	Prime Movers	-20.3	4.0	years	Dec-26
E344	Generators	-20.3	4.0	years	Dec-26
E345	Accessory Electric Equipment	-20.3	4.0	years	Dec-26
E346	Miscellaneous Power Plant Equipment	-20.3	4.0	years	Dec-26

Electric Utility
Other Production

Account	Description	Net Salvage (%)	Remaining Life 01/01/2023		Retirement date
Jeffers Wind					
E340.1	Wind Rights	0.0	23.0	years	Dec-45
E341	Structures & Improvements	-10.4	23.0	years	Dec-45
E342	Fuel Holders, Producers & Accessories	-10.4	23.0	years	Dec-45
E343	Prime Movers	-10.4	23.0	years	Dec-45
E344	Generators	-10.4	23.0	years	Dec-45
E345	Accessory Electric Equipment	-10.4	23.0	years	Dec-45
E346	Miscellaneous Power Plant Equipment	-10.4	23.0	years	Dec-45
Lake Benton II Wind					
E340.1	Wind Rights	0.0	21.9	years	Nov-44
E341	Structures & Improvements	-10.5	21.9	years	Nov-44
E342	Fuel Holders, Producers & Accessories	-10.5	21.9	years	Nov-44
E343	Prime Movers	-10.5	21.9	years	Nov-44
E344	Generators	-10.5	21.9	years	Nov-44
E345	Accessory Electric Equipment	-10.5	21.9	years	Nov-44
E346	Miscellaneous Power Plant Equipment	-10.5	21.9	years	Nov-44
Mower Wind					
E340.1	Wind Rights	0.0	23.3	years	Mar-46
E341	Structures & Improvements	-10.4	23.3	years	Mar-46
E342	Fuel Holders, Producers & Accessories	-10.4	23.3	years	Mar-46
E343	Prime Movers	-10.4	23.3	years	Mar-46
E344	Generators	-10.4	23.3	years	Mar-46
E345	Accessory Electric Equipment	-10.4	23.3	years	Mar-46
E346	Miscellaneous Power Plant Equipment	-10.4	23.3	years	Mar-46
Nobles Wind					
E340.1	Wind Rights	0.0	22.9	years	Nov-45
E341	Structures & Improvements	-8.5	22.9	years	Nov-45
E342	Fuel Holders, Producers & Accessories	-8.5	22.9	years	Nov-45
E343	Prime Movers	-8.5	22.9	years	Nov-45
E344	Generators	-8.5	22.9	years	Nov-45
E345	Accessory Electric Equipment	-8.5	22.9	years	Nov-45
E346	Miscellaneous Power Plant Equipment	-8.5	22.9	years	Nov-45
Pleasant Valley Wind					
E340.1	Wind Rights	0.0	27.0	years	Dec-49
E341	Structures & Improvements	-11.7	27.0	years	Dec-49
E342	Fuel Holders, Producers & Accessories	-11.7	27.0	years	Dec-49
E343	Prime Movers	-11.7	27.0	years	Dec-49
E344	Generators	-11.7	27.0	years	Dec-49
E345	Accessory Electric Equipment	-11.7	27.0	years	Dec-49
E346	Miscellaneous Power Plant Equipment	-11.7	27.0	years	Dec-49
Riverside					
E341	Structures & Improvements	-12.2	26.2	years	Feb-49
E342	Fuel Holders, Producers & Accessories	-12.2	26.2	years	Feb-49
E343	Prime Movers	-12.2	26.2	years	Feb-49
E344	Generators	-12.2	26.2	years	Feb-49
E345	Accessory Electric Equipment	-12.2	26.2	years	Feb-49
E346	Miscellaneous Power Plant Equipment	-12.2	26.2	years	Feb-49
Wind-to-Battery System					
E348.1	Energy Storage Equipment	-135.6	0.0	years	Jan-21

Electric Utility
Other Production (on acquisition dockets as approved by the Commission)

Account	Description	Proposed Net Salvage (%)	Proposed Remaining Life as of Estimated Acquisition Date		Retirement date
Northern Wind					
E340.1	Wind Rights	0.0	25.0	years***	***
E341	Structures & Improvements	-10.4	25.0	years***	***
E342	Fuel Holders, Producers & Accessories	-10.4	25.0	years***	***
E343	Prime Movers	-10.4	25.0	years***	***
E344	Generators	-10.4	25.0	years***	***
E345	Accessory Electric Equipment	-10.4	25.0	years***	***
E346	Miscellaneous Power Plant Equipment	-10.4	25.0	years***	***

Account	Description	Proposed Net Salvage (%)	Proposed Remaining Life as of Estimated Acquisition Date		Retirement date
Rock Aetna Wind					
E340.1	Wind Rights	0.0	25.0	years***	***
E341	Structures & Improvements	-10.4	25.0	years***	***
E342	Fuel Holders, Producers & Accessories	-10.4	25.0	years***	***
E343	Prime Movers	-10.4	25.0	years***	***
E344	Generators	-10.4	25.0	years***	***
E345	Accessory Electric Equipment	-10.4	25.0	years***	***
E346	Miscellaneous Power Plant Equipment	-10.4	25.0	years***	***

***Estimated acquisition dates are December 2022 for Northern Wind and January 2023 for Rock Aetna.

				Present		Proposed		
	FERC Account	Plant Balance 1/1/2022		Net Salv %	Estimated Net Salvage in Reserve at End of Life	Net Salv %	Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)		(2)	(3)	(4)	(5)	(6)
Allen S. King								
	E311	$ 39,721,551	D	-5.5	$ 2,184,685	-9.2	$ 3,653,575	$ 1,468,889
	E312	$ 525,951,646	D	-5.5	$ 28,927,341	-9.2	$ 48,376,852	$ 19,449,512
	E314	$ 94,307,445	D	-5.5	$ 5,186,909	-9.2	$ 8,674,366	$ 3,487,457
	E315	$ 46,921,220	D	-5.5	$ 2,580,667	-9.2	$ 4,315,798	$ 1,735,131
	E316	$ 7,979,927	D	-5.5	$ 438,896	-9.2	$ 733,991	$ 295,095
		$ 714,881,790			$ 39,318,498		$ 65,754,582	$ 26,436,084
					From 2019 Dismantling Study for King	-9.2%	$ 65,754,582	
Red Wing								
	E311	$ 12,856,986	D	-23.3	$ 2,995,678	-22.1	$ 2,847,819	$ (147,859)
	E312	$ 47,840,342	D	-23.3	$ 11,146,800	-22.1	$ 10,596,623	$ (550,177)
	E314	$ 6,111,636	D	-23.3	$ 1,424,011	-22.1	$ 1,353,726	$ (70,285)
	E315	$ 1,905,550	D	-23.3	$ 443,993	-22.1	$ 422,079	$ (21,914)
	E316	$ 1,484,962	D	-23.3	$ 345,996	-22.1	$ 328,919	$ (17,077)
		$ 70,199,477			$ 16,356,478		$ 15,549,165	$ (807,313)
					From 2019 Dismantling Study for Red Wing	-22.1%	$ 15,549,165	
Sherco Units 1 & 2								
	E311	$ 96,365,770	D	-5.1	$ 4,914,654	-15.0	$ 14,480,678	$ 9,566,024
	E312	$ 436,999,604	D	-5.1	$ 22,286,980	-15.0	$ 65,666,996	$ 43,380,016
	E314	$ 124,993,581	D	-5.1	$ 6,374,673	-15.0	$ 18,782,518	$ 12,407,846
	E315	$ 54,081,011	D	-5.1	$ 2,758,132	-15.0	$ 8,126,638	$ 5,368,506
	E316	$ 12,378,693	D	-5.1	$ 631,313	-15.0	$ 1,860,120	$ 1,228,806
		$ 724,818,659			$ 36,965,752		$ 108,916,950	$ 71,951,199
					From 2019 Dismantling Study for Sherco 1 & 2	-15.0%	$ 108,916,950	
Sherco Unit 3 (*)								
	E311	$ 133,482,187	D	-4.3	$ 5,739,734	-7.5	$ 9,973,311	$ 4,233,577
	E312	$ 457,428,065	D	-4.3	$ 19,669,407	-7.5	$ 34,177,388	$ 14,507,981
	E314	$ 90,332,472	D	-4.3	$ 3,884,296	-7.5	$ 6,749,319	$ 2,865,023
	E315	$ 83,085,559	D	-4.3	$ 3,572,679	-7.5	$ 6,207,856	$ 2,635,177
	E316	$ 31,193,847	D	-4.3	$ 1,341,335	-7.5	$ 2,330,693	$ 989,357
		$ 795,522,130			$ 34,207,452		$ 59,438,567	$ 25,231,115
					From 2019 Dismantling Study for Sherco 3	-7.5%	$ 59,438,567	
Wilmarth								
	E311	$ 11,645,698	D	-23.0	$ 2,678,511	-24.6	$ 2,867,492	$ 188,982
	E312	$ 44,393,918	D	-23.0	$ 10,210,601	-24.6	$ 10,931,008	$ 720,407
	E314	$ 6,175,415	D	-23.0	$ 1,420,345	-24.6	$ 1,520,558	$ 100,212
	E315	$ 1,551,512	D	-23.0	$ 356,848	-24.6	$ 382,025	$ 25,177
	E316	$ 821,824	D	-23.0	$ 189,020	-24.6	$ 202,356	$ 13,336
		$ 64,588,367			$ 14,855,324		$ 15,903,439	$ 1,048,115
					From 2019 Dismantling Study for Wilmarth	-24.6%	$ 15,903,439	
Total Steam Production		$ 2,370,010,422			$ 141,703,504		$ 265,562,703	$ 123,859,199

* Amounts reported in this section are for the entire unit, not just Xcel Energy's share.

	FERC Account	Plant Balance 1/1/2022		Present: Net Salv %	Present: Estimated Net Salvage in Reserve at End of Life	Proposed: Net Salv %	Proposed: Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)		(2)	(3)	(4)	(5)	(6)
Hennepin Island								
	E302	$ 2,857,039	D	0.0	$ -	0.0	$ -	$ -
	E331	$ 1,429,599	D	-30.0	$ 428,880	-26.5	$ 378,890	$ (49,989)
	E332	$ 4,398,484	D	-30.0	$ 1,319,545	-26.5	$ 1,165,742	$ (153,803)
	E333	$ 10,156,575	D	-30.0	$ 3,046,973	-26.5	$ 2,691,825	$ (355,148)
	E334	$ 3,279,241	D	-30.0	$ 983,772	-26.5	$ 869,106	$ (114,666)
	E335	$ 37,779	D	-30.0	$ 11,334	-26.5	$ 10,013	$ (1,321)
	E336	$ 152,075	D	-30.0	$ 45,623	-26.5	$ 40,305	$ (5,318)
		$ 22,310,791			$ 5,836,126		$ 5,155,881	$ (680,245)
		From 2019 Dismantling Study for Hennepin Island				-26.5%	$ 5,155,881	
						Note 1	Note 2	
St. Croix Falls								
	E331	$ 37,924	D	-7.5	$ 2,844	-15.0	$ 5,689	$ 2,844
	E332	$ 2,196,276	D	-7.5	$ 164,721	-15.0	$ 329,441	$ 164,721
		$ 2,234,201			$ 167,565		$ 335,130	$ 167,565
					St. Croix Falls	-15.0%	$ 335,130	
					Note 3			
Upper Dam								
	E332	$ 4,491,476	D	-30.0	$ 1,347,443	-26.5	$ 1,190,388	$ (157,055)
	E335	$ 23,046	D	-30.0	$ 6,914	-26.5	$ 6,108	$ (806)
		$ 4,514,522			$ 1,354,357		$ 1,196,496	$ (157,861)
		From 2019 Dismantling Study for Upper Dam				-26.5%	$ 1,196,496	
							Note 2	
Total Hydro Production		$ 29,059,513			$ 7,358,047		$ 6,687,507	$ (670,540)

Note 1: To calculate the proposed net salvage percent, FERC 302 Licenses was excluded from the plant balance as removal costs do not apply to this account.
Note 2: The dismantling costs for the Upper Dam are not separately stated in the TLG Dismantling Report. Therefore, the $6.4M TLG estimate is allocated based on plant balance to each portion in order to calculate the net salvage percent.
Note 3: St. Croix Falls is mainly located in Wisconsin but a portion of the facility is in Minnesota. The balances above represent the assets included on NSP-Minnesota's records. This facility was not included in the TLG Dismantling Study. Therefore, we are using the net salvage rate for FERC 332 approved by the Public Service Commission of Wisconsin.

	FERC Account	Plant Balance 1/1/2022		Present: Net Salv %	Present: Estimated Net Salvage in Reserve at End of Life	Proposed: Net Salv %	Proposed: Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)		(2)	(3)	(4)	(5)	(6)
Angus C. Anson Units 2 & 3								
	E341	$ -	D	-4.5	$ -	-11.3	$ -	$ -
	E342	$ 1,070,423	D	-4.5	$ 48,169	-11.3	$ 120,621	$ 72,452
	E344	$ 77,661,605	D	-4.5	$ 3,494,772	-11.3	$ 8,751,327	$ 5,256,555
	E345	$ 4,876,179	D	-4.5	$ 219,428	-11.3	$ 549,474	$ 330,046
	E346	$ 2,631,260	D	-4.5	$ 118,407	-11.3	$ 296,505	$ 178,098
		$ 86,239,468			$ 3,880,776		$ 9,717,926	$ 5,837,150
	From 2019 Dismantling Study for Angus Anson Units 2 & 3					-11.3%	$ 9,717,926	
Angus C. Anson Unit 4								
	E341	$ 8,235,254	D	-4.5	$ 370,586	-6.4	$ 527,268	$ 156,682
	E342	$ 13,506	D	-4.5	$ 608	-6.4	$ 865	$ 257
	E344	$ 33,793,801	D	-4.5	$ 1,520,721	-6.4	$ 2,163,673	$ 642,952
	E345	$ 4,930,962	D	-4.5	$ 221,893	-6.4	$ 315,708	$ 93,815
	E346	$ 20,727	D	-4.5	$ 933	-6.4	$ 1,327	$ 394
		$ 46,994,250			$ 2,114,741		$ 3,008,842	$ 894,100
	From 2019 Dismantling Study for Angus Anson 4					-6.4%	$ 3,008,842	
Black Dog Unit 5								
	E342	$ 12,539,031	D	-1.7	$ 213,164	-7.2	$ 905,477	$ 692,313
	E343	$ 24,220,121	D	-1.7	$ 411,742	-7.2	$ 1,748,999	$ 1,337,257
	E344	$ 125,367,218	D	-1.7	$ 2,131,243	-7.2	$ 9,053,100	$ 6,921,857
	E345	$ 28,111,443	D	-1.7	$ 477,895	-7.2	$ 2,030,002	$ 1,552,107
	E346	$ 5,657,756	D	-1.7	$ 96,182	-7.2	$ 408,562	$ 312,380
		$ 195,895,570			$ 3,330,225		$ 14,146,139	$ 10,815,914
	From 2019 Dismantling Study for Black Dog Unit 5					-7.2%	$ 14,146,139 Note 1	
Black Dog Unit 6								
	E341	$ 43,411,128	D	-1.7	$ 737,989	-10.2	$ 4,449,194	$ 3,711,205
	E341	$ 13,825,936	D	-5.0	$ 691,297	-10.2	$ 1,417,016	$ 725,720
	E342	$ 9,512,175	D	-5.0	$ 475,609	-10.2	$ 974,900	$ 499,291
	E344	$ 62,375,841	D	-5.0	$ 3,118,792	-10.2	$ 6,392,883	$ 3,274,091
	E345	$ 11,141,445	D	-5.0	$ 557,072	-10.2	$ 1,141,884	$ 584,811
	E346	$ 5,817,664	D	-5.0	$ 290,883	-10.2	$ 596,251	$ 305,368
		$ 146,084,190			$ 5,871,642		$ 14,972,128	$ 9,100,486
	From 2019 Dismantling Study for Black Dog Unit 6					-10.2%	$ 14,972,128 Note 1	
Blazing Star I								
	E340	$ -	D	0.0	$ -	0.0	$ -	$ -
	E341	$ 22,712,370	D	-8.5	$ 1,930,551	-11.3	$ 2,568,828	$ 638,276
	E342	$ -	D	-8.5	$ -	-11.3	$ -	$ -
	E344	$ 274,310,899	D	-8.5	$ 23,316,426	-11.3	$ 31,025,271	$ 7,708,845
	E345	$ 10,359,276	D	-8.5	$ 880,538	-11.3	$ 1,171,661	$ 291,122
	E346	$ -	D	-8.5	$ -	-11.3	$ -	$ -
		$ 307,382,545			$ 26,127,516		$ 34,765,760	$ 8,638,244
	From 2019 Dismantling Study for Blazing Star I					-11.3% Note 2	$ 34,765,760	
Blue Lake Units 1 thru 4								
	E341	$ -	D	-5.2	$ -	-28.6	$ -	$ -
	E342	$ 1,340,395	D	-11.9	$ 159,507	-28.6	$ 382,737	$ 223,230
	E344	$ 21,359,097	D	-11.9	$ 2,541,733	-28.6	$ 6,098,888	$ 3,557,156
	E345	$ 2,726,341	D	-11.9	$ 324,435	-28.6	$ 778,481	$ 454,046
	E346	$ 886,743	D	-11.9	$ 105,522	-28.6	$ 253,201	$ 147,679
		$ 26,312,577			$ 3,131,197		$ 7,513,308	$ 4,382,111
	From 2019 Dismantling Study for Blue Lake Units 1 thru 4					-28.6%	$ 7,513,308	

			Present		Proposed		
	FERC Account	Plant Balance 1/1/2022	Net Salv %	Estimated Net Salvage in Reserve at End of Life	Net Salv %	Estimated Net Salvage in Reserve at End of Life	Proposed Less Present
		(1)	(2)	(3)	(4)	(5)	(6)
Blue Lake Units 7 & 8							
	E341	$ 1,703,454 D	-5.2	$ 88,580	-11.6	$ 197,718	$ 109,139
	E342	$ 47,986 D	-5.2	$ 2,495	-11.6	$ 5,570	$ 3,074
	E344	$ 69,105,883 D	-5.2	$ 3,593,506	-11.6	$ 8,021,048	$ 4,427,543
	E345	$ 8,007,188 D	-5.2	$ 416,374	-11.6	$ 929,386	$ 513,012
	E346	$ 32,958 D	-5.2	$ 1,714	-11.6	$ 3,825	$ 2,112
		$ 78,897,469		$ 4,102,668		$ 9,157,548	$ 5,054,879
		From 2019 Dismantling Study for Blue Lake 7 & 8			-11.6%	$ 9,157,548	
Border Winds							
	E340	$ - D	0.0	$ -	0.0	$ -	$ -
	E341	$ 22,226,432 D	-6.6	$ 1,466,944	-9.5	$ 2,101,198	$ 634,254
	E342	$ - D	-6.6	$ -	-9.5	$ -	$ -
	E344	$ 207,682,752 D	-6.6	$ 13,707,062	-9.5	$ 19,633,501	$ 5,926,440
	E345	$ 34,794,649 D	-6.6	$ 2,296,447	-9.5	$ 3,289,348	$ 992,901
	E346	$ 228,153 D	-6.6	$ 15,058	-9.5	$ 21,569	$ 6,511
		$ 264,931,986		$ 17,485,511		$ 25,045,616	$ 7,560,105
		From 2019 Dismantling Study for Border Winds			-9.5% Notes 2 & 3	$ 25,045,616	
Courtenay Wind							
	E340	$ 2,085,661 D	0.0	$ -	0.0	$ -	$ -
	E341	$ 7,621,664 D	-6.9	$ 525,895	-10.3	$ 786,869	$ 260,974
	E342	$ - D	-6.9	$ -	-10.3	$ -	$ -
	E344	$ 264,043,707 D	-6.9	$ 18,219,016	-10.3	$ 27,260,161	$ 9,041,145
	E345	$ 10,040,328 D	-6.9	$ 692,783	-10.3	$ 1,036,574	$ 343,792
	E346	$ 36,482 D	-6.9	$ 2,517	-10.3	$ 3,766	$ 1,249
		$ 283,827,841		$ 19,440,210		$ 29,087,370	$ 9,647,160
		From 2019 Dismantling Study for Courtenay			-10.3% Notes 2 & 3	$ 29,087,370	
Foxtail Wind							
	E340	$ 177,364 D	0.0	$ -	0.0	$ -	$ -
	E341	$ 32,726,023 D	-6.4	$ 2,094,465	-9.4	$ 3,080,110	$ 985,644
	E344	$ 204,085,404 D	-6.4	$ 13,061,466	-9.4	$ 19,208,123	$ 6,146,657
		$ 236,988,791		$ 15,155,931		$ 22,288,232	$ 7,132,301
		From 2019 Dismantling Study for Foxtail			-9.4% Note 3	$ 22,288,232	
Grand Meadow Wind							
	E340	$ 10,672,452 D	0.0	$ -	0.0	$ -	$ -
	E341	$ 5,589,344 D	-8.7	$ 486,273	-12.4	$ 694,240	$ 207,967
	E342	$ - D	-8.7	$ -	-12.4	$ -	$ -
	E344	$ 183,695,056 D	-8.7	$ 15,981,470	-12.4	$ 22,816,353	$ 6,834,883
	E345	$ 12,073,394 D	-8.7	$ 1,050,385	-12.4	$ 1,499,609	$ 449,224
	E346	$ 209,119 D	-8.7	$ 18,193	-12.4	$ 25,974	$ 7,781
		$ 212,239,365		$ 17,536,321		$ 25,036,176	$ 7,499,855
		From 2019 Dismantling Study for Grand Meadow			-12.4% Note 2	$ 25,036,176	
High Bridge							
	E341	$ 71,147,957 D	-3.1	$ 2,205,587	-4.2	$ 2,952,934	$ 747,347
	E342	$ 753,399 D	-3.1	$ 23,355	-4.2	$ 31,269	$ 7,914
	E343	$ 67,960,213 D	-3.1	$ 2,106,767	-4.2	$ 2,820,630	$ 713,863
	E344	$ 210,175,920 D	-3.1	$ 6,515,454	-4.2	$ 8,723,169	$ 2,207,715
	E345	$ 52,014,326 D	-3.1	$ 1,612,444	-4.2	$ 2,158,809	$ 546,365
	E346	$ 7,144,763 D	-3.1	$ 221,488	-4.2	$ 296,537	$ 75,050
		$ 409,196,577		$ 12,685,094		$ 16,983,348	$ 4,298,254
		From 2019 Dismantling Study for High Bridge			-4.2%	$ 16,983,348	

FERC Account		Plant Balance 1/1/2022 (1)		Present: Net Salv % (2)	Present: Estimated Net Salvage in Reserve at End of Life (3)	Proposed: Net Salv % (4)	Proposed: Estimated Net Salvage in Reserve at End of Life (5)	Proposed Less Present (6)
Inver Hills								
	E341	$ 1,617,415	D	-11.0	$ 177,916	-20.3	$ 327,702	$ 149,786
	E342	$ 599,614	D	-11.0	$ 65,957	-20.3	$ 121,487	$ 55,529
	E344	$ 50,980,595	D	-11.0	$ 5,607,865	-20.3	$ 10,329,091	$ 4,721,226
	E345	$ 4,309,713	D	-11.0	$ 474,068	-20.3	$ 873,184	$ 399,115
	E346	$ 617,845	D	-11.0	$ 67,963	-20.3	$ 125,180	$ 57,218
		$ 58,125,181			$ 6,393,770		$ 11,776,644	$ 5,382,874
		From 2019 Dismantling Study for Inver Hills				-20.3%	$ 11,776,644	
Lake Benton II Wind								
	E340	$ -	D	0.0	$ -	0.0	$ -	$ -
	E341	$ 33,079,253	D	-8.5	$ 2,811,736	-10.5	$ 3,460,075	$ 648,339
	E344	$ 116,607,126	D	-8.5	$ 9,911,606	-10.5	$ 12,197,054	$ 2,285,448
	E345	$ 11,207,318	D	-8.5	$ 952,622	-10.5	$ 1,172,281	$ 219,658
		$ 160,893,697			$ 13,675,964		$ 16,829,410	$ 3,153,445
		From 2019 Dismantling Study for Lake Benton II				-10.5% Note 2	$ 16,829,410	
Nobles Wind								
	E340	$ 3,884,834	D	0.0	$ -	0.0	$ -	$ -
	E341	$ 13,536,911	D	-8.7	$ 1,177,711	-8.5	$ 1,145,485	$ (32,227)
	E344	$ 470,979,873	D	-8.7	$ 40,975,249	-8.5	$ 39,854,013	$ (1,121,236)
	E345	$ 29,969,729	D	-8.7	$ 2,607,366	-8.5	$ 2,536,019	$ (71,347)
	E346	$ 627,971	D	-8.7	$ 54,633	-8.5	$ 53,138	$ (1,495)
		$ 518,999,319			$ 44,814,960		$ 43,588,656	$ (1,226,304)
		From 2019 Dismantling Study for Nobles				-8.5% Note 2	$ 43,588,656	
Pleasant Valley Wind								
	E341	$ 25,806,960	D	-8.5	$ 2,193,592	-11.7	$ 3,006,889	$ 813,298
	E344	$ 263,869,298	D	-8.5	$ 22,428,890	-11.7	$ 30,744,645	$ 8,315,754
	E345	$ 42,507,679	D	-8.5	$ 3,613,153	-11.7	$ 4,952,768	$ 1,339,616
	E346	$ 292,092	D	-8.5	$ 24,828	-11.7	$ 34,033	$ 9,205
		$ 332,476,029			$ 28,260,462		$ 38,738,336	$ 10,477,873
		From 2019 Dismantling Study for Pleasant Valley				-11.7%	$ 38,738,336	
Riverside								
	E341	$ 52,858,845	D	-5.0	$ 2,642,942	-12.2	$ 6,435,028	$ 3,792,086
	E342	$ 2,059,988	D	-5.0	$ 102,999	-12.2	$ 250,783	$ 147,783
	E343	$ 51,482,617	D	-5.0	$ 2,574,131	-12.2	$ 6,267,486	$ 3,693,356
	E344	$ 176,489,317	D	-5.0	$ 8,824,466	-12.2	$ 21,485,784	$ 12,661,318
	E345	$ 40,495,707	D	-5.0	$ 2,024,785	-12.2	$ 4,929,942	$ 2,905,156
	E346	$ 11,142,086	D	-5.0	$ 557,104	-12.2	$ 1,356,436	$ 799,332
		$ 334,528,560			$ 16,726,428		$ 40,725,459	$ 23,999,031
		From 2019 Dismantling Study for Riverside				-12.2%	$ 40,725,459	
Total Other Production		$ 3,700,013,414			$ 240,733,419		$ 363,380,897	$ 122,647,479

Note 1: As TLG's estimate was for the entire Black Dog site including the former steam units, the Company performed analysis and calculations to determine the portions attributable to the steam demolition versus the future removal for the other production units and common/shared facilities.

Note 2: To calculate the proposed net salvage percent, FERC 340 Wind Rights was excluded from the plant balance as removal costs do not apply to this account.

Note 3: Border, Courtenay, and Foxtail wind farms are located in North Dakota which only requires removal to a depth of 48". Thus, the 48" removal scenario was used to calculate the net salvage rate.

E

company_id	company_desc	depr_group_desc	Depr Grp Mapping	depr_group_status	func_class	depr_summary2	depr_summary	effective_date
56	NSP-Minnesota	MN00-None/Unspecified	#N/A	INVALID		Common General	Nonregulated Plant & Equipment	3/1/2014 0:00
56	NSP-Minnesota	MN01-10182371-Non-Depr Intang NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182383-Hennepin Island-NSC	#N/A	VALID	Electric Hydro Production Plant	Pension Benefits Non-Service Costs	Hydro Production Conventional	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182383-St Croix Falls-NSC	#N/A	VALID	Electric Hydro Production Plant	Pension Benefits Non-Service Costs	Hydro Production Conventional	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-Coal Cars-NSC	#N/A	VALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-King-NSC	#N/A	VALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	12/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-MN Valley-NSC	#N/A	INVALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-Red Wing-NSC	#N/A	VALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-Sherco 1&2-NSC	#N/A	VALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-Sherco 3-202212-NSC	#N/A	VALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182384-Wilmarth-NSC	#N/A	VALID	Electric Steam Production Plant	Pension Benefits Non-Service Costs	Steam Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Angus Anson-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Black Dog #5-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Black Dog #6-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	7/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Blaz Star 1 NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Wind Production	3/1/2020 0:00
56	NSP-Minnesota	MN01-10182385-Blue Lake 7&8-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Blue Lake-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Courtenay Wind-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Wind Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Faribault-NSC	#N/A	INVALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Foxtail WF NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Fuel Wind Storage-NSC	#N/A	VALID	Electric Hydro Production Plant	Pension Benefits Non-Service Costs	Hydro Production Conventional	1/1/2018 0:00
56	NSP-Minnesota	MN01-10182385-Granite City-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2018 0:00
56	NSP-Minnesota	MN01-10182385-High Bridge-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Inver Hills-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Key City-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Lk Benton WF NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Wind Production	11/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Mankato EC NSC	#N/A	INVALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	3/1/2019 0:00
56	NSP-Minnesota	MN01-10182385-Nobles WF-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Wind Production	12/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Pleasant Valley-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Wind Production	12/1/2017 0:00
56	NSP-Minnesota	MN01-10182385-Riverside-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2018 0:00
56	NSP-Minnesota	MN01-10182385-United-NSC	#N/A	VALID	Electric Other Production Plant	Pension Benefits Non-Service Costs	Other Production	1/1/2018 0:00
56	NSP-Minnesota	MN01-10182387-Monticello-NSC	#N/A	VALID	Electric Nuclear Production Plant	Pension Benefits Non-Service Costs	Nuclear Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10182387-Nuclear Prod HFU-NSC	#N/A	VALID	Electric Nuclear Production Plant	Pension Benefits Non-Service Costs	Nuclear Production	1/1/2018 0:00
56	NSP-Minnesota	MN01-10182387-Prairie Island-NSC	#N/A	VALID	Electric Nuclear Production Plant	Pension Benefits Non-Service Costs	Nuclear Production	8/1/2017 0:00
56	NSP-Minnesota	MN01-10253010-Steam-ASK-PF-AFDC	#N/A	VALID	Electric Steam Production Plant	Pre-Funded AFUDC-MERP	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253010-Steam-RIV-PF-AFDC	#N/A	INVALID	Electric Steam Production Plant	Pre-Funded AFUDC-MERP	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253012-Steam-KING-PF AFDC	#N/A	VALID	Electric Steam Production Plant	Pre-Funded AFUDC-MERCURY	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253012-Stm-SHERCO1-2-PF AFDC	#N/A	VALID	Electric Steam Production Plant	Pre-Funded AFUDC-MERCURY	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253012-Stm-SHERCO3-PF AFDC	#N/A	VALID	Electric Steam Production Plant	Pre-Funded AFUDC-MERCURY	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253040-Other-HBR-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-MERP	Other Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253040-Other-RIV-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-MERP	Other Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253045-Oth-Benton WF-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253045-Oth-Blaz St 1-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	3/1/2020 0:00
56	NSP-Minnesota	MN01-10253045-Other-Crtny-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253045-Other-GMWF-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253045-Other-Nobles-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253045-Other-WTB-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-10253045-Oth-Foxtail-PF AFDC	#N/A	VALID	Electric Other Production Plant	Pre-Funded AFUDC-RES	Wind Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-182300-Sherco 3 Depr Deferral	Sherco 3 DeferralSherco 3 Deferral	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-182-Stm Blk Dg Remed Reg	10182Black Dog Remediation	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-302001-Franchise-Hennepin Is	10302Hennepin Island	VALID	Electric Intangible Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00
56	NSP-Minnesota	MN01-302002-Franchise-Monticello	10302Monticello	VALID	Electric Intangible Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-302002-Franchise-Prairie Islnd	10302Prairie Island	VALID	Electric Intangible Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-303004-Sfwr-General A	#N/A	VALID	Electric Intangible Plant	Electric Production	Electric Software	1/1/2020 0:00
56	NSP-Minnesota	MN01-303-Theo Res Amort MN	#N/A	VALID	Electric Intangible Plant	Electric General	Electric Software	12/1/2013 0:00
56	NSP-Minnesota	MN01-303-Theo Res Depr MN	#N/A	VALID	Electric Intangible Plant	Electric General	Electric Software	12/1/2017 0:00
56	NSP-Minnesota	MN01-310001-Fee Land	10310Land	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-310002-Land Rights	10310Land Rights	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Black Dog	10311Black Dog	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Black Dog #2	10311Black Dog	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-High Br #4	10311High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-High Bridge	10311High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-King	10311Allen S. King	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-MN Valley	10311MN Valley	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-MN Vly Edike	10311MN Valley	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-MN Vly Wdike	10311MN Valley	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Pathfinder	10311Pathfinder	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Red Wing	10311Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Red Wing Ash	10311Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Red Wing RDF	10311Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Riverside	10311Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Riverside #7	10311Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Sherco 1	10311Sherco 1&2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Sherco 1&2	10311Sherco 1&2	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Sherco 1&2 C	10311Sherco 1&2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Sherco 2	10311Sherco 1&2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Sherco 3	10311Sherco 3	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Wilmarth	10311Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Wilmarth Ash	10311Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-311000-Str & Impr-Wilmarth RDF	10311Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Black Dog	10312Black Dog	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Black Dog #2	10312Black Dog	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-High Br #4	10312High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-High Bridge	10312High Bridge - Steam	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-King	10312Allen S. King	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-MN Valley	10312MN Valley	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Pathfinder	10312Pathfinder	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Red Wing	10312Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Riversd Demo	10312Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Riverside	10312Riverside - Steam	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Riverside #7	10312Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Sherco 1	10312Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Sherco 1&2	10312Sherco 1	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Sherco 1&2 C	10312Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Sherco 2	10312Sherco 2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Sherco 3	10312Sherco 3	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312000-Blr Plt Eq-Wilmarth	10312Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-312200-Coal Cars		VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Black Dog	10314Black Dog	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Black Dog #2	10314Black Dog	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-High Br #4	10314High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-High Bridge	10314High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-King	10314Allen S. King	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-MN Valley	10314MN Valley	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Pathfinder	10314Pathfinder	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Red Wing	10314Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Riverside	10314Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Riverside #7	10314Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Sherco 1	10314Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Sherco 1&2	10314Sherco 1	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Sherco 1&2 C	10314Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Sherco 2	10314Sherco 2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Sherco 3	10314Sherco 3	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-Turbo Gen-Wilmarth	10314Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-314000-TurboGen-Sherco 3-105	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	3/1/2014 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Black Dog	10315Black Dog	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Black Dog #2	10315Black Dog	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-High Br #4	10315High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-High Bridge	10315High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-King	10315Allen S. King	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-MN Valley	10315MN Valley	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Pathfinder	10315Pathfinder	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Red Wing	10315Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Riverside	10315Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Riverside #7	10315Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Sherco 1	10315Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Sherco 1&2	10315Sherco 1	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Sherco 1&2 C	10315Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Sherco 2	10315Sherco 2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Sherco 3	10315Sherco 3	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Sherco 3-105	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	3/1/2014 0:00
56	NSP-Minnesota	MN01-315000-Acc El Eq-Wilmarth	10315Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Black Dog	10316Black Dog	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Black Dog #2	10316Black Dog	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-High Br #4	10316High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-High Bridge	10316High Bridge - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-King	10316Allen S. King	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-MN Valley	10316MN Valley	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Pathfinder	10316Pathfinder	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Red Wing	10316Red Wing	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Riverside	10316Riverside - Steam	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Riverside #7	10316Riverside - Steam	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Sherco 1	10316Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Sherco 1&2	10316Sherco 1	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Sherco 1&2 C	10316Sherco 1	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Sherco 2	10316Sherco 2	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Sherco 3	10316Sherco 3	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-316000-Pwr Pl Eq-Wilmarth	10316Wilmarth	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-317000-Steam Prod ARC-Misc.	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-317000-Stm Prd ARC-Coal Yard	#N/A	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Blk Dg 3&4	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Blk Dg Pnd	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-High Bridg	#N/A	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Inver Hill	#N/A	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-King	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-MN Valley	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Pathfinder	#N/A	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Ponds	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Red Wing	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Riverside	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Sherco #3	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Sherco 1&2	#N/A	INVALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Sherco Rad	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-317000-Stm Prod ARC-Wilmarth	#N/A	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2016 0:00
56	NSP-Minnesota	MN01-320001-Fee Land	10320Land	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-320002-Land Rights	10320Land Rights	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-Monti	10321Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-Monti-Casks	10321Monti Interim Storage	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-Monti-LE	10321Monticello	INVALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-Monti-Tr Ctr	10321Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-PI	10321Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-PI Dry Casks	10321PI Interim Storage	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-321000-Str & Impr-PI-Trng Ctr	10321Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-322000-Reactor Eq-Monti	10322Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-322000-Reactor Eq-Monti Casks	10322Monti Interim Storage	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-322000-Reactor Eq-Monti-HFU	#N/A	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-322000-Reactor Eq-PI	10322Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-322000-Reactor Eq-PI Dry Casks	10322PI Interim Storage	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-322000-Reactor Eq-PI-HFU	#N/A	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-323000-Turbogentr-Monti	10323Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-323000-Turbogentr-PI	10323Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-324000-Accessy Eq-Monti	10324Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-324000-Accessy Eq-Monti-Trg Ct	10324Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-324000-Accessy Eq-PI	10324Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-324000-Accessy Eq-PI Trng Ctr	10324Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325000-Misc Pl Eq-Monti	10325Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325000-Misc Pl Eq-Monti-Trg Ct	10325Monticello	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325000-Misc Pl Eq-PI	10325Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325000-Misc Pl Eq-PI-Trng Ctr	10325Prairie Island	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325001-DCM-Int-Monti-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325001-DCM-Int-Monti-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325001-DCM-Int-Monti-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325001-DCM-Int-Monti-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00
56	NSP-Minnesota	MN01-325001-DCM-Int-Monti-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00

56	NSP-Minnesota	MN01-325001-DCM-Int-Monti-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894529	0	MN01-325001-DCM-Int-Monti-WI	20936984	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 1-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894752	0	MN01-325001-DCM-Int-PI 1-FM	20936987	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 1-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894798	0	MN01-325001-DCM-Int-PI 1-FW	20936988	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 1-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894648	0	MN01-325001-DCM-Int-PI 1-MN	20936985	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 1-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894851	0	MN01-325001-DCM-Int-PI 1-ND	20936989	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 1-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894693	0	MN01-325001-DCM-Int-PI 1-SD	20936986	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 1-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30894900	0	MN01-325001-DCM-Int-PI 1-WI	20936990	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 2-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895106	0	MN01-325001-DCM-Int-PI 2-FM	20936993	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 2-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895151	0	MN01-325001-DCM-Int-PI 2-FW	20936994	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 2-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895015	0	MN01-325001-DCM-Int-PI 2-MN	20936991	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 2-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895202	0	MN01-325001-DCM-Int-PI 2-ND	20936995	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 2-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895060	0	MN01-325001-DCM-Int-PI 2-SD	20936992	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325001-DCM-Int-PI 2-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895250	0	MN01-325001-DCM-Int-PI 2-WI	20936996	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-Monti-FM	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895448	0	MN01-325002-DCM-Qual-Monti-FM	20936999	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-Monti-FW	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895493	0	MN01-325002-DCM-Qual-Monti-FW	20937000	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-Monti-MN	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895344	0	MN01-325002-DCM-Qual-Monti-MN	20936997	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-Monti-ND	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895552	0	MN01-325002-DCM-Qual-Monti-ND	20937001	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-Monti-SD	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895399	0	MN01-325002-DCM-Qual-Monti-SD	20936998	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-Monti-WI	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895601	0	MN01-325002-DCM-Qual-Monti-WI	20937002	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 1-FM	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895859	0	MN01-325002-DCM-Qual-PI 1-FM	20937005	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 1-FW	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895918	0	MN01-325002-DCM-Qual-PI 1-FW	20937006	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 1-MN	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895728	0	MN01-325002-DCM-Qual-PI 1-MN	20937003	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 1-ND	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895970	0	MN01-325002-DCM-Qual-PI 1-ND	20937007	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 1-SD	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30895795	0	MN01-325002-DCM-Qual-PI 1-SD	20937004	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 1-WI	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896023	0	MN01-325002-DCM-Qual-PI 1-WI	20937008	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 2-FM	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896267	0	MN01-325002-DCM-Qual-PI 2-FM	20937011	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 2-FW	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896332	0	MN01-325002-DCM-Qual-PI 2-FW	20937012	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 2-MN	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896132	0	MN01-325002-DCM-Qual-PI 2-MN	20937009	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 2-ND	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896410	0	MN01-325002-DCM-Qual-PI 2-ND	20937013	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 2-SD	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896217	0	MN01-325002-DCM-Qual-PI 2-SD	20937010	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325002-DCM-Qual-PI 2-WI	10325DCM	VALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896459	0	MN01-325002-DCM-Qual-PI 2-WI	20937014	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-Monti-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896656	0	MN01-325003-DCM-NQual-Monti-FM	20937017	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-Monti-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896704	0	MN01-325003-DCM-NQual-Monti-FW	20937018	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-Monti-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896536	0	MN01-325003-DCM-NQual-Monti-MN	20937015	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-Monti-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896755	0	MN01-325003-DCM-NQual-Monti-ND	20937019	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-Monti-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896605	0	MN01-325003-DCM-NQual-Monti-SD	20937016	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-Monti-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896817	0	MN01-325003-DCM-NQual-Monti-WI	20937020	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 1-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897032	0	MN01-325003-DCM-NQual-PI 1-FM	20937023	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 1-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897084	0	MN01-325003-DCM-NQual-PI 1-FW	20937024	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 1-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896887	0	MN01-325003-DCM-NQual-PI 1-MN	20937021	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 1-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897247	0	MN01-325003-DCM-NQual-PI 1-ND	20937025	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 1-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30896939	0	MN01-325003-DCM-NQual-PI 1-SD	20937022	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 1-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897303	0	MN01-325003-DCM-NQual-PI 1-WI	20937026	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 2-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897453	0	MN01-325003-DCM-NQual-PI 2-FM	20937029	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 2-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897506	0	MN01-325003-DCM-NQual-PI 2-FW	20937030	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 2-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897360	0	MN01-325003-DCM-NQual-PI 2-MN	20937027	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 2-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897551	0	MN01-325003-DCM-NQual-PI 2-ND	20937031	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 2-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897405	0	MN01-325003-DCM-NQual-PI 2-SD	20937028	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325003-DCM-NQual-PI 2-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30897648	0	MN01-325003-DCM-NQual-PI 2-WI	20937032	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-Monti-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554084	0	MN01-325004-DCM-NQual LT-Monti-FM	31336578	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-Monti-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554150	0	MN01-325004-DCM-NQual LT-Monti-FW	31336579	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-Monti-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554197	0	MN01-325004-DCM-NQual LT-Monti-MN	31336580	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-Monti-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554228	0	MN01-325004-DCM-NQual LT-Monti-ND	31336581	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-Monti-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554275	0	MN01-325004-DCM-NQual LT-Monti-SD	31336582	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-Monti-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554322	0	MN01-325004-DCM-NQual LT-Monti-WI	31336583	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 1-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554373	0	MN01-325004-DCM-NQual LT-PI 1-FM	31336584	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 1-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554420	0	MN01-325004-DCM-NQual LT-PI 1-FW	31336585	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 1-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554467	0	MN01-325004-DCM-NQual LT-PI 1-MN	31336586	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 1-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554514	0	MN01-325004-DCM-NQual LT-PI 1-ND	31336587	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 1-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554561	0	MN01-325004-DCM-NQual LT-PI 1-SD	31336588	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 1-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554608	0	MN01-325004-DCM-NQual LT-PI 1-WI	31336589	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 2-FM	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554655	0	MN01-325004-DCM-NQual LT-PI 2-FM	31336590	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 2-FW	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554702	0	MN01-325004-DCM-NQual LT-PI 2-FW	31336591	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 2-MN	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554749	0	MN01-325004-DCM-NQual LT-PI 2-MN	31336592	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 2-ND	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554796	0	MN01-325004-DCM-NQual LT-PI 2-ND	31336593	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 2-SD	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554843	0	MN01-325004-DCM-NQual LT-PI 2-SD	31336594	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-325004-DCM-NQual LT-PI 2-WI	10325DCM	INVALID	Decommissioning	Electric Production-DCM	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	32554890	0	MN01-325004-DCM-NQual LT-PI 2-WI	31336595	25400113	40300113	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-326000-Nucl Prod ARC-Monti	#N/A	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	11/1/2019 0:00	6	USED	1	SL	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	11417259	100	MN01-326000-Nuclear Prod ARC-Monti	561500	10800104	40301104	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	132475221.8	132475221.8
56	NSP-Minnesota	MN01-326000-Nucl Prod ARC-PI 1	#N/A	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	1/1/2016 0:00	6	USED	1	SL	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	11417352	100	MN01-326000-Nuclear Prod ARC-PI	561501	10800104	40301104	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-25286207.47	-25286207.47
56	NSP-Minnesota	MN01-326000-Nucl Prod ARC-PI 2	#N/A	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	1/1/2016 0:00	6	USED	1	SL	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	11417359	100	MN01-326000-Nuclear Prod ARC-PI	561501	10800104	40301104	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-113992334.1	-113992334.1
56	NSP-Minnesota	MN01-330001-Fee Land	10330Land	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	560094	0	MN01-330001-Fee Land	560094	10800107	40300107	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	292863.27	292863.27
56	NSP-Minnesota	MN01-330002-Land Rights	10330Land Rights	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	560095	0	MN01-330002-Land Rights	560095	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	165155.6	165155.6
56	NSP-Minnesota	MN01-330002-Land Rights-Amortized	10330Land Rights - Amortized	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	560096	0	MN01-330002-Land Rights-Amortized	560096	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	1235057.41	1235057.41
56	NSP-Minnesota	MN01-331000-Str & Impr-Hennepin Is	10331Hennepin Island	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R2.5	NSPM-ND-C-PU-12-813	560097	0	MN01-331000-Str & Impr-Hennepin Is	560097	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1407680.04	1407680.04
56	NSP-Minnesota	MN01-331000-Str & Impr-Lower Dam	10331Lower Dam	INVALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R2.5	NSP-MN DEPRECIATION BLENDING	560098	0	MN01-331000-Str & Impr-Lower Dam	560098	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-331000-Str & Impr-St Croix Fls	10331St Croix Falls	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.075	0	0	-0.075	202712	R2.5	NSP-MN DEPRECIATION BLENDING	560099	0	MN01-331000-Str & Impr-St Croix Fls	560099	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	37924.25	37924.25
56	NSP-Minnesota	MN01-332000-Reservoirs-Hennepin Is	10332Hennepin Island	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R3	NSPM-ND-C-PU-12-813	560100	0	MN01-332000-Reservoirs-Hennepin Is	560100	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	4398483.5	4398483.5
56	NSP-Minnesota	MN01-332000-Reservoirs-Lower Dam	10332Lower Dam	INVALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R3	NSP-MN DEPRECIATION BLENDING	560101	0	MN01-332000-Reservoirs-Lower Dam	560101	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-332000-Reservoirs-St Croix Fls	10332St Croix Falls	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.075	0	0	-0.075	202712	R3	NSP-MN DEPRECIATION BLENDING	560102	0	MN01-332000-Reservoirs-St Croix Fls	560102	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	2196155.83	2196155.83
56	NSP-Minnesota	MN01-332000-Reservoirs-Upper Dam	10332Upper Dam	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R3	NSPM-ND-C-PU-12-813	560103	0	MN01-332000-Reservoirs-Upper Dam	560103	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	4491476.08	4491476.08
56	NSP-Minnesota	MN01-333000-Turb & Gen-Hennepin Is	10333Hennepin Island	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R1.5	NSPM-ND-C-PU-12-813	560104	0	MN01-333000-Turb & Gen-Hennepin Is	560104	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	10156575.05	10156575.05
56	NSP-Minnesota	MN01-334000-Accessy Eq-Hennepin Is	10334Hennepin Island	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R2.5	NSPM-ND-C-PU-12-813	560105	0	MN01-334000-Accessy Eq-Hennepin Is	560105	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	3256972.38	3256972.38
56	NSP-Minnesota	MN01-335000-Misc Pl Eq-Hennepin Is	10335Hennepin Island	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R2.5	NSPM-ND-C-PU-12-813	560106	0	MN01-335000-Misc Pl Eq-Hennepin Is	560106	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	37778.5	37778.5
56	NSP-Minnesota	MN01-335000-Misc Pl Eq-Upper Dam	10335Upper Dam	VALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.3	0	0	-0.3	203402	R2.5	NSPM-ND-C-PU-12-813	560107	0	MN01-335000-Misc Pl Eq-Upper Dam	560107	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	23045.77	23045.77
56	NSP-Minnesota	MN01-337000-Hyd Prod ARC-Henn Islan	#N/A	INVALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	1/1/2016 0:00	6	USED	1	SL	0	0	0	0	0	0				780318382	100	MN01-337000-Hyd Prod ARC-Henn Islan	63944717	10800104	40301104	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-337000-Hyd Prod ARC-St Anthony	#N/A	INVALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	1/1/2016 0:00	6	USED	1	SL	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	30675980	100	MN01-337000-Hyd Prod ARC-St An Fall	20936970	10800104	40301104	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-337000-Hydro Prod ARC-Misc.	#N/A	INVALID	Electric Hydro Production Plant	Electric Production	Hydro Production Conventional	12/1/2019 0:00	6	USED	1	SL	0	0	0	0	0	0				564881759	100	MN01-10337000-Hydro Prod ARC-Misc.	63944665	10800104	40301104	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-340001-Fee Land	10340Land	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	560108	0	MN01-340001-Fee Land	560108	10800107	40300107	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	5443012.02	5627598.26
56	NSP-Minnesota	MN01-340002-Land Rights	10340Land Rights	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	560109	0	MN01-340002-Land Rights	560109	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	10367651.91	10367651.91
56	NSP-Minnesota	MN01-340045-Wind Rights-Blaz Star 1	10340Blazing Star I WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	3/1/2020 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	204504		NSPM-MN-EG002-D-19-161	2201546724	0	MN01-340045-Wind Rights-Blaz Star 1	63945293	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-340045-Wind Rights-Border Wind	10340Border WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	204012			836216181	0	MN01-340045-Wind Rights-Border Wind	63944782	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-340045-Wind Rights-Crtny Wind	10340045Courtenay WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	204111			989790213	0	MN01-340045-Wind Rights-Crtny Wind	63944839	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	2085660.57	2085660.57
56	NSP-Minnesota	MN01-340045-Wind Rights-Foxtail WF	10340045Foxtail WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	204412		NSPM-MN-EG002-D-19-161	2181443622	0	MN01-340045-Wind Rights-Foxtail WF	63945290	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	179743.34	179743.34
56	NSP-Minnesota	MN01-340045-Wind Rights-Gr Meadow	10340045Grand Meadow	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	203311		NSP-MN DEPRECIATION BLENDING	54623389	0	MN01-340045-Wind Rights-Gr Meadow	49750561	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	10672452.12	10672452.12
56	NSP-Minnesota	MN01-340045-Wind Rights-Lk Benton W	10340045Lake Benton WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	204411		NSPM-MN-EG002-D-19-161	2154435532	0	MN01-340045-Wind Rights-Lk Benton W	63945273	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-340045-Wind Rights-Nobles	10340045Nobles	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	203511			101691410	0	MN01-340045-Wind Rights-Nobles	63944411	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	3884834.46	3884834.46
56	NSP-Minnesota	MN01-340045-Wind Rights-Pleasant V	10340045Pleasant Valley WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	204012			830447208	0	MN01-340045-Wind Rights-Pleasant V	63944768	11100140	40400141	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-341000-Str & Impr-Angus Anson	10341Angus C. Anson - 2 & 3	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.045	0	0	-0.045	203812	R1.5	NSPM-ND-C-PU-12-813	560110	0	MN01-341000-Str & Impr-Angus Anson	560110	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	7614499.95	7614499.95
56	NSP-Minnesota	MN01-341000-Str & Impr-Angus Anson4	10341Angus C. Anson - 4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.045	0	0	-0.045	203812		NSPM-ND-C-PU-12-813	24744246	0	MN01-341000-Str & Impr-Angus Anson4	20936949	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	101834.23	101834.23
56	NSP-Minnesota	MN01-341000-Str & Impr-Black Dog #5	10341Black Dog 5	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.025	0	0	-0.025	203112	R1.5	NSPM-ND-C-PU-12-813	8334108	0	MN01-341000-Str & Impr-Black Dog #5	620723	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	43297529.82	43303727.82
56	NSP-Minnesota	MN01-341000-Str & Impr-Black Dog #6	10341Black Dog 6	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	205803			1568318519	0	MN01-341000-Str & Impr-Black Dog #6	63945146	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	13824591.5	13824591.5
56	NSP-Minnesota	MN01-341000-Str & Impr-Blue Lake	10341Blue Lake 1-4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.052	0	0	-0.052	203505	R1.5	NSPM-ND-C-PU-12-813	560111	0	MN01-341000-Str & Impr-Blue Lake	560111	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1153722.65	1153722.65
56	NSP-Minnesota	MN01-341000-Str & Impr-Blue Lake7&8	10341Blue Lake 7&8	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.052	0	0	-0.052	203505		NSPM-ND-C-PU-12-813	24744690	0	MN01-341000-Str & Impr-Blue Lake7&8	20936958	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	549731.59	549731.59
56	NSP-Minnesota	MN01-341000-Str & Impr-Granite City	10341Granite City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.388	0	0	-0.388	201312	R1.5	NSPM-ND-C-PU-12-813	560112	0	MN01-341000-Str & Impr-Granite City	560112	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-341000-Str & Impr-High BridgeM	10341High Bridge - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.031	0	0	-0.031	205305		NSPM-ND-C-PU-12-813	13650170	0	MN01-341000-Str & Impr-High BridgeM	620887	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	71288455.92	71299230.07
56	NSP-Minnesota	MN01-341000-Str & Impr-Holland Wind	10341Holland WF	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	18214334	0	MN01-341000-Str & Impr-Holland Wind	621083	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-341000-Str & Impr-Inver Hills	10341Inver Hills	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.11	0	0	-0.11	202612	R1.5	NSPM-ND-C-PU-12-813	560113	0	MN01-341000-Str & Impr-Inver Hills	560113	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1579722.45	1579722.45
56	NSP-Minnesota	MN01-341000-Str & Impr-Key City	10341Key City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.386	0	0	-0.386	201412	R1.5	NSPM-ND-C-PU-12-813	560114	0	MN01-341000-Str & Impr-Key City	560114	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-341000-Str & Impr-RiversideM	10341Riverside - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	204902		NSPM-ND-C-PU-12-813	13650190	0	MN01-341000-Str & Impr-RiversideM	620892	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	52479797.77	52479797.77
56	NSP-Minnesota	MN01-341000-Str & Impr-W Faribault	10341West Faribault	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.48	0	0.4	0	0	-0.4	200612	R1.5	NSP-MN DEPRECIATION BLENDING	560115	0	MN01-341000-Str & Impr-W Faribault	560115	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-341045-Str & Impr-Blaz Star 1	10341Blazing Star I WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	3/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204504		NSPM-MN-EG002-D-19-161	2201546750	0	MN01-341045-Str & Impr-Blaz Star 1	63945294	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	22599517.58	22655902.3
56	NSP-Minnesota	MN01-341045-Str & Impr-Border Wind	10341Border WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.066	0	0	-0.066	204012		NSPM-ND-Elec-PU-18-228	836216228	0	MN01-341045-Str & Impr-Border Wind	63944783	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	22226431.78	22226431.78
56	NSP-Minnesota	MN01-341045-Str & Impr-Crtny Wind	10341Courtenay WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.069	0	0	-0.069	204111		NSPM-ND-Elec-PU-17-020	989799267	0	MN01-341045-Str & Impr-Crtny Wind	63944840	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	7621663.64	7621663.64
56	NSP-Minnesota	MN01-341045-Str & Impr-Foxtail WF	10341Foxtail WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	2/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.064	0	0	-0.064	204412		Specific filing	2181443623	0	MN01-341045-Str & Impr-Foxtail WF	63945286	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	33989963.4	32881412.43
56	NSP-Minnesota	MN01-341045-Str & Impr-Gr Meadow WF	10341Grand Meadow	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203311		NSPM-ND-C-PU-12-813	54716085	0	MN01-341045-Str & Impr-Gr Meadow WF	49750562	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	5589344.45	5589344.45
56	NSP-Minnesota	MN01-341045-Str & Impr-Lk Benton WF	10341Lake Benton WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204411		NSPM-MN-EG002-D-19-161	2154435547	0	MN01-341045-Str & Impr-Lk Benton WF	63945274	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	32345190.07	32364759.79
56	NSP-Minnesota	MN01-341045-Str & Impr-Nobles	10341Nobles	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203511		NSPM-ND-C-PU-12-813	101691415	0	MN01-341045-Str & Impr-Nobles	63944412	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	13536911.32	13536911.32
56	NSP-Minnesota	MN01-341045-Str & Impr-Pleasant V	10341Pleasant Valley WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204012			830447553	0	MN01-341045-Str & Impr-Pleasant V	63944769	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	25806960.08	25806960.08
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Angus Anson	10342Angus C. Anson - 2 & 3	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.044	0	0	-0.044	203812	R1.5	NSPM-ND-C-PU-12-813	560116	0	MN01-342000-Fuel Holdr-Angus Anson	560116	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1070423.22	1070423.22
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Angus Anson4	10342Angus C. Anson - 4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.045	0	0	-0.045	203812		NSPM-ND-C-PU-12-813	24744370	0	MN01-342000-Fuel Holdr-Angus Anson4	20936950	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	13505.89	13505.89
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Black Dog #5	10342Black Dog 5	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.025	0	0	-0.025	203112	R1.5	NSPM-ND-C-PU-12-813	8333805	0	MN01-342000-Fuel Holdr-Black Dog #5	620719	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	12548304.18	12548304.18
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Black Dog #6	10342Black Dog 6	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	205803			1568354714	0	MN01-342000-Fuel Holdr-Black Dog #6	63945147	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	9512174.85	9512174.85
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Blue Lake	10342Blue Lake 1-4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.119	0	0	-0.119	201212	R1.5	NSPM-ND-C-PU-12-813	560117	0	MN01-342000-Fuel Holdr-Blue Lake	560117	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1340395.3	1340395.3
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Blue Lake7&8	10342Blue Lake 7&8	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.052	0	0	-0.052	203505		NSPM-ND-C-PU-12-813	24744739	0	MN01-342000-Fuel Holdr-Blue Lake7&8	20936957	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	47985.66	47985.66
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Granite City	10342Granite City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.388	0	0	-0.388	201312	R1.5	NSPM-ND-C-PU-12-813	560118	0	MN01-342000-Fuel Holdr-Granite City	560118	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342000-Fuel Holdr-High BridgeM	10342High Bridge - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.031	0	0	-0.031	205305		NSPM-ND-C-PU-12-813	13650172	0	MN01-342000-Fuel Holdr-High BridgeM	620888	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	612010.98	612010.98
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Inver Hills	10342Inver Hills	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.11	0	0	-0.11	202612	R1.5	NSPM-ND-C-PU-12-813	560119	0	MN01-342000-Fuel Holdr-Inver Hills	560119	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	599613.56	599613.56
56	NSP-Minnesota	MN01-342000-Fuel Holdr-Key City	10342Key City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.386	0	0	-0.386	201412	R1.5	NSPM-ND-C-PU-12-813	560120	0	MN01-342000-Fuel Holdr-Key City	560120	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342000-Fuel Holdr-RiversideM	10342Riverside - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	204902		NSPM-ND-C-PU-12-813	13650193	0	MN01-342000-Fuel Holdr-RiversideM	620893	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1049871.09	1049608.56
56	NSP-Minnesota	MN01-342000-Fuel Holdr-W Faribault	10342West Faribault	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.48	0	0.4	0	0	-0.4	200612	R1.5	NSP-MN DEPRECIATION BLENDING	560121	0	MN01-342000-Fuel Holdr-W Faribault	560121	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342010-Fuel Holdr-Wind/Storage	10342Wind Storage	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	202401		NSP-MN DEPRECIATION BLENDING	43414219	0	MN01-342010-Fuel Holdr-Wind/Storage	41818999	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Blaz Star 1	10342Blazing Star I WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	3/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204504		NSPM-MN-EG002-D-19-161	2201546753	0	MN01-342045-Fuel Holdr-Blaz Star 1	63945295	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Border Wind	10342Border WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.066	0	0	-0.066	204012		NSPM-ND-Elec-PU-18-228	836216229	0	MN01-342045-Fuel Holdr-Border Wind	63944784	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Crtny Wind	10342Courtenay WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.069	0	0	-0.069	204111		NSPM-ND-Elec-PU-17-020	989824303	0	MN01-342045-Fuel Holdr-Crtny Wind	63944841	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Foxtail WF	10342Foxtail WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	2/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.064	0	0	-0.064	204412		Specific filing	2181443624	0	MN01-342045-Fuel Holdr-Foxtail WF	63945287	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Gr Meadow WF	10342Grand Meadow	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203311		NSPM-ND-C-PU-12-813	54716135	0	MN01-342045-Fuel Holdr-Gr Meadow WF	49750565	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Lk Benton WF	10342Lake Benton WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204411		NSPM-MN-EG002-D-19-161	2154435548	0	MN01-342045-Fuel Holdr-Lk Benton WF	63945275	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Nobles WF	10342Nobles	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203511		NSPM-ND-C-PU-12-813	101713342	0	MN01-342045-Fuel Holdr-Nobles WF	63944428	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-342045-Fuel Holdr-Pleasant V	10342Pleasant Valley WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204012			830447793	0	MN01-342045-Fuel Holdr-Pleasant V	63944773	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-343000-Prime Movers-RiversideM	10343Riverside - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	204902		NSPM-ND-C-PU-12-813	1412849930	0	MN01-343000-Prime Movers-RiversideM	63945136	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	50677325.45	50688587.81
56	NSP-Minnesota	MN01-343000-PrimeMover-Black Dog #5	10343Black Dog 5	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.025	0	0	-0.025	203112		NSPM-ND-C-PU-12-813	1412813199	0	MN01-343000-PrimeMover-Black Dog #5	63945134	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	23559163.04	23551676.42
56	NSP-Minnesota	MN01-343000-PrimeMover-Black Dog #6	10343Black Dog 6	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	205803			1568355094	0	MN01-343000-PrimeMover-Black Dog #6	63945148	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-343000-PrimeMover-High BridgeM	10343High Bridge - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.031	0	0	-0.031	205305		NSPM-ND-C-PU-12-813	1412831195	0	MN01-343000-PrimeMover-High BridgeM	63945135	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	66798100.43	66798049.92
56	NSP-Minnesota	MN01-344000-Generators-Alliant Tech	10344Alliant Tech	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.112152	0	0	0	0	0	201210	R1.5	NSP-MN DEPRECIATION BLENDING	560122	0	MN01-344000-Generators-Alliant Tech	560122	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-Angus Anson	10344Angus C. Anson - 2 & 3	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.044	0	0	-0.044	203812	R1.5	NSPM-ND-C-PU-12-813	560123	0	MN01-344000-Generators-Angus Anson	560123	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	79838254.72	79869871.75
56	NSP-Minnesota	MN01-344000-Generators-Angus Anson4	10344Angus C. Anson - 4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.045	0	0	-0.045	203812		NSPM-ND-C-PU-12-813	24744504	0	MN01-344000-Generators-Angus Anson4	20936951	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	33549519.62	33549509.04
56	NSP-Minnesota	MN01-344000-Generators-Black Dog #5	10344Black Dog 5	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.025	0	0	-0.025	203112	R1.5	NSPM-ND-C-PU-12-813	8333807	0	MN01-344000-Generators-Black Dog #5	620720	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	126795219.5	126799656.8
56	NSP-Minnesota	MN01-344000-Generators-Black Dog #6	10344Black Dog 6	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	205803			1568372902	0	MN01-344000-Generators-Black Dog #6	63945149	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	62269985.47	62269985.47
56	NSP-Minnesota	MN01-344000-Generators-Blue Lake	10344Blue Lake 1-4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.119	0	0	-0.119	201212	R1.5	NSPM-ND-C-PU-12-813	560124	0	MN01-344000-Generators-Blue Lake	560124	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	21204714.83	21204714.83
56	NSP-Minnesota	MN01-344000-Generators-Blue Lake7&8	10344Blue Lake 7&8	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.052	0	0	-0.052	203505		NSPM-ND-C-PU-12-813	24744784	0	MN01-344000-Generators-Blue Lake7&8	20936956	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	62365135.96	62365145.27
56	NSP-Minnesota	MN01-344000-Generators-Granite City	10344Granite City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.388	0	0	-0.388	201312	R1.5	NSPM-ND-C-PU-12-813	560125	0	MN01-344000-Generators-Granite City	560125	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-High BridgeM	10344High Bridge - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.031	0	0	-0.031	205305		NSPM-ND-C-PU-12-813	13650174	0	MN01-344000-Generators-High BridgeM	620889	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	209026315.5	209026433.9
56	NSP-Minnesota	MN01-344000-Generators-Holland	10344Holland WF	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	199912	R1.5	NSP-MN DEPRECIATION BLENDING	560126	0	MN01-344000-Generators-Holland	560126	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-Inver Hills	10344Inver Hills	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.11	0	0	-0.11	202612	R1.5	NSPM-ND-C-PU-12-813	560127	0	MN01-344000-Generators-Inver Hills	560127	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	52562415.8	52575360.34
56	NSP-Minnesota	MN01-344000-Generators-Key City	10344Key City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.386	0	0	-0.386	201412	R1.5	NSPM-ND-C-PU-12-813	560128	0	MN01-344000-Generators-Key City	560128	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-Lake Benton	10344Lake Benton	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.071004	0	0	0	0	0	201412	R1.5	NSP-MN DEPRECIATION BLENDING	560129	0	MN01-344000-Generators-Lake Benton	560129	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-MEC	10344Mankato Energy Center	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.06	0	0	-0.06	205202			1736545334	0	MN01-344000-Generators-MEC	63945226	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-Photovoltaic	10344Photo Voltaic	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0	199912		NSP-MN DEPRECIATION BLENDING	560130	0	MN01-344000-Generators-Photovoltaic	560130	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-RiversideM	10344Riverside - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	204902		NSPM-ND-C-PU-12-813	13650196	0	MN01-344000-Generators-RiversideM	620894	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	154934423.5	155888616.9
56	NSP-Minnesota	MN01-344000-Generators-United Hlth	10344United Health	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.131868	0	0	0	0	0	200802	R1.5	NSP-MN DEPRECIATION BLENDING	560131	0	MN01-344000-Generators-United Hlth	560131	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-United Hosp	10344United Hospital	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	201708	R1.5	NSPM-ND-C-PU-12-813	560132	0	MN01-344000-Generators-United Hosp	560132	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344000-Generators-W Faribault	10344West Faribault	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.48	0	0.4	0	0	-0.4	200612	R1.5	NSP-MN DEPRECIATION BLENDING	560133	0	MN01-344000-Generators-W Faribault	560133	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344045-Generators-Blaz Star 1	10344Blazing Star I WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	3/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204504		NSPM-MN-EG002-D-19-161	1166398624	0	MN01-344045-Generators-Blaz Star 1	63944894	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	272947908.3	273628900.4
56	NSP-Minnesota	MN01-344045-Generators-Border Wind	10344Border WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.066	0	0	-0.066	204012		NSPM-ND-Elec-PU-18-228	836216230	0	MN01-344045-Generators-Border Wind	63944785	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	207398012.5	207800470.1
56	NSP-Minnesota	MN01-344045-Generators-Crtny Wind	10344Courtenay WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.069	0	0	-0.069	204111		NSPM-ND-Elec-PU-17-020	989834358	0	MN01-344045-Generators-Crtny Wind	63944842	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	261931248.1	261931248.1
56	NSP-Minnesota	MN01-344045-Generators-Foxtail WF	10344Foxtail WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	2/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.064	0	0	-0.064	204412		Specific filing	1166408217	0	MN01-344045-Generators-Foxtail WF	63944897	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	211967568.6	205054444
56	NSP-Minnesota	MN01-344045-Generators-Gr Meadow WF	10344Grand Meadow	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203311		NSPM-ND-C-PU-12-813	50907809	0	MN01-344045-Generators-Gr Meadow WF	49750563	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	182852556.8	182852556.8
56	NSP-Minnesota	MN01-344045-Generators-Heron Lak WF	10344Heron Lake WF	INVALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	55023903	0	MN01-344045-Generators-Heron Lak WF	49750570	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344045-Generators-Lk Benton WF	10344Lake Benton WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204411		NSPM-MN-EG002-D-19-161	1166408221	0	MN01-344045-Generators-Lk Benton WF	63944899	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	114019494	114088479
56	NSP-Minnesota	MN01-344045-Generators-Merricour WF	10344Merricourt WF	INVALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	55023852	0	MN01-344045-Generators-Merricour WF	49750569	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-344045-Generators-Nobles WF	10344Nobles	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203511		NSPM-ND-C-PU-12-813	55023799	0	MN01-344045-Generators-Nobles WF	49750568	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	471541459.7	471541459.7
56	NSP-Minnesota	MN01-344045-Generators-Pleasant V	10344Pleasant Valley WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204012			830447615	0	MN01-344045-Generators-Pleasant V	63944770	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	263617953.8	263617953.8
56	NSP-Minnesota	MN01-344045-Generators-Stoneray WF	10344Stoneray WF	INVALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0			NSP-MN DEPRECIATION BLENDING	55023952	0	MN01-344045-Generators-Stoneray WF	49750571	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-345000-Accessy Eq-Angus Anson	10345Angus C. Anson - 2 & 3	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.044	0	0	-0.044	203812	R1.5	NSPM-ND-C-PU-12-813	560134	0	MN01-345000-Accessy Eq-Angus Anson	560134	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	3570830.52	3570830.52
56	NSP-Minnesota	MN01-345000-Accessy Eq-Angus Anson4	10345Angus C. Anson - 4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.045	0	0	-0.045	203812		NSPM-ND-C-PU-12-813	24744635	0	MN01-345000-Accessy Eq-Angus Anson4	20936952	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	4933754.02	4933754.02
56	NSP-Minnesota	MN01-345000-Accessy Eq-Black Dog #5	10345Black Dog 5	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.025	0	0	-0.025	203112	R1.5	NSPM-ND-C-PU-12-813	8333810	0	MN01-345000-Accessy Eq-Black Dog #5	620721	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	27873918.19	27873918.19
56	NSP-Minnesota	MN01-345000-Accessy Eq-Black Dog #6	10345Black Dog 6	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	205803			1568391577	0	MN01-345000-Accessy Eq-Black Dog #6	63945150	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	10978423.62	10978423.62
56	NSP-Minnesota	MN01-345000-Accessy Eq-Blue Lake	10345Blue Lake 1-4	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.119	0	0	-0.119	201212	R1.5	NSPM-ND-C-PU-12-813	560135	0	MN01-345000-Accessy Eq-Blue Lake	560135	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1508867.81	1508867.81
56	NSP-Minnesota	MN01-345000-Accessy Eq-Blue Lake7&8	10345Blue Lake 7&8	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.052	0	0	-0.052	203505		NSPM-ND-C-PU-12-813	24744833	0	MN01-345000-Accessy Eq-Blue Lake7&8	20936955	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	7902569.42	7902569.42
56	NSP-Minnesota	MN01-345000-Accessy Eq-Granite City	10345Granite City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.388	0	0	-0.388	201312	R1.5	NSPM-ND-C-PU-12-813	560136	0	MN01-345000-Accessy Eq-Granite City	560136	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	14352.01	14352.01
56	NSP-Minnesota	MN01-345000-Accessy Eq-High BridgeM	10345High Bridge - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.031	0	0	-0.031	205305		NSPM-ND-C-PU-12-813	13650176	0	MN01-345000-Accessy Eq-High BridgeM	620890	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	52014325.93	52014325.93
56	NSP-Minnesota	MN01-345000-Accessy Eq-Inver Hills	10345Inver Hills	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.11	0	0	-0.11	202612	R1.5	NSPM-ND-C-PU-12-813	560137	0	MN01-345000-Accessy Eq-Inver Hills	560137	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	4309713.32	4309713.32
56	NSP-Minnesota	MN01-345000-Accessy Eq-Key City	10345Key City	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0.386	0	0	-0.386	201412	R1.5	NSPM-ND-C-PU-12-813	560138	0	MN01-345000-Accessy Eq-Key City	560138	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	-0.23	-0.23
56	NSP-Minnesota	MN01-345000-Accessy Eq-RiversideM	10345Riverside - Other	VALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.05	0	0	-0.05	204902		NSPM-ND-C-PU-12-813	13650198	0	MN01-345000-Accessy Eq-RiversideM	620895	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	40339753.8	40339753.8
56	NSP-Minnesota	MN01-345000-Accessy Eq-W Faribault	10345West Faribault	INVALID	Electric Other Production Plant	Electric Production	Other Production	12/1/2019 0:00	6	USED	0.5	End of Life	0.48	0	0.4	0	0	-0.4	200612	R1.5	NSP-MN DEPRECIATION BLENDING	560139	0	MN01-345000-Accessy Eq-W Faribault	560139	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-345045-Accessy Eq-Blaz Star 1	10345Blazing Star I WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	5/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204504		NSPM-MN-EG002-D-19-161	2201546759	0	MN01-345045-Accessy Eq-Blaz Star 1	63945296	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	10307802.68	10333520.16
56	NSP-Minnesota	MN01-345045-Accessy Eq-Border Wind	10345Border WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.066	0	0	-0.066	204012		NSPM-ND-Elec-PU-18-228	836216233	0	MN01-345045-Accessy Eq-Border Wind	63944786	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	34794648.9	34794648.9
56	NSP-Minnesota	MN01-345045-Accessy Eq-Crtny Wind	10345Courtenay WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.069	0	0	-0.069	204111		NSPM-ND-Elec-PU-17-020	989837705	0	MN01-345045-Accessy Eq-Crtny Wind	63944843	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	9591089.2	9591089.2
56	NSP-Minnesota	MN01-345045-Accessy Eq-Foxtail WF	10345Foxtail WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	2/1/2020 0:00	6	USED	0.5	End of Life	0	0	0.064	0	0	-0.064	204412		Specific filing	2181443625	0	MN01-345045-Accessy Eq-Foxtail WF	63945288	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-345045-Accessy Eq-Gr Meadow WF	10345Grand Meadow	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203311		NSPM-ND-C-PU-12-813	54738846	0	MN01-345045-Accessy Eq-Gr Meadow WF	49750566	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	12064305.44	12064305.44
56	NSP-Minnesota	MN01-345045-Accessy Eq-Heron Lak WF	10345Heron Lake WF	INVALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0				71856563	0	MN01-345045-Accessy Eq-Heron Lak WF	63944300	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-345045-Accessy Eq-Lk Benton WF	10345Lake Benton WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204411		NSPM-MN-EG002-D-19-161	2154435549	0	MN01-345045-Accessy Eq-Lk Benton WF	63945276	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	10953020.76	10959647.64
56	NSP-Minnesota	MN01-345045-Accessy Eq-Merricour WF	10345Merricourt WF	INVALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0				71856583	0	MN01-345045-Accessy Eq-Merricour WF	63944301	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN01-345045-Accessy Eq-Nobles WF	10345Nobles	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.087	0	0	-0.087	203511		NSPM-ND-C-PU-12-813	71856584	0	MN01-345045-Accessy Eq-Nobles WF	63944302	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	29938414.25	29938414.25
56	NSP-Minnesota	MN01-345045-Accessy Eq-Pleasant V	10345Pleasant Valley WF	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0.085	0	0	-0.085	204012			830447661	0	MN01-345045-Accessy Eq-Pleasant V	63944771	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	42507679.11	42507679.11
56	NSP-Minnesota	MN01-345045-Accessy Eq-Stoneray WF	10345Stoneray WF	INVALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0				71856585	0	MN01-345045-Accessy Eq-Stoneray WF	63944303	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0

56	NSP-Minnesota	MN01-347000-Oth Prod ARC-Nobles	#N/A	VALID	Electric Other Production Plant	Electric Production	Wind Production	1/1/2016 0:00	6	USED	1	SL	0	0	0	0	0	0			
56	NSP-Minnesota	MN01-347000-Oth Prod ARC-Pl. Valley	#N/A	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2015 0:00	6	USED	1	SL	0	0	0	0	0	0			
56	NSP-Minnesota	MN01-347000-Oth Prod ARC-Small Pekg	#N/A	INVALID	Electric Other Production Plant	Electric Production	Other Production	1/1/2016 0:00	6	USED	1	SL	0	0	0	0	0	0			
56	NSP-Minnesota	MN01-348010-Other Prod Fuel HldWind	10348010Fuel Storage	VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	End of Life	0	0	0	0	0	0	202312		
56	NSP-Minnesota	MN01-390000-Str & Impr	#N/A	INVALID	Electric General Plant	Electric Production	Electric Gen Building & Improvement	12/1/2019 0:00	6	USED	0.5	Monthly	0.022224	0	0	0	0	0			O4
56	NSP-Minnesota	MN01-Monti EPU Loss Depr Adj	Monti EPUMonti EPU	VALID	Electric Nuclear Production Plant	Electric Production	Nuclear Production	1/1/2016 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN01-Sherco 1&2 Depr Acceleration	Sherco 1/2 ND AccelerationSherco 1/2 ND Acceleration	VALID	Electric Steam Production Plant	Electric Production	Steam Production	1/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-10102000-Trn Pur & Sold	#N/A	INVALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-10182370-Elec Trans NSC	#N/A	VALID	Electric Transmission Plant	Pension Benefits Non-Service Costs	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.016365	0	0	0	0	0			
56	NSP-Minnesota	MN02-10182371-Trans Land NSC	#N/A	VALID	Electric Transmission Plant	Pension Benefits Non-Service Costs	Electric Transmission	8/1/2017 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-10182380- Trans Easmnts NSC	#N/A	VALID	Electric Transmission Plant	Pension Benefits Non-Service Costs	Electric Transmission	8/1/2017 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-10253050-Trans Sub-ASK-PF AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MERP	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.017713	0	0	0	0	0		677	
56	NSP-Minnesota	MN02-10253050-Trans Sub-HBR-PF AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MERP	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.017713	0	0	0	0	0		677	
56	NSP-Minnesota	MN02-10253050-Trans Sub-MNV-PF AFDC	#N/A	INVALID	Electric Transmission Plant	Pre-Funded AFUDC-MERP	Electric Transmission	12/1/2019 0:00	6	USED	0.5	Monthly	0.017708	0	0	0	0	0		678	
56	NSP-Minnesota	MN02-10253051-Trans Sub-TCR-MN AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.017713	0	0	0	0	0		677	
56	NSP-Minnesota	MN02-10253051-Trans Sub-TCR-MN WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.017713	0	0	0	0	0		677	
56	NSP-Minnesota	MN02-10253052-Trans Sub-MISO-PFAFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MISO	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015781	0	0	0	0	0		760	
56	NSP-Minnesota	MN02-10253052-Trans Sub-MISO-WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MISO	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015781	0	0	0	0	0		760	
56	NSP-Minnesota	MN02-10253053-Trans Sub-RES-PF AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-RES	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.017713	0	0	0	0	0		677	
56	NSP-Minnesota	MN02-10253054-Trans Sub-TCR-SD AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015501	0	0	0	0	0		774	
56	NSP-Minnesota	MN02-10253054-Trans Sub-TCR-SD WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015501	0	0	0	0	0		774	
56	NSP-Minnesota	MN02-10253056-Trans Sub-TCR-ND AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015781	0	0	0	0	0		760	
56	NSP-Minnesota	MN02-10253056-Trans Sub-TCR-ND WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015781	0	0	0	0	0		760	
56	NSP-Minnesota	MN02-10253060-Tran Line-HBR-PF AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MERP	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015838	0	0	0	0	0		758	
56	NSP-Minnesota	MN02-10253061-Tran Line-TCR-PF AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015838	0	0	0	0	0		758	
56	NSP-Minnesota	MN02-10253061-Tran Line-TCR-PF WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015838	0	0	0	0	0		758	
56	NSP-Minnesota	MN02-10253062-Tran Line-MISO-PFAFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MISO	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.014743	0	0	0	0	0		814	
56	NSP-Minnesota	MN02-10253062-Tran Line-MISO-WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-MISO	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.014743	0	0	0	0	0		814	
56	NSP-Minnesota	MN02-10253063-Tran Line-RES-PF AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-RES	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015838	0	0	0	0	0		758	
56	NSP-Minnesota	MN02-10253064-Tran Line-TCR-SD AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.014552	0	0	0	0	0		825	
56	NSP-Minnesota	MN02-10253064-Tran Line-TCR-SD WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.014552	0	0	0	0	0		825	
56	NSP-Minnesota	MN02-10253066-Tran Line-TCR-ND AFDC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.014743	0	0	0	0	0		814	
56	NSP-Minnesota	MN02-10253066-Tran Line-TCR-ND WICC	#N/A	VALID	Electric Transmission Plant	Pre-Funded AFUDC-TCR	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.014743	0	0	0	0	0		814	
56	NSP-Minnesota	MN02-114000-Acquisition Adjustment	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Acquisition Adjustment	1/1/2020 0:00	6	USED	1	End of Life	0	0	0	0	0	0	203908		
56	NSP-Minnesota	MN02-303004-Sfwr-General A	#N/A	INVALID	Electric Intangible Plant	Electric Transmission	Electric Software	1/1/2020 0:00	6	USED	1	SL	0	0	0	0	0	0		60	
56	NSP-Minnesota	MN02-350001-Fee Land	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-350002-Land Rights	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-350002-Land Rights BLM 30YR	#N/A	INVALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.033333	0	0	0	0	0			
56	NSP-Minnesota	MN02-350011-Fee Land Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-350012-Land Rights-Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352000-Str & Impr	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.013022	0	0	0	0	0			R5
56	NSP-Minnesota	MN02-352000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352010-Str & Impr Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.013022	0	0	0	0	0			R5
56	NSP-Minnesota	MN02-352010-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352010-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352010-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352010-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-352045-Str Imp-Wind	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.013022	0	0	0	0	0			R5
56	NSP-Minnesota	MN02-353000-Station Equipment	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.016052	0.001605	0.1	0	0	-0.1			R2
56	NSP-Minnesota	MN02-353000-Station Equipment 104	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.016052	0.001605	0.1	0	0	-0.1			R2
56	NSP-Minnesota	MN02-353000-Station Equipment 105	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353010-Station Equip Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.016052	0.001605	0.1	0	0	-0.1			R2
56	NSP-Minnesota	MN02-353010-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353010-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353010-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353010-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-353045-Station Equip-Wind	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.016052	0.001605	0.1	0	0	-0.1			R2
56	NSP-Minnesota	MN02-354000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354000-Towers & Fixtures	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.010352	0.003623	0.35	0	0	-0.35			R4
56	NSP-Minnesota	MN02-354010-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354010-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354010-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354010-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-354010-Towers & Fixtures-Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.010352	0.003623	0.35	0	0	-0.35			R4
56	NSP-Minnesota	MN02-354045-Towers & Fixtures-Wind	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.010352	0.003623	0.35	0	0	-0.35			R4
56	NSP-Minnesota	MN02-355000-Poles & Fixtures	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.015183	0.005314	0.35	0	0	-0.35			R2
56	NSP-Minnesota	MN02-355000-Poles & Fixtures 104	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.015183	0.005314	0.35	0	0	-0.35			R2
56	NSP-Minnesota	MN02-355000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355010-Poles & Fixtures-Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.015183	0.005314	0.35	0	0	-0.35			R2
56	NSP-Minnesota	MN02-355010-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355010-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355010-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355010-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-355045-Poles & Fixtures-Wind	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.015183	0.005314	0.35	0	0	-0.35			R2
56	NSP-Minnesota	MN02-356000-OH Conductors	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.014553	0.004366	0.3	0	0	-0.3			R1
56	NSP-Minnesota	MN02-356000-OH Conductors 104	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.014553	0.004366	0.3	0	0	-0.3			R1
56	NSP-Minnesota	MN02-356000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356010-OH Conductors-Prod	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.014553	0.004366	0.3	0	0	-0.3			R1
56	NSP-Minnesota	MN02-356010-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356010-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356010-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356010-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-356045-OH Conductors-Wind	#N/A	VALID	Electric Transmission Plant	Electric Transmission (TSG)	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.014553	0.004366	0.3	0	0	-0.3			R1
56	NSP-Minnesota	MN02-357000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-357000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-357000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-357000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-357000-UG Conduit	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.012239	0	0	0	0	0			R4
56	NSP-Minnesota	MN02-358000-Theo Res Depr MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-358000-Theo Res Depr WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-358000-Theo Res MN	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-358000-Theo Res WI I/A	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN02-358000-UG Conductors	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2020 0:00	6	USED	0.5	Monthly	0.016716	0	0	0	0	0			R2
56	NSP-Minnesota	MN02-359100-Trans ARC-Misc.	#N/A	VALID	Electric Transmission Plant	Electric Transmission	Electric Transmission	1/1/2014 0:00	6	USED	1	SL	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-10182370-Elec Dist NSC	#N/A	VALID	Electric Distribution Plant	Pension Benefits Non-Service Costs	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.023092	0	0	0	0	0			
56	NSP-Minnesota	MN03-10182371- Elec Dist Land NSC	#N/A	VALID	Electric Distribution Plant	Pension Benefits Non-Service Costs	Electric Distribution	8/1/2017 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land 105	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land 105-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2013 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land 105-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land 105-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2014 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2013 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360001-Fee Land-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360002-Land Rights	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360002-Land Rights-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2013 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360002-Land Rights-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360002-Land Rights-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360011-Fee Land Prod	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360011-Fee Land Prod-MN	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	1/1/2013 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360011-Fee Land Prod-ND	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-360011-Fee Land Prod-SD	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361000-Str & Impr	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2015 0:00	6	USED	0.5	Monthly	0.021396	0.007488	0.35	0	0.05	-0.3			R1
56	NSP-Minnesota	MN03-361000-Str & Impr 104	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.021396	0.007488	0.35	0	0.05	-0.3			R1
56	NSP-Minnesota	MN03-361000-Str & Impr 104-MN	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	0.5	Monthly	0.016667	0.005	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361000-Str & Impr 104-ND	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.017746	0.005324	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361000-Str & Impr 104-SD	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.015992	0.004797	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361000-Str & Impr-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.015995	0.004798	0.3	0	0	-0.3			R2.5
56	NSP-Minnesota	MN03-361000-Str & Impr-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.017746	0.005324	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361000-Str & Impr-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.015992	0.004797	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361000-Str & Impr-SD-105	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	4/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361000-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361000-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361010-Str & Impr Prod	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.021396	0.007488	0.35	0	0.05	-0.3			R1
56	NSP-Minnesota	MN03-361010-Str & Impr Prod-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.015995	0.004798	0.3	0	0	-0.3			R2.5
56	NSP-Minnesota	MN03-361010-Str & Impr Prod-ND	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.017746	0.005324	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361010-Str & Impr Prod-SD	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.015992	0.004797	0.3	0	0	-0.3		720	R3
56	NSP-Minnesota	MN03-361010-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361010-Theo Res Depr WI I/A	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361010-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-361010-Theo Res WI I/A	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-362000-Station Equip 104-MN	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2018 0:00	6	USED	0.5	Monthly	0.01896	0.00474	0.25	0	0	-0.25			R2
56	NSP-Minnesota	MN03-362000-Station Equip 104-ND	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.018837	0.003768	0.2	0	0	-0.2		660	R1.5
56	NSP-Minnesota	MN03-362000-Station Equip 104-SD	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.017515	0.003503	0.2	0	0	-0.2		660	R1.5
56	NSP-Minnesota	MN03-362000-Station Equipment	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.025169	0.003775	0.15	0	0.05	-0.1			R1
56	NSP-Minnesota	MN03-362000-Station Equipment 104	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.025169	0.003775	0.15	0	0.05	-0.1			R1
56	NSP-Minnesota	MN03-362000-Station Equipment-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.018486	0.004621	0.25	0	0	-0.25			R2
56	NSP-Minnesota	MN03-362000-Station Equipment-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.018837	0.003768	0.2	0	0	-0.2		660	R1.5
56	NSP-Minnesota	MN03-362000-Station Equipment-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.017515	0.003503	0.2	0	0	-0.2		660	R1.5
56	NSP-Minnesota	MN03-362000-Station Equip-SD-105	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	4/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-362000-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-362000-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0			
56	NSP-Minnesota	MN03-362010-Station Equip Prod	#N/A	INVALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.025169	0.003775	0.15	0	0.05	-0.1			R1
56	NSP-Minnesota	MN03-362010-Station Equip Prod-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.018486	0.004621	0.25	0	0	-0.25			R2
56	NSP-Minnesota	MN03-362010-Station Equip Prod-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.018837	0.003768	0.2	0	0	-0.2		660	R1.5
56	NSP-Minnesota	MN03-362010-Station Equip Prod-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution (DSG)	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.017515	0.003503	0.2	0	0	-0.2		660	R1.5

56	NSP-Minnesota	MN03-362010-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341394290	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-362010-Theo Res Depr WI I/A	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1344932758	0	MN-Theoretical Reserve Depr	63945132	10800197	40300197	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-362010-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564844401	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-362010-Theo Res WI I/A	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882756	0	MN-Theoretical Reserve Amort	63944647	10800199	40300199	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-363000-Energy Storage Equip-MN	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	9/1/2016 0:00	6	USED	0.5	Monthly	0.07100592	0	0	0	0	0			14.08333		869411483	0	MN03-363000-Energy Storage Equip-MN	63944798	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-363000-Energy Storage Equip-ND	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	9/1/2016 0:00	6	USED	0.5	Monthly	0.07100592	0	0	0	0	0			14.08333		869623093	0	MN03-363000-Energy Storage Equip-ND	63944801	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-363000-Energy Storage Equip-SD	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	9/1/2016 0:00	6	USED	0.5	Monthly	0.07100592	0	0	0	0	0			14.08333		869623902	0	MN03-363000-Energy Storage Equip-SD	63944802	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-364000-Poles & Fixtures	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.024357	0.023139	0.95	0	0.05	-0.9		R1.5		NSP-MN DEPRECIATION BLENDING	560164	0	MN03-364000-Poles & Fixtures	560164	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-364000-Poles & Fixtures-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.021248	0.025498	1.2	0	0	-1.2		R1	47	NSPM-MN-TD&G-EG002-D-19-490	59355130	0	MN03-364000-Poles & Fixtures-MN	55511146	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	435840179.1	443289555.5
56	NSP-Minnesota	MN03-364000-Poles & Fixtures-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.023515	0.023516	1	0	0	-1	528	R1	44	NSPM-ND-C-PU-12-813	59355166	0	MN03-364000-Poles & Fixtures-ND	55511147	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	18145439.18	18177082.7
56	NSP-Minnesota	MN03-364000-Poles & Fixtures-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.02166	0.02166	1	0	0	-1	528	R1	44	NSPM-SD-D-EL14-058	59355197	0	MN03-364000-Poles & Fixtures-SD	55511148	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	49802685.21	50259425.99
56	NSP-Minnesota	MN03-364000-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341394294	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-364000-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564844402	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-365000-OH Conductors	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.026531	0.010612	0.4	0	0.1	-0.3		R1		NSP-MN DEPRECIATION BLENDING	560165	0	MN03-365000-OH Conductors	560165	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-365000-OH Conductors-105-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2014 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0		R1		NSP-MN DEPRECIATION BLENDING	60150135	0	MN03-366000-UG Conduit 105	49750526	10800107	40300107	YES	41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-365000-OH Conductors-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.025619	0.006405	0.25	0	0	-0.25		L0	39	NSPM-MN-TD&G-EG002-D-19-490	59355228	0	MN03-365000-OH Conductors-MN	55511149	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	458617777.4	462914598.7
56	NSP-Minnesota	MN03-365000-OH Conductors-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.026172	0.005235	0.2	0	0	-0.2	468	L0	39	NSPM-ND-C-PU-12-813	59355377	0	MN03-365000-OH Conductors-ND	55511150	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	22694668.41	22750930.21
56	NSP-Minnesota	MN03-365000-OH Conductors-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.024793	0.004959	0.2	0	0	-0.2	468	L0	39	NSPM-SD-D-EL14-058	59355411	0	MN03-365000-OH Conductors-SD	55511151	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	52549494.19	52609897.3
56	NSP-Minnesota	MN03-365000-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341394319	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-365000-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564844403	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341394325	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564844404	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-UG Conduit	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.02	0	0	0	0	0		R3		NSP-MN DEPRECIATION BLENDING	560166	0	MN03-366000-UG Conduit	560166	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-UG Conduit 105	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2014 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0		R1		NSP-MN DEPRECIATION BLENDING	51519311	0	MN03-366000-UG Conduit 105	49750526	10800107	40300107	YES	41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-UG Conduit 105-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2014 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0		R3			59356598	0	MN03-366000-UG Conduit 105-MN	55511155	10800107	40300107	YES	41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-UG Conduit 105-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0		R3			59356629	0	MN03-366000-UG Conduit 105-ND	55511156	10800107	40300107	YES	41106000	41107000	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-UG Conduit 105-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0		R3			59356664	0	MN03-366000-UG Conduit 105-SD	55511157	10800107	40300107	YES	41106000	41107000	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-366000-UG Conduit-MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2020 0:00	6	USED	0.5	Monthly	0.017896	0.003579	0.2	0	0	-0.2		R3	56	NSPM-MN-TD&G-EG002-D-19-490	59355448	0	MN03-366000-UG Conduit-MN	55511152	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	305750850.1	309403941.6
56	NSP-Minnesota	MN03-366000-UG Conduit-ND	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.020309	0.002031	0.1	0	0	-0.1	624	R3	52	NSPM-ND-C-PU-12-813	59355479	0	MN03-366000-UG Conduit-ND	55511153	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	7338812.5	7344714.59
56	NSP-Minnesota	MN03-366000-UG Conduit-SD	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	3/1/2018 0:00	6	USED	0.5	Monthly	0.01783	0.001783	0.1	0	0	-0.1	624	R3	52	NSPM-SD-D-EL14-058	59355510	0	MN03-366000-UG Conduit-SD	55511154	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	19599825.85	19642931.34
56	NSP-Minnesota	MN03-367000-Theo Res Depr MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341395900	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-367000-Theo Res MN	#N/A	VALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564844405	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN03-367000-UG Conductor	#N/A	INVALID	Electric Distribution Plant	Electric Distribution	Electric Distribution	1/1/2009 0:00	6	USED	0.5	Monthly	0.022857	0	0	0	0.2	0.2		S1		NSP-MN DEPRECIATION BLENDING	560167	0	MN03-367000-UG Conductor	560167	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0

#	Company	Asset	Location	Lookup	Status	Plant	Function	Sub-function	In-Service Date	Depreciation Blending	ID	%	Description	Asset ID	Account	Account	Flag		Account	Account			Gain/Loss	Basis	Treatment	Value	Value
56	NSP-Minnesota	MN04-397030-Load Mngmt-CPR		#N/A	VALID	Electric General Plant	Electric General	Electric General Other	1/1/2020 0:00	NSPM-ND-C-PU-12-813	63944334	99	MN04-397030-Load Mngmt-CPR	63944258	10800107	40300107	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	41423748.09	41315831.1
56	NSP-Minnesota	MN04-397040-Comm Eq-Smart Grd-CPR		#N/A	VALID	Electric General Plant	Electric General	Electric General Other	1/1/2020 0:00	NSPM-ND-C-PU-12-813	445871884	99	MN04-397040-Comm Eq-Smart Grid-CPR	63944594	10800107	40300107	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN04-398000-Misc Equip 2003		#N/A	INVALID	Electric General Plant	Electric General	Electric General Other	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	11167689	0	MN04-398000-Misc Equip 2003	620792	10800107	40300107	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN04-398000-Misc Equip 2006		#N/A	INVALID	Electric General Plant	Electric General	Electric General Other	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	31336208	0	MN04-398000-Misc Equip 2006	31336246	10800107	40300107	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN04-398000-Misc Equip-COR&SLVG		#N/A	VALID	Electric General Plant	Electric General	Electric General Other	8/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560646	0	MN04-398000-Misc Equip 1960	560646	10800107	40300107	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN04-398000-Misc Equip-CPR		#N/A	VALID	Electric General Plant	Electric General	Electric General Other	1/1/2020 0:00	NSPM-ND-C-PU-12-813	63944335	99	MN04-398000-Misc Equip-CPR	63944238	10800107	40300107	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	3619612.57	3619612.57
56	NSP-Minnesota	MN04-398000-Misc Equip-Theo Res MN		#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00		564882634	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN04-398000-MiscEq-Theo Res Depr MN		#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00		1341476039	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-20182370-6" Line-NSC		#N/A	INVALID	Gas Manufactured Production Plant	Pension Benefits Non-Service Costs	Gas Production and Gathering	8/1/2017 0:00		1292116835	0	MN05-20182370-6" Line-NSC	63945033	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-20182370-Grand Forks-NSC		#N/A	INVALID	Gas Manufactured Production Plant	Pension Benefits Non-Service Costs	Gas Production and Gathering	8/1/2017 0:00		1292116831	0	MN05-20182370-Grand Forks-NSC	63945029	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-20182370-Sibley-NSC		#N/A	VALID	Gas Manufactured Production Plant	Pension Benefits Non-Service Costs	Gas Production and Gathering	8/1/2017 0:00		1292116833	0	MN05-20182370-Sibley-NSC	63945031	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	-3478.45	-3478.45
56	NSP-Minnesota	MN05-20182370-Wescott-NSC		#N/A	INVALID	Gas Manufactured Production Plant	Pension Benefits Non-Service Costs	Gas Production and Gathering	11/1/2019 0:00		1292116834	0	MN05-20182370-Wescott-NSC	63945032	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-20182371-Non-Depr Intang NSC		#N/A	VALID	Gas Manufactured Production Plant	Pension Benefits Non-Service Costs	Gas Production and Gathering	8/1/2017 0:00		1292116836	0	MN05-20182371-Non-Depr Intang NSC	63945034	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-304001-Fee Land	20304Land		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560660	0	MN05-304001-Fee Land	560660	10800207	40300207	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	356015.49	356015.49
56	NSP-Minnesota	MN05-304002-Land Rights	20304Land Rights		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560661	0	MN05-304002-Land Rights	560661	11100240	40403241	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	34536.46	34536.46
56	NSP-Minnesota	MN05-305000-Str & Impr-105		#N/A	VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	4/1/2019 0:00		1817969743	0	MN05-305000-Str & Impr-105	63945237	10800207	40300207	YES		41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-305000-Str & Impr-Grand Forks	20305Grand Forks		INVALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	7/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560662	0	MN05-305000-Str & Impr-Grand Forks	560662	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-305000-Str & Impr-Maplewood	20305Maplewood		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560663	0	MN05-305000-Str & Impr-Maplewood	560663	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1611045.59	1611045.59
56	NSP-Minnesota	MN05-305000-Str & Impr-Sibley	20305Sibley		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2017 0:00	NSP-MN DEPRECIATION BLENDING	560664	0	MN05-305000-Str & Impr-Sibley	560664	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1090679.83	1090679.83
56	NSP-Minnesota	MN05-305000-Str & Impr-Sibley Dock	20305Sibley		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2017 0:00	NSP-MN DEPRECIATION BLENDING	560665	0	MN05-305000-Str & Impr-Sibley	560664	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	75797.52	75797.52
56	NSP-Minnesota	MN05-305000-Str & Impr-Wescott	20305Wescott		INVALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	11/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560666	0	MN05-305000-Str & Impr-Wescott	560666	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-311000-Liquefied Eq-105		#N/A	VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	4/1/2019 0:00		1817969777	0	MN05-311000-Liquefied Eq-105	63945238	10800207	40300207	YES		41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-311000-Liquefied Eq-6" Line	203116" Line		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	7/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560667	0	MN05-311000-Liquefied Eq-6" Line	560667	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1040.39	1040.39
56	NSP-Minnesota	MN05-311000-Liquefied Eq-Grand Fks	20311Grand Forks		INVALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	7/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560668	0	MN05-311000-Liquefied Eq-Grand Fks	560668	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-311000-Liquefied Eq-Maplewood	20311Maplewood		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560669	0	MN05-311000-Liquefied Eq-Maplewood	560669	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	3766754.5	3766754.5
56	NSP-Minnesota	MN05-311000-Liquefied Eq-Sibley	20311Sibley		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2017 0:00	NSP-MN DEPRECIATION BLENDING	560670	0	MN05-311000-Liquefied Eq-Sibley	560670	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	8682871.58	8682871.58
56	NSP-Minnesota	MN05-311000-Liquefied Eq-Sibley-Dck	20311Sibley		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2017 0:00	NSP-MN DEPRECIATION BLENDING	560671	0	MN05-311000-Liquefied Eq-Sibley	560670	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	792306.41	792306.41
56	NSP-Minnesota	MN05-311000-Liquefied Eq-Wescott	20311Wescott		INVALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	11/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560672	0	MN05-311000-Liquefied Eq-Wescott	560672	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-320000-Other Equip-105		#N/A	VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	4/1/2019 0:00		1817969780	0	MN05-320000-Other Equip-105	63945239	10800207	40300207	YES		41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-320000-Other Equip-Grand Fks	20320Grand Forks		INVALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	7/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560673	0	MN05-320000-Other Equip-Grand Fks	560673	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN05-320000-Other Equip-Maplewood	20320Maplewood		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560674	0	MN05-320000-Other Equip-Maplewood	560674	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	455629.43	455629.43
56	NSP-Minnesota	MN05-320000-Other Equip-Sibley	20320Sibley		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2017 0:00	NSP-MN DEPRECIATION BLENDING	560675	0	MN05-320000-Other Equip-Sibley	560675	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	578136.5	578136.5
56	NSP-Minnesota	MN05-320000-Other Equip-Sibley Dock	20320Sibley		VALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	1/1/2017 0:00	NSP-MN DEPRECIATION BLENDING	560676	0	MN05-320000-Other Equip-Sibley	560675	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	57841.66	57841.66
56	NSP-Minnesota	MN05-320000-Other Equip-Wescott	20320Wescott		INVALID	Gas Manufactured Production Plant	Gas Production	Gas Production and Gathering	11/1/2019 0:00	NSP-MN DEPRECIATION BLENDING	560677	0	MN05-320000-Other Equip-Wescott	560677	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN06-20182370 - Wescott - NSC		#N/A	VALID	Gas Other Storage Plant	Pension Benefits Non-Service Costs	Gas Storage	1/1/2018 0:00		1456381788	0	MN06-20182370 - Wescott - NSC	63945140	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	-517.81	-517.81
56	NSP-Minnesota	MN06-20182370-Wescott Misc-NSC		#N/A	INVALID	Gas Other Storage Plant	Pension Benefits Non-Service Costs	Gas Storage	1/1/2018 0:00		1456396011	0	MN06-20182370-Wescott Misc-NSC	63945141	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN06-20182370-Wescott Vapor-NSC		#N/A	INVALID	Gas Other Storage Plant	Pension Benefits Non-Service Costs	Gas Storage	1/1/2018 0:00		1456400988	0	MN06-20182370-Wescott Vapor-NSC	63945142	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN06-360001-Fee Land	20360Land		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	561435	0	MN06-360001-Fee Land	561435	10800207	40300207	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	349573.83	349573.83
56	NSP-Minnesota	MN06-360002-Land Rights	20360Land Rights		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560678	0	MN06-360002-Land Rights	560678	11100240	40403241	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	11264.26	11264.26
56	NSP-Minnesota	MN06-361000-Str & Impr-Wescott	20361Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560679	0	MN06-361000-Str & Impr-Wescott	560679	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	6456691.58	6456691.58
56	NSP-Minnesota	MN06-362000-Gas Holders-Wescott	20362Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560680	0	MN06-362000-Gas Holders-Wescott	560680	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	8260593.22	8260593.22
56	NSP-Minnesota	MN06-363000-Purificatn Eq-Delano	20363Delano		INVALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	561392	0	MN06-363000-Purificatn Eq-Delano	561392	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN06-363000-Purificatn Eq-Wescott	20363Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560681	0	MN06-363000-Purificatn Eq-Wescott	560681	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	985962.02	985962.02
56	NSP-Minnesota	MN06-363100-Liquefactn Eq-Wescott	20363.1Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560682	0	MN06-363100-Liquefactn Eq-Wescott	560682	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	3564676.47	3564676.47
56	NSP-Minnesota	MN06-363200-Vaporizing Eq-Wescott	20363.2Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560683	0	MN06-363200-Vaporizing Eq-Wescott	560683	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	9363388.59	9363388.59
56	NSP-Minnesota	MN06-363300-Compressor Eq-Wescott	20363.3Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560684	0	MN06-363300-Compressor Eq-Wescott	560684	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	23752052.26	23752052.26
56	NSP-Minnesota	MN06-363400-Regulating Eq-Wescott	20363.4Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560685	0	MN06-363400-Regulating Eq-Wescott	560685	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	73633.69	73633.69
56	NSP-Minnesota	MN06-363500-Other Equipmt-Wescott	20363.5Wescott		VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	1/1/2016 0:00	NSP-MN DEPRECIATION BLENDING	560686	0	MN06-363500-Other Equipmt-Wescott	560686	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	5016534.1	5016534.1
56	NSP-Minnesota	MN06-363600-Gas Other Storage ARC		#N/A	VALID	Gas Other Storage Plant	Gas Storage	Gas Storage	11/1/2016 0:00		987553550	100	MN06-363600-Gas Other Storage ARC	63944837	10800204	40301204	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	184681.82	184681.82
56	NSP-Minnesota	MN07-20182370-Gas Trans NSC		#N/A	VALID	Gas Transmission Plant	Pension Benefits Non-Service Costs	Gas Transmission	1/1/2020 0:00	NSC on Financial only	1292116839	0	MN07-20182370-Gas Trans NSC	63945037	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	-66128.24	-66393.63
56	NSP-Minnesota	MN07-365100-Fee Land		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	560687	0	MN07-365100-Fee Land	560687	10800207	40300207	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	629060.66	629060.66
56	NSP-Minnesota	MN07-365200-Land Rights		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	560688	0	MN07-365200-Land Rights	560688	11100240	40403241	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	878102.8	878102.8
56	NSP-Minnesota	MN07-365200-Land Rights BLM 10YR		#N/A	INVALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	42448913	0	MN07-365200-Land Rights BLM	41818962	11100240	40403241	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN07-365200-Land Rights BLM 30YR		#N/A	INVALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	42449088	0	MN07-365200-Land Rights BLM	41818962	11100240	40403241	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN07-366000-Str & Impr		#N/A	INVALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	560689	0	MN07-366000-Str & Impr	560689	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN07-366000-Str & Impr-MN		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2020 0:00	NSPM-MN-TD&G-EG002-D-19-490	488641441	0	MN07-366000-Str & Impr-MN	63944611	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	932906.53	932906.53
56	NSP-Minnesota	MN07-366000-Str & Impr-ND		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2020 0:00	NSPM-MN-TD&G-EG002-D-19-490	488641442	0	MN07-366000-Str & Impr-ND	63944612	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	135139.55	135139.55
56	NSP-Minnesota	MN07-367000-Mains Metallic		#N/A	INVALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	560690	0	MN07-367000-Mains Metallic	560690	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN07-367000-Mains Metallic-105		#N/A	INVALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	3/1/2014 0:00	NSP-MN DEPRECIATION BLENDING	45925440	0	MN07-367000-Mains Metallic-105	41819074	10800207	40300207	YES		41106000	41107000	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN07-367000-Mains Metallic-MN		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2020 0:00	NSPM-MN-TD&G-EG002-D-19-490	488641462	0	MN07-367000-Mains Metallic-MN	63944613	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	96488463.6	95575316.02
56	NSP-Minnesota	MN07-367000-Mains Metallic-ND		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2020 0:00	NSPM-MN-TD&G-EG002-D-19-490	488641490	0	MN07-367000-Mains Metallic-ND	63944614	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	2733508.56	2733508.56
56	NSP-Minnesota	MN07-369000-Regulating Eq		#N/A	INVALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2009 0:00	NSP-MN DEPRECIATION BLENDING	560691	0	MN07-369000-Regulating Eq	560691	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN07-369000-Regulating Eq-MN		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2020 0:00	NSPM-MN-TD&G-EG002-D-19-490	488641487	0	MN07-369000-Regulating Eq-MN	63944615	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	16337816.87	16337902.98
56	NSP-Minnesota	MN07-369000-Regulating Eq-ND		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	1/1/2020 0:00	NSPM-MN-TD&G-EG002-D-19-490	488641491	0	MN07-369000-Regulating Eq-ND	63944616	10800207	40300207	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	1109890.82	1109890.82
56	NSP-Minnesota	MN07-372000-GAS TRANS MAINS ARC		#N/A	VALID	Gas Transmission Plant	Gas Transmission	Gas Transmission	12/1/2014 0:00		680386181	100	MN07-37200-GAS TRANS MAINS ARC	63944707	10800204	40301204	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	220121.22	220121.22
56	NSP-Minnesota	MN08-20182370-Gas Dist NSC		#N/A	VALID	Gas Distribution Plant	Pension Benefits Non-Service Costs	Gas Distribution	1/1/2020 0:00	NSC on Financial only	1292116830	0	MN08-20182300-Gas Dist NSC	63945039	10800253	40300253	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	-1115262.1	-1681192.17

Northern States Power Company

Docket No. E125/___
Volume 8 - Interchange Agreement
Page 1005 of 1247

Document Accession #: 20240313-5122 Filed Date: 03/13/2024 PDF/A non-compatible

56	NSP-Minnesota	MN11-394000-Garage Eq 1965	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.066672	0	0	0	0	0		L0.5		NSP-MN DEPRECIATION BLENDING	561040	0	MN11-394000-Garage Eq 1965	561040	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394000-Garage Eq 1969	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.066672	0	0	0	0	0		L0.5		NSP-MN DEPRECIATION BLENDING	561044	0	MN11-394000-Garage Eq 1969	561044	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394000-Garage Eq 1971	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.066672	0	0	0	0	0		L0.5		NSP-MN DEPRECIATION BLENDING	561046	0	MN11-394000-Garage Eq 1971	561046	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394000-Garage Eq 2003	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.066672	0	0	0	0	0		L0.5		NSP-MN DEPRECIATION BLENDING	11167916	0	MN11-394000-Garage Eq 2003	620802	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394000-Garage Eq-COR&SLVG	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.066672	0	0	0	0	0		L0.5		NSP-MN DEPRECIATION BLENDING	561296	0	MN11-394000-Garage Eq 1958	561296	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394000-Garage Eq-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.068383	0	0	0	0	0		175	15	NSPM-ND-C-PU-12-813	63944321	99	MN11-394000-Garage Eq-CPR	63944140	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	5438203.21	5438203.21
56	NSP-Minnesota	MN11-394000-Garage Eq-Theo Res MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882523	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394000-Tools-Theo Res Depr MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341497503	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394010-HH Mtr Rdrs-COR&SLVG	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	8/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561077	0	MN11-394010-HH Mtr Rdrs 1989	561077	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-394010-HH Mtr Rdrs-CPR	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	5/1/2013 0:00	6	USED	0.5	RATE	0.200004	0	0	0	0	0		60			63944361	99	MN11-394010-HH Mtr Rdrs-CPR	63944253	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-395000-Lab Eq-Theo Res Depr MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341504203	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-395000-Lab Equip 2005	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.099996	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	20936631	0	MN11-395000-Lab Equip 2005	20936669	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-395000-Lab Equip-COR&SLVG	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	8/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561087	0	MN11-395000-Lab Equip 1977	561087	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-395000-Lab Equip-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.116061	0	0	0	0	0		103	10	NSPM-ND-C-PU-12-813	63944322	99	MN11-395000-Lab Equip-CPR	63944144	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-395000-Lab Equip-Theo Res MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882549	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-396000-POE Other-COR&SLVG	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	8/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561086	0	MN11-396000-POE Other 1996	561086	10800407	18400407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-396000-POE Other-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.085497	0	0	0	0	0		140	12	NSPM-ND-C-PU-12-813	63944323	99	MN11-396000-POE Other-CPR	63944237	10800407	18400407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	1051794.67	1243699.18
56	NSP-Minnesota	MN11-396000-POE Other-Theo Res MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882557	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-396000-POE-Theo Res Depr MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341508979	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397000-Comm Eq 1992	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.111108	0	0	0	0	0		L1		NSP-MN DEPRECIATION BLENDING	561105	0	MN11-397000-Comm Eq 1992	561105	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397000-Comm Eq 2002	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.111108	0	0	0	0	0		L1		NSP-MN DEPRECIATION BLENDING	7383372	0	MN11-397000-Comm Eq 2002	620573	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397000-Comm Eq-COR&SLVG	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	8/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561101	0	MN11-397000-Comm Eq 1986	561101	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397000-Comm Eq-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.119005	0	0	0	0	0		101	9	NSPM-ND-C-PU-12-813	63944305	99	MN11-397000-Comm Eq-CPR	63944278	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	148849.59	148937.47
56	NSP-Minnesota	MN11-397000-Comm Eq-Theo Res DeprMN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341508983	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397000-Comm Eq-Theo Res MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882661	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397010-2 Way-Theo Res Depr MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341509018	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397010-PBX-COR&SLVG	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	8/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561115	0	MN11-397010-PBX 1982	561115	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397010-PBX-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.120571	0	0	0	0	0		100	9	NSPM-ND-C-PU-12-813	63944300	99	MN11-397010-PBX-CPR	63944141	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	76870.05	76870.05
56	NSP-Minnesota	MN11-397010-Two Way-Theo Res MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882668	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397020-Comm Eq-AES-CPR	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	5/1/2013 0:00	6	USED	0.5	RATE	0.11111	0	0	0	0	0		109			101680765	99	MN11-397020-Comm Eq-AES-CPR	63944396	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397030-Comm Eq-EMS-CPR	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	5/1/2013 0:00	6	USED	0.5	RATE	0.11111	0	0	0	0	0		109			101680806	99	MN11-397030-Comm Eq-EMS-CPR	63944397	10800407	40300407	YES	0	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-397040-Comm Eq-Smart Grid-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.119005	0	0	0	0	0		101	9	NSPM-ND-C-PU-12-813	1064057224	99	MN11-397040-Comm Eq-Smart Grid-CPR	63945249	10800407	40300407	YES	0	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	1469128.67	1469128.67
56	NSP-Minnesota	MN11-398000-Misc Eq-Theo Res DeprMN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2017 0:00	6	USED	1	Monthly	0	0	0	0	0	0					1341509023	0	MN-Theoretical Reserve Depr	63945132	10800196	40300196	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-398000-Misc Equip 1964	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.066672	0	0	0	0	0		L0		NSP-MN DEPRECIATION BLENDING	561303	0	MN11-398000-Misc Equip 1964	561303	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-398000-Misc Equip 2010	#N/A	INVALID	Common General Plant	Common General	Common General Plant Other	1/1/2009 0:00	6	USED	0.5	Monthly	0.06667	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	60522179	0	MN11-398000-Misc Equip 2009	55510660	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-398000-Misc Equip-COR&SLVG	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	8/1/2016 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561134	0	MN11-398000-Misc Equip 1962	561134	10800407	40300407	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-398000-Misc Equip-CPR	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.072002	0	0	0	0	0		167	15	NSPM-ND-C-PU-12-813	63944340	99	MN11-398000-Misc Equip-CPR	63944232	10800407	40300407	YES	0	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	235608.17	235608.17
56	NSP-Minnesota	MN11-398000-Misc Equip-Theo Res MN	#N/A	VALID	Electric General Plant	Electric General	Electric General Other	12/1/2013 0:00	6	USED	1	Monthly	0	0	0	0	0	0					564882674	0	MN-Theoretical Reserve Amort	63944647	10800198	40300198	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-399100-ARC-Com Gen 414 Nicolle	#N/A	INVALID	Common General Plant	Common General	Common Gen Buildings & Improvements	1/1/2009 0:00	6	USED	1	SL	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	30774446	100	MN11-399100-ARC Com Gen 414 Nicolle	20936978	10800404	40301404	NO		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-399100-Gen ARC-Misc.	#N/A	VALID	Common General Plant	Common General	Common General Plant Other	12/1/2013 0:00	6	USED	1	SL	0	0	0	0	0	0					564856325	100	MN11-40399100-Gen ARC-Misc.	63944651	10800404	40301404	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	650434.55	650434.55
56	NSP-Minnesota	MN11-40182372-Cm Genl Bldg NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common Gen Buildings & Improvements	1/1/2020 0:00	6	USED	0.5	Monthly	0.020023	0	0	0	0	0				NSC on Financial only	1292116887	0	MN11-40182372-Cm Genl Bldg NSC	63945043	10800453	40300453	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	-11617.18	-11617.18
56	NSP-Minnesota	MN11-40182372-Str&Impr 401-LSD NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common Gen Buildings & Improvements	1/1/2020 0:00	6	USED	1	End of Life	0.068359	0	0	0	0	0	203104			NSC on Financial only	1292116790	0	MN11-40182372-Str&Impr 401-LSD NSC	63944990	10800453	40300453	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-40182372-Str&Impr LSD Bld NSC	#N/A	INVALID	Common General Plant	Pension Benefits Non-Service Costs	Common Gen Buildings & Improvements	8/1/2017 0:00	6	USED	1	End of Life	0	0	0	0	0	0	201606				1292116791	0	MN11-40182372-Str&Impr LSD Bld NSC	63944991	10800453	40300453	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN11-40182373- Cm Comm Eq NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.053411	0	0	0	0	0		143		NSC on Financial only	1292116888	99	MN11-40182373- Cm Comm Eq NSC	63945044	10800453	40300453	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-21816.84	-21816.84
56	NSP-Minnesota	MN11-40182374-Cm Genl Furniture NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.048242	0	0	0	0	0		252		NSC on Financial only	1292116889	99	MN11-40182374-Cm Genl Furniture NSC	63945045	10800453	40300453	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-1283.57	-1283.76
56	NSP-Minnesota	MN11-40182375-Cm Gen Network Eq NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.208323	0	0	0	0	0		61		NSC on Financial only	1292116892	99	MN11-40182375-Cm Gen Network Eq NSC	63945048	10800453	40300453	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-143373.29	-143384.06
56	NSP-Minnesota	MN11-40182376- Cm Genl Software NSC	#N/A	VALID	Common Intangible Plant	Pension Benefits Non-Service Costs	Common Software	1/1/2020 0:00	6	USED	1	RATE	0.160357	0	0	0	0	0		103	8	NSC on Financial only	1292116893	99	MN11-40182376- Cm Genl Software NSC	63945049	11100453	40500454	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-199673.08	-199826.01
56	NSP-Minnesota	MN11-40182377-Cm Genl Tls & Eq NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.067067	0	0	0	0	0		189		NSC on Financial only	1292116890	99	MN11-40182377-Cm Genl Tls & Eq NSC	63945046	10800453	40300453	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-439.95	-439.95
56	NSP-Minnesota	MN11-40182378-Cm Genl Transp Eq NSC	#N/A	VALID	Common General Plant	Pension Benefits Non-Service Costs	Common General Plant Other	1/1/2020 0:00	6	USED	0.5	RATE	0.078176	0	0	0	0	0		147		NSC on Financial only	1292116891	99	MN11-40182378-Cm Genl Transp Eq NSC	63945047	10800453	40300453	YES		42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	-569.38	-570.43
56	NSP-Minnesota	MN13-10182388-Nuclear Fuel NSC	#N/A	VALID	Nuclear Fuel	Pension Benefits Non-Service Costs	Nuclear Production	8/1/2017 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0					1292116841	0	MN13-10182388-Nuclear Fuel NSC	63945041	12005553	51800553	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	3531.06	7242.5
56	NSP-Minnesota	MN13-120200-NF Materials-Monti	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	11946142	0	MN13-120200-NF-In Stock-Monti	620857	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120200-NF Materials-Monti-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561415	0	MN01-120200-NF Materials-Monti	561415	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120200-NF Materials-PI	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	11946175	0	MN13-120200-NF-In Stock-PI	620858	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	69355588
56	NSP-Minnesota	MN13-120200-NF Materials-PI-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561416	0	MN01-120200-NF Materials-PI	561416	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120300-Reactor Eq-Monti	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	11946182	0	MN13-120300-NF-In Reactor-Monti	620859	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	238676382.2	238676382.2
56	NSP-Minnesota	MN13-120300-Reactor Eq-Monti-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561418	0	MN01-120300-Reactor Eq-Monti	561418	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120300-Reactor Eq-PI	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	11946184	0	MN13-120300-NF-In Reactor-PI	620860	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	318626687.8	318626687.8
56	NSP-Minnesota	MN13-120300-Reactor Eq-PI-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561417	0	MN01-120300-Reactor Eq-PI	561417	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120400-Turbogentr-Monti	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	11946187	0	MN13-120400-NF-Spent Fuel-Monti	620861	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	632084895.4	632084895.4
56	NSP-Minnesota	MN13-120400-Turbogentr-Monti-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561420	0	MN01-120400-Turbogentr-Monti	561420	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120400-Turbogentr-PI	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	11946193	0	MN13-120400-NF-Spent Fuel-PI	620862	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	1565741536	1565741536
56	NSP-Minnesota	MN13-120400-Turbogentr-PI-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	561419	0	MN01-120400-Turbogentr-PI	561419	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	NET	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-Monti-AFUDC	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14206962	0	MN13-120500-NF-Amort-Monti-AFUDC	620909	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-Monti-AFUDC-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14206862	0	MN01-120500-NF-Amort-Monti-AFUDC	620905	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-Monti-DOE	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14214576	0	MN13-120500-NF-Amort-Monti-DOE	620914	23200570	51800570	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-Monti-DOE-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14214535	0	MN01-120500-NF-Amort-Monti-DOE	620921	12005548	51800570	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-Monti-Mat.-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14214532	0	MN01-120500-NF-Amort-Monti-Material	620920	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-Monti-Material	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14214574	0	MN13-120500-NF-Amort-Monti-Material	620913	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-PI 1-AFUDC	#N/A	VALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14206964	0	MN13-120500-NF-Amort-PI 1-AFUDC	620910	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-PI 1-AFUDC-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14206846	0	MN01-120500-NF-Amort-PI 1-AFUDC	620908	12005548	51800548	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-PI 1-DOE	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	1/1/2009 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14214580	0	MN13-120500-NF-Amort-PI 1-DOE	620916	23200570	51800570	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	MN13-120500-NF-Amort-PI 1-DOE-1	#N/A	INVALID	Nuclear Fuel	Electric Production	Nuclear Production	12/1/2019 0:00	6	USED	0.5	Monthly	0	0	0	0	0	0				NSP-MN DEPRECIATION BLENDING	14214541	0	MN01-120500-NF-Amort-PI 1-DOE	620923	23200570	51800570	YES		42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0

56	NSP-Minnesota	ZMN01-34445-Generators-Mower WF	10344	Mower WF		VALID	Electric Other Production Plant	Electric Production	Wind Production	12/1/2019 0:00	6	USED	0.5	Monthly	0.08	0.0034	0.085	0	0	-0.085			1064146109	0	MN01-344045-Generators-Mower WF	63945250	10800107	40300107	YES	42101003	42102003	No	No	NO GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	ZMN02-10253053-Tran Sub-RER-PF AFDC			#N/A	INVALID	Electric Transmission Plant	Pre-Funded AFUDC-RES	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.017713	0	0	0	0	0	677	NSPM-MN-TD&G-EG002-D-19-490	1165774748	99	ZMN02-10253053-Tran Sub-RER-PF AFDC	63944880	25300164	40500164	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0
56	NSP-Minnesota	ZMN02-10253063-Tran Lin-RER-PF AFDC			#N/A	INVALID	Electric Transmission Plant	Pre-Funded AFUDC-RES	Electric Transmission	1/1/2020 0:00	6	USED	0.5	RATE	0.015838	0	0	0	0	0	758	NSPM-MN-TD&G-EG002-D-19-490	1165774773	99	ZMN02-10253063-Tran Lin-RER-PF-AFDC	63944881	25300164	40500164	YES	42101003	42102003	No	No	GAIN OR LOSS	GROSS	YES - SEPERATE	0	0

Utility Acct	Plant	Description	Concatenate
20304	Land	MN05-304001-Fee Land	20304Land
20304	Land Rights	MN05-304002-Land Rights	20304Land Rights
20305	Grand Forks	MN05-305000-Str & Impr-Grand Forks	20305Grand Forks
20305	Maplewood	MN05-305000-Str & Impr-Maplewood	20305Maplewood
20305	Sibley	MN05-305000-Str & Impr-Sibley	20305Sibley
20305	Sibley	MN05-305000-Str & Impr-Sibley Dock	20305Sibley
20305	Wescott	MN05-305000-Str & Impr-Wescott	20305Wescott
20311	6" Line	MN05-311000-Liquefied Eq-6" Line	203116" Line
20311	Grand Forks	MN05-311000-Liquefied Eq-Grand Fks	20311Grand Forks
20311	Maplewood	MN05-311000-Liquefied Eq-Maplewood	20311Maplewood
20311	Sibley	MN05-311000-Liquefied Eq-Sibley	20311Sibley
20311	Sibley	MN05-311000-Liquefied Eq-Sibley-Dck	20311Sibley
20311	Wescott	MN05-311000-Liquefied Eq-Wescott	20311Wescott
20320	Grand Forks	MN05-320000-Other Equip-Grand Fks	20320Grand Forks
20320	Maplewood	MN05-320000-Other Equip-Maplewood	20320Maplewood
20320	Sibley	MN05-320000-Other Equip-Sibley	20320Sibley
20320	Sibley	MN05-320000-Other Equip-Sibley Dock	20320Sibley
20320	Wescott	MN05-320000-Other Equip-Wescott	20320Wescott
20360	Land	MN06-360001-Fee Land	20360Land
20360	Land Rights	MN06-360002-Land Rights	20360Land Rights
20361	Wescott	MN06-361000-Str & Impr-Wescott	20361Wescott
20362	Wescott	MN06-362000-Gas Holders-Wescott	20362Wescott
20363	Delano	MN06-363000-Purificatn Eq-Delano	20363Delano
20363	Wescott	MN06-363000-Purificatn Eq-Wescott	20363Wescott
20363.1	Wescott	MN06-363100-Liquefactn Eq-Wescott	20363.1Wescott
20363.2	Wescott	MN06-363200-Vaporizing Eq-Wescott	20363.2Wescott
20363.3	Wescott	MN06-363300-Compressor Eq-Wescott	20363.3Wescott
20363.4	Wescott	MN06-363400-Regulating Eq-Wescott	20363.4Wescott
20363.5	Wescott	MN06-363500-Other Equipmt-Wescott	20363.5Wescott
10302	Hennepin Island	MN01-302001-Franchise-Hennepin Is	10302Hennepin Island
10330	Land	MN01-330001-Fee Land	10330Land
10330	Land Rights	MN01-330002-Land Rights	10330Land Rights
10330	Land Rights - Amortized	MN01-330002-Land Rights-Amortized	10330Land Rights - Amortized
10331	Hennepin Island	MN01-331000-Str & Impr-Hennepin Is	10331Hennepin Island
10331	Lower Dam	MN01-331000-Str & Impr-Lower Dam	10331Lower Dam
10331	St Croix Falls	MN01-331000-Str & Impr-St Croix Fls	10331St Croix Falls
10332	Hennepin Island	MN01-332000-Reservoirs-Hennepin Is	10332Hennepin Island
10332	Lower Dam	MN01-332000-Reservoirs-Lower Dam	10332Lower Dam
10332	St Croix Falls	MN01-332000-Reservoirs-St Croix Fls	10332St Croix Falls
10332	Upper Dam	MN01-332000-Reservoirs-Upper Dam	10332Upper Dam
10333	Hennepin Island	MN01-333000-Turb & Gen-Hennepin Is	10333Hennepin Island
10334	Hennepin Island	MN01-334000-Accessy Eq-Hennepin Is	10334Hennepin Island
10335	Hennepin Island	MN01-335000-Misc Pl Eq-Hennepin Is	10335Hennepin Island
10335	Upper Dam	MN01-335000-Misc Pl Eq-Upper Dam	10335Upper Dam
10302	Monticello	MN01-302002-Franchise-Monticello	10302Monticello
10302	Prairie Island	MN01-302002-Franchise-Prairie Islnd	10302Prairie Island
10320	Land	MN01-320001-Fee Land	10320Land
10320	Land Rights	MN01-320002-Land Rights	10320Land Rights
10321	Monticello	MN01-321000-Str & Impr-Monti	10321Monticello
10321	Monti Interim Storage	MN01-321000-Str & Impr-Monti-Casks	10321Monti Interim Storage
10321	Monticello	MN01-321000-Str & Impr-Monti-LE	10321Monticello
10321	Monticello	MN01-321000-Str & Impr-Monti-Tr Ctr	10321Monticello
10321	Prairie Island	MN01-321000-Str & Impr-PI	10321Prairie Island
10321	PI Interim Storage	MN01-321000-Str & Impr-PI Dry Casks	10321PI Interim Storage
10321	Prairie Island	MN01-321000-Str & Impr-PI-Trng Ctr	10321Prairie Island
10322	Monticello	MN01-322000-Reactor Eq-Monti	10322Monticello
10322	Monti Interim Storage	MN01-322000-Reactor Eq-Monti Casks	10322Monti Interim Storage
10322	Prairie Island	MN01-322000-Reactor Eq-PI	10322Prairie Island
10322	PI Interim Storage	MN01-322000-Reactor Eq-PI Dry Casks	10322PI Interim Storage
10323	Monticello	MN01-323000-Turbogentr-Monti	10323Monticello
10323	Prairie Island	MN01-323000-Turbogentr-PI	10323Prairie Island
10324	Monticello	MN01-324000-Accessy Eq-Monti	10324Monticello
10324	Monticello	MN01-324000-Accessy Eq-Monti-Trg Ct	10324Monticello
10324	Prairie Island	MN01-324000-Accessy Eq-PI	10324Prairie Island
10324	Prairie Island	MN01-324000-Accessy Eq-PI Trng Ctr	10324Prairie Island
10325	Monticello	MN01-325000-Misc Pl Eq-Monti	10325Monticello
10325	Monticello	MN01-325000-Misc Pl Eq-Monti-Trg Ct	10325Monticello
10325	Prairie Island	MN01-325000-Misc Pl Eq-PI	10325Prairie Island
10325	Prairie Island	MN01-325000-Misc Pl Eq-PI-Trng Ctr	10325Prairie Island
Monti EPU	Monti EPU	MN01-Monti EPU Loss Depr Adj	Monti EPUMonti EPU
10325	DCM	MN01-325001-DCM-Int-Monti-FM	10325DCM
10325	DCM	MN01-325001-DCM-Int-Monti-FW	10325DCM

10325	DCM	MN01-325001-DCM-Int-Monti-MN	10325DCM
10325	DCM	MN01-325001-DCM-Int-Monti-ND	10325DCM
10325	DCM	MN01-325001-DCM-Int-Monti-SD	10325DCM
10325	DCM	MN01-325001-DCM-Int-Monti-WI	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 1-FM	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 1-FW	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 1-MN	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 1-ND	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 1-SD	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 1-WI	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 2-FM	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 2-FW	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 2-MN	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 2-ND	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 2-SD	10325DCM
10325	DCM	MN01-325001-DCM-Int-PI 2-WI	10325DCM
10325	DCM	MN01-325002-DCM-Qual-Monti-FM	10325DCM
10325	DCM	MN01-325002-DCM-Qual-Monti-FW	10325DCM
10325	DCM	MN01-325002-DCM-Qual-Monti-MN	10325DCM
10325	DCM	MN01-325002-DCM-Qual-Monti-ND	10325DCM
10325	DCM	MN01-325002-DCM-Qual-Monti-SD	10325DCM
10325	DCM	MN01-325002-DCM-Qual-Monti-WI	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 1-FM	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 1-FW	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 1-MN	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 1-ND	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 1-SD	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 1-WI	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 2-FM	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 2-FW	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 2-MN	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 2-ND	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 2-SD	10325DCM
10325	DCM	MN01-325002-DCM-Qual-PI 2-WI	10325DCM
10325	DCM	MN01-325003-DCM-NQual-Monti-FM	10325DCM
10325	DCM	MN01-325003-DCM-NQual-Monti-FW	10325DCM
10325	DCM	MN01-325003-DCM-NQual-Monti-MN	10325DCM
10325	DCM	MN01-325003-DCM-NQual-Monti-ND	10325DCM
10325	DCM	MN01-325003-DCM-NQual-Monti-SD	10325DCM
10325	DCM	MN01-325003-DCM-NQual-Monti-WI	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 1-FM	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 1-FW	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 1-MN	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 1-ND	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 1-SD	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 1-WI	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 2-FM	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 2-FW	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 2-MN	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 2-ND	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 2-SD	10325DCM
10325	DCM	MN01-325003-DCM-NQual-PI 2-WI	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-Monti-FM	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-Monti-FW	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-Monti-MN	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-Monti-ND	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-Monti-SD	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-Monti-WI	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 1-FM	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 1-FW	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 1-MN	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 1-ND	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 1-SD	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 1-WI	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 2-FM	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 2-FW	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 2-MN	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 2-ND	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 2-SD	10325DCM
10325	DCM	MN01-325004-DCM-NQual LT-PI 2-WI	10325DCM
10340	Land	MN01-340001-Fee Land	10340Land
10340	Land Rights	MN01-340002-Land Rights	10340Land Rights
10341	Angus C. Anson - 2 & 3	MN01-341000-Str & Impr-Angus Anson	10341Angus C. Anson - 2 & 3

	10341	Angus C. Anson - 4	MN01-341000-Str & Impr-Angus Anson4	10341Angus C. Anson - 4
	10341	Black Dog 5	MN01-341000-Str & Impr-Black Dog #5	10341Black Dog 5
	10341	Black Dog 6	MN01-341000-Str & Impr-Black Dog #6	10341Black Dog 6
	10341	Blue Lake 1-4	MN01-341000-Str & Impr-Blue Lake	10341Blue Lake 1-4
	10341	Blue Lake 7&8	MN01-341000-Str & Impr-Blue Lake7&8	10341Blue Lake 7&8
	10341	Granite City	MN01-341000-Str & Impr-Granite City	10341Granite City
	10341	High Bridge - Other	MN01-341000-Str & Impr-High BridgeM	10341High Bridge - Other
	10341	Holland WF	MN01-341000-Str & Impr-Holland Wind	10341Holland WF
	10341	Inver Hills	MN01-341000-Str & Impr-Inver Hills	10341Inver Hills
	10341	Key City	MN01-341000-Str & Impr-Key City	10341Key City
	10341	Riverside - Other	MN01-341000-Str & Impr-RiversideM	10341Riverside - Other
	10341	West Faribault	MN01-341000-Str & Impr-W Faribault	10341West Faribault
	10342	Angus C. Anson - 2 & 3	MN01-342000-Fuel Holdr-Angus Anson	10342Angus C. Anson - 2 & 3
	10342	Angus C. Anson - 4	MN01-342000-Fuel Holdr-Angus Anson4	10342Angus C. Anson - 4
	10342	Black Dog 5	MN01-342000-Fuel Holdr-Black Dog #5	10342Black Dog 5
	10342	Black Dog 6	MN01-342000-Fuel Holdr-Black Dog #6	10342Black Dog 6
	10342	Blue Lake 1-4	MN01-342000-Fuel Holdr-Blue Lake	10342Blue Lake 1-4
	10342	Blue Lake 7&8	MN01-342000-Fuel Holdr-Blue Lake7&8	10342Blue Lake 7&8
	10342	Granite City	MN01-342000-Fuel Holdr-Granite City	10342Granite City
	10342	High Bridge - Other	MN01-342000-Fuel Holdr-High BridgeM	10342High Bridge - Other
	10342	Inver Hills	MN01-342000-Fuel Holdr-Inver Hills	10342Inver Hills
	10342	Key City	MN01-342000-Fuel Holdr-Key City	10342Key City
	10342	Riverside - Other	MN01-342000-Fuel Holdr-RiversideM	10342Riverside - Other
	10342	West Faribault	MN01-342000-Fuel Holdr-W Faribault	10342West Faribault
	10342	Wind Storage	MN01-342010-Fuel Holdr-Wind/Storage	10342Wind Storage
	10343	Riverside - Other	MN01-343000-Prime Movers-RiversideM	10343Riverside - Other
	10343	Black Dog 5	MN01-343000-PrimeMover-Black Dog #5	10343Black Dog 5
	10343	Black Dog 6	MN01-343000-PrimeMover-Black Dog #6	10343Black Dog 6
	10343	High Bridge - Other	MN01-343000-PrimeMover-High BridgeM	10343High Bridge - Other
	10344	Alliant Tech	MN01-344000-Generators-Alliant Tech	10344Alliant Tech
	10344	Angus C. Anson - 2 & 3	MN01-344000-Generators-Angus Anson	10344Angus C. Anson - 2 & 3
	10344	Angus C. Anson - 4	MN01-344000-Generators-Angus Anson4	10344Angus C. Anson - 4
	10344	Black Dog 5	MN01-344000-Generators-Black Dog #5	10344Black Dog 5
	10344	Black Dog 6	MN01-344000-Generators-Black Dog #6	10344Black Dog 6
	10344	Blue Lake 1-4	MN01-344000-Generators-Blue Lake	10344Blue Lake 1-4
	10344	Blue Lake 7&8	MN01-344000-Generators-Blue Lake7&8	10344Blue Lake 7&8
	10344	Granite City	MN01-344000-Generators-Granite City	10344Granite City
	10344	High Bridge - Other	MN01-344000-Generators-High BridgeM	10344High Bridge - Other
	10344	Holland WF	MN01-344000-Generators-Holland	10344Holland WF
	10344	Inver Hills	MN01-344000-Generators-Inver Hills	10344Inver Hills
	10344	Key City	MN01-344000-Generators-Key City	10344Key City
	10344	Lake Benton	MN01-344000-Generators-Lake Benton	10344Lake Benton
	10344	Mankato Energy Center	MN01-344000-Generators-MEC	10344Mankato Energy Center
	10344	Photo Voltaic	MN01-344000-Generators-Photovoltaic	10344Photo Voltaic
	10344	Riverside - Other	MN01-344000-Generators-RiversideM	10344Riverside - Other
	10344	United Health	MN01-344000-Generators-United Hlth	10344United Health
	10344	United Hospital	MN01-344000-Generators-United Hosp	10344United Hospital
	10344	West Faribault	MN01-344000-Generators-W Faribault	10344West Faribault
	10345	Angus C. Anson - 2 & 3	MN01-345000-Accessy Eq-Angus Anson	10345Angus C. Anson - 2 & 3
	10345	Angus C. Anson - 4	MN01-345000-Accessy Eq-Angus Anson4	10345Angus C. Anson - 4
	10345	Black Dog 5	MN01-345000-Accessy Eq-Black Dog #5	10345Black Dog 5
	10345	Black Dog 6	MN01-345000-Accessy Eq-Black Dog #6	10345Black Dog 6
	10345	Blue Lake 1-4	MN01-345000-Accessy Eq-Blue Lake	10345Blue Lake 1-4
	10345	Blue Lake 7&8	MN01-345000-Accessy Eq-Blue Lake7&8	10345Blue Lake 7&8
	10345	Granite City	MN01-345000-Accessy Eq-Granite City	10345Granite City
	10345	High Bridge - Other	MN01-345000-Accessy Eq-High BridgeM	10345High Bridge - Other
	10345	Inver Hills	MN01-345000-Accessy Eq-Inver Hills	10345Inver Hills
	10345	Key City	MN01-345000-Accessy Eq-Key City	10345Key City
	10345	Riverside - Other	MN01-345000-Accessy Eq-RiversideM	10345Riverside - Other
	10345	West Faribault	MN01-345000-Accessy Eq-W Faribault	10345West Faribault
	10346	Angus C. Anson - 2 & 3	MN01-346000-Pwr Plt Eq-Angus Anson	10346Angus C. Anson - 2 & 3
	10346	Angus C. Anson - 4	MN01-346000-Pwr Plt Eq-Angus Anson4	10346Angus C. Anson - 4
	10346	Black Dog 5	MN01-346000-Pwr Plt Eq-Black Dog #5	10346Black Dog 5
	10346	Black Dog 6	MN01-346000-Pwr Plt Eq-Black Dog #6	10346Black Dog 6
	10346	Blue Lake 1-4	MN01-346000-Pwr Plt Eq-Blue Lake	10346Blue Lake 1-4
	10346	Blue Lake 7&8	MN01-346000-Pwr Plt Eq-Blue Lake7&8	10346Blue Lake 7&8
	10346	Granite City	MN01-346000-Pwr Plt Eq-Granite City	10346Granite City
	10346	High Bridge - Other	MN01-346000-Pwr Plt Eq-High BridgeM	10346High Bridge - Other
	10346	Inver Hills	MN01-346000-Pwr Plt Eq-Inver Hills	10346Inver Hills
	10346	Key City	MN01-346000-Pwr Plt Eq-Key City	10346Key City
	10346	Riverside - Other	MN01-346000-Pwr Plt Eq-RiversideM	10346Riverside - Other
	10346	West Faribault	MN01-346000-Pwr Plt Eq-W Faribault	10346West Faribault
Sherco 3 Deferral		Sherco 3 Deferral	MN01-182300-Sherco 3 Depr Deferral	Sherco 3 DeferralSherco 3 Deferral

10182 Black Dog Remediation	MN01-182-Stm Blk Dg Remed Reg	10182Black Dog Remediation
10310 Land	MN01-310001-Fee Land	10310Land
10310 Land Rights	MN01-310002-Land Rights	10310Land Rights
10311 Black Dog	MN01-311000-Str & Impr-Black Dog	10311Black Dog
10311 Black Dog	MN01-311000-Str & Impr-Black Dog #2	10311Black Dog
10311 High Bridge - Steam	MN01-311000-Str & Impr-High Br #4	10311High Bridge - Steam
10311 High Bridge - Steam	MN01-311000-Str & Impr-High Bridge	10311High Bridge - Steam
10311 Allen S. King	MN01-311000-Str & Impr-King	10311Allen S. King
10311 MN Valley	MN01-311000-Str & Impr-MN Valley	10311MN Valley
10311 MN Valley	MN01-311000-Str & Impr-MN Vly Edike	10311MN Valley
10311 MN Valley	MN01-311000-Str & Impr-MN Vly Wdike	10311MN Valley
10311 Pathfinder	MN01-311000-Str & Impr-Pathfinder	10311Pathfinder
10311 Red Wing	MN01-311000-Str & Impr-Red Wing	10311Red Wing
10311 Red Wing	MN01-311000-Str & Impr-Red Wing Ash	10311Red Wing
10311 Red Wing	MN01-311000-Str & Impr-Red Wing RDF	10311Red Wing
10311 Riverside - Steam	MN01-311000-Str & Impr-Riverside	10311Riverside - Steam
10311 Riverside - Steam	MN01-311000-Str & Impr-Riverside #7	10311Riverside - Steam
10311 Sherco 1&2	MN01-311000-Str & Impr-Sherco 1	10311Sherco 1&2
10311 Sherco 1&2	MN01-311000-Str & Impr-Sherco 1&2	10311Sherco 1&2
10311 Sherco 1&2	MN01-311000-Str & Impr-Sherco 1&2 C	10311Sherco 1&2
10311 Sherco 1&2	MN01-311000-Str & Impr-Sherco 2	10311Sherco 1&2
10311 Sherco 3	MN01-311000-Str & Impr-Sherco 3	10311Sherco 3
10311 Wilmarth	MN01-311000-Str & Impr-Wilmarth	10311Wilmarth
10311 Wilmarth	MN01-311000-Str & Impr-Wilmarth Ash	10311Wilmarth
10311 Wilmarth	MN01-311000-Str & Impr-Wilmarth RDF	10311Wilmarth
10312 Black Dog	MN01-312000-Blr Plt Eq-Black Dog	10312Black Dog
10312 Black Dog	MN01-312000-Blr Plt Eq-Black Dog #2	10312Black Dog
10312 High Bridge - Steam	MN01-312000-Blr Plt Eq-High Br #4	10312High Bridge - Steam
10312 High Bridge - Steam	MN01-312000-Blr Plt Eq-High Bridge	10312High Bridge - Steam
10312 Allen S. King	MN01-312000-Blr Plt Eq-King	10312Allen S. King
10312 MN Valley	MN01-312000-Blr Plt Eq-MN Valley	10312MN Valley
10312 Pathfinder	MN01-312000-Blr Plt Eq-Pathfinder	10312Pathfinder
10312 Red Wing	MN01-312000-Blr Plt Eq-Red Wing	10312Red Wing
10312 Riverside - Steam	MN01-312000-Blr Plt Eq-Riversd Demo	10312Riverside - Steam
10312 Riverside - Steam	MN01-312000-Blr Plt Eq-Riverside	10312Riverside - Steam
10312 Riverside - Steam	MN01-312000-Blr Plt Eq-Riverside #7	10312Riverside - Steam
10312 Sherco 1	MN01-312000-Blr Plt Eq-Sherco 1	10312Sherco 1
10312 Sherco 1	MN01-312000-Blr Plt Eq-Sherco 1&2	10312Sherco 1
10312 Sherco 1	MN01-312000-Blr Plt Eq-Sherco 1&2 C	10312Sherco 1
10312 Sherco 2	MN01-312000-Blr Plt Eq-Sherco 2	10312Sherco 2
10312 Sherco 3	MN01-312000-Blr Plt Eq-Sherco 3	10312Sherco 3
10312 Wilmarth	MN01-312000-Blr Plt Eq-Wilmarth	10312Wilmarth
	MN01-312200-Coal Cars	
10314 Black Dog	MN01-314000-Turbo Gen-Black Dog	10314Black Dog
10314 Black Dog	MN01-314000-Turbo Gen-Black Dog #2	10314Black Dog
10314 High Bridge - Steam	MN01-314000-Turbo Gen-High Br #4	10314High Bridge - Steam
10314 High Bridge - Steam	MN01-314000-Turbo Gen-High Bridge	10314High Bridge - Steam
10314 Allen S. King	MN01-314000-Turbo Gen-King	10314Allen S. King
10314 MN Valley	MN01-314000-Turbo Gen-MN Valley	10314MN Valley
10314 Pathfinder	MN01-314000-Turbo Gen-Pathfinder	10314Pathfinder
10314 Red Wing	MN01-314000-Turbo Gen-Red Wing	10314Red Wing
10314 Riverside - Steam	MN01-314000-Turbo Gen-Riverside	10314Riverside - Steam
10314 Riverside - Steam	MN01-314000-Turbo Gen-Riverside #7	10314Riverside - Steam
10314 Sherco 1	MN01-314000-Turbo Gen-Sherco 1	10314Sherco 1
10314 Sherco 1	MN01-314000-Turbo Gen-Sherco 1&2	10314Sherco 1
10314 Sherco 1	MN01-314000-Turbo Gen-Sherco 1&2 C	10314Sherco 1
10314 Sherco 2	MN01-314000-Turbo Gen-Sherco 2	10314Sherco 2
10314 Sherco 3	MN01-314000-Turbo Gen-Sherco 3	10314Sherco 3
10314 Wilmarth	MN01-314000-Turbo Gen-Wilmarth	10314Wilmarth
10315 Black Dog	MN01-315000-Acc El Eq-Black Dog	10315Black Dog
10315 Black Dog	MN01-315000-Acc El Eq-Black Dog #2	10315Black Dog
10315 High Bridge - Steam	MN01-315000-Acc El Eq-High Br #4	10315High Bridge - Steam
10315 High Bridge - Steam	MN01-315000-Acc El Eq-High Bridge	10315High Bridge - Steam
10315 Allen S. King	MN01-315000-Acc El Eq-King	10315Allen S. King
10315 MN Valley	MN01-315000-Acc El Eq-MN Valley	10315MN Valley
10315 Pathfinder	MN01-315000-Acc El Eq-Pathfinder	10315Pathfinder
10315 Red Wing	MN01-315000-Acc El Eq-Red Wing	10315Red Wing
10315 Riverside - Steam	MN01-315000-Acc El Eq-Riverside	10315Riverside - Steam
10315 Riverside - Steam	MN01-315000-Acc El Eq-Riverside #7	10315Riverside - Steam
10315 Sherco 1	MN01-315000-Acc El Eq-Sherco 1	10315Sherco 1
10315 Sherco 1	MN01-315000-Acc El Eq-Sherco 1&2	10315Sherco 1
10315 Sherco 1	MN01-315000-Acc El Eq-Sherco 1&2 C	10315Sherco 1
10315 Sherco 2	MN01-315000-Acc El Eq-Sherco 2	10315Sherco 2

10315	Sherco 3	MN01-315000-Acc El Eq-Sherco 3	10315Sherco 3
10315	Wilmarth	MN01-315000-Acc El Eq-Wilmarth	10315Wilmarth
10316	Black Dog	MN01-316000-Pwr Pl Eq-Black Dog	10316Black Dog
10316	Black Dog	MN01-316000-Pwr Pl Eq-Black Dog #2	10316Black Dog
10316	High Bridge - Steam	MN01-316000-Pwr Pl Eq-High Br #4	10316High Bridge - Steam
10316	High Bridge - Steam	MN01-316000-Pwr Pl Eq-High Bridge	10316High Bridge - Steam
10316	Allen S. King	MN01-316000-Pwr Pl Eq-King	10316Allen S. King
10316	MN Valley	MN01-316000-Pwr Pl Eq-MN Valley	10316MN Valley
10316	Pathfinder	MN01-316000-Pwr Pl Eq-Pathfinder	10316Pathfinder
10316	Red Wing	MN01-316000-Pwr Pl Eq-Red Wing	10316Red Wing
10316	Riverside - Steam	MN01-316000-Pwr Pl Eq-Riverside	10316Riverside - Steam
10316	Riverside - Steam	MN01-316000-Pwr Pl Eq-Riverside #7	10316Riverside - Steam
10316	Sherco 1	MN01-316000-Pwr Pl Eq-Sherco 1	10316Sherco 1
10316	Sherco 1	MN01-316000-Pwr Pl Eq-Sherco 1&2	10316Sherco 1
10316	Sherco 1	MN01-316000-Pwr Pl Eq-Sherco 1&2 C	10316Sherco 1
10316	Sherco 2	MN01-316000-Pwr Pl Eq-Sherco 2	10316Sherco 2
10316	Sherco 3	MN01-316000-Pwr Pl Eq-Sherco 3	10316Sherco 3
10316	Wilmarth	MN01-316000-Pwr Pl Eq-Wilmarth	10316Wilmarth
Sherco 1/2 ND Acceleration	Sherco 1/2 ND Acceleration	MN01-Sherco 1&2 Depr Acceleration	Sherco 1/2 ND AccelerationSherco 1/2 ND Acceleration
10340	Border WF	MN01-340045-Wind Rights-Border Wind	10340Border WF
10340045	Courtenay WF	MN01-340045-Wind Rights-Crtny Wind	10340045Courtenay WF
10340045	Foxtail WF	MN01-340045-Wind Rights-Foxtail WF	10340045Foxtail WF
10340045	Grand Meadow	MN01-340045-Wind Rights-Gr Meadow	10340045Grand Meadow
10340045	Lake Benton WF	MN01-340045-Wind Rights-Lk Benton W	10340045Lake Benton WF
10340045	Nobles	MN01-340045-Wind Rights-Nobles	10340045Nobles
10340045	Pleasant Valley WF	MN01-340045-Wind Rights-Pleasant V	10340045Pleasant Valley WF
10341	Border WF	MN01-341045-Str & Impr-Border Wind	10341Border WF
10341	Courtenay WF	MN01-341045-Str & Impr-Crtny Wind	10341Courtenay WF
10341	Foxtail WF	MN01-341045-Str & Impr-Foxtail WF	10341Foxtail WF
10341	Grand Meadow	MN01-341045-Str & Impr-Gr Meadow WF	10341Grand Meadow
10341	Lake Benton WF	MN01-341045-Str & Impr-Lk Benton WF	10341Lake Benton WF
10341	Nobles	MN01-341045-Str & Impr-Nobles	10341Nobles
10341	Pleasant Valley WF	MN01-341045-Str & Impr-Pleasant V	10341Pleasant Valley WF
10342	Border WF	MN01-342045-Fuel Holdr-Border Wind	10342Border WF
10342	Courtenay WF	MN01-342045-Fuel Holdr-Crtny Wind	10342Courtenay WF
10342	Foxtail WF	MN01-342045-Fuel Holdr-Foxtail WF	10342Foxtail WF
10342	Grand Meadow	MN01-342045-Fuel Holdr-Gr Meadow WF	10342Grand Meadow
10342	Lake Benton WF	MN01-342045-Fuel Holdr-Lk Benton WF	10342Lake Benton WF
10342	Nobles	MN01-342045-Fuel Holdr-Nobles WF	10342Nobles
10342	Pleasant Valley WF	MN01-342045-Fuel Holdr-Pleasant V	10342Pleasant Valley WF
10344	Border WF	MN01-344045-Generators-Border Wind	10344Border WF
10344	Courtenay WF	MN01-344045-Generators-Crtny Wind	10344Courtenay WF
10344	Foxtail WF	MN01-344045-Generators-Foxtail WF	10344Foxtail WF
10344	Grand Meadow	MN01-344045-Generators-Gr Meadow WF	10344Grand Meadow
10344	Heron Lake WF	MN01-344045-Generators-Heron Lak WF	10344Heron Lake WF
10344	Lake Benton WF	MN01-344045-Generators-Lk Benton WF	10344Lake Benton WF
10344	Merricourt WF	MN01-344045-Generators-Merricour WF	10344Merricourt WF
10344	Nobles	MN01-344045-Generators-Nobles WF	10344Nobles
10344	Pleasant Valley WF	MN01-344045-Generators-Pleasant V	10344Pleasant Valley WF
10344	Stoneray WF	MN01-344045-Generators-Stoneray WF	10344Stoneray WF
10345	Border WF	MN01-345045-Accessy Eq-Border Wind	10345Border WF
10345	Courtenay WF	MN01-345045-Accessy Eq-Crtny Wind	10345Courtenay WF
10345	Foxtail WF	MN01-345045-Accessy Eq-Foxtail WF	10345Foxtail WF
10345	Grand Meadow	MN01-345045-Accessy Eq-Gr Meadow WF	10345Grand Meadow
10345	Heron Lake WF	MN01-345045-Accessy Eq-Heron Lak WF	10345Heron Lake WF
10345	Lake Benton WF	MN01-345045-Accessy Eq-Lk Benton WF	10345Lake Benton WF
10345	Merricourt WF	MN01-345045-Accessy Eq-Merricour WF	10345Merricourt WF
10345	Nobles	MN01-345045-Accessy Eq-Nobles WF	10345Nobles
10345	Pleasant Valley WF	MN01-345045-Accessy Eq-Pleasant V	10345Pleasant Valley WF
10345	Stoneray WF	MN01-345045-Accessy Eq-Stoneray WF	10345Stoneray WF
10346	Border WF	MN01-346045-Pwr Plt Eq-Border Wind	10346Border WF
10346	Courtenay WF	MN01-346045-Pwr Plt Eq-Crtny Wind	10346Courtenay WF
10346	Foxtail WF	MN01-346045-Pwr Plt Eq-Foxtail WF	10346Foxtail WF
10346	Grand Meadow	MN01-346045-Pwr Plt Eq-Gr Meadow WF	10346Grand Meadow
10346	Heron Lake WF	MN01-346045-Pwr Plt Eq-Heron Lak WF	10346Heron Lake WF
10346	Lake Benton WF	MN01-346045-Pwr Plt Eq-Lk Benton WF	10346Lake Benton WF
10346	Merricourt WF	MN01-346045-Pwr Plt Eq-Merricour WF	10346Merricourt WF
10346	Nobles	MN01-346045-Pwr Plt Eq-Nobles WF	10346Nobles
10346	Pleasant Valley WF	MN01-346045-Pwr Plt Eq-Pleasant V	10346Pleasant Valley WF
10346	Stoneray WF	MN01-346045-Pwr Plt Eq-Stoneray WF	10346Stoneray WF
10348010	Fuel Storage	MN01-348010-Other Prod Fuel HldWind	10348010Fuel Storage
10344	Mower WF	ZMN01-34445-Generators-Mower WF	10344Mower WF
10340	Blazing Star I WF	MN01-340045-Wind Rights-Blaz Star 1	10340Blazing Star I WF

10341 Blazing Star I WF	MN01-341045-Str & Impr-Blaz Star 1	10341Blazing Star I WF
10342 Blazing Star I WF	MN01-342045-Fuel Holdr-Blaz Star 1	10342Blazing Star I WF
10344 Blazing Star I WF	MN01-344045-Generators-Blaz Star 1	10344Blazing Star I WF
10345 Blazing Star I WF	MN01-345045-Accessy Eq-Blaz Star 1	10345Blazing Star I WF
10346 Blazing Star I WF	MN01-346045-Pwr Plt Eq-Blaz Star 1	10346Blazing Star I WF

N/A

Plant	Location	Proposed net salvage percent
Blazing Star I	Minnesota	-11.3%
Border Winds	North Dakota	-9.5%
Courtenay Wind	North Dakota	-10.3%
Foxtail Wind	North Dakota	-9.4%
Grand Meadow Wind	Minnesota	-12.4%
Lake Benton II Wind	Minnesota	-10.5%
Nobles Wind	Minnesota	-8.5%
Pleasant Valley	Minnesota	-11.7%

Average (Rounded to Tenths Decimal)	-10.4%

NORTHERN STATES POWER COMPANY

A MINNESOTA CORPORATION

TRANSMISSION, DISTRIBUTION AND GENERAL

ELECTRIC, GAS AND COMMON

DEPRECIATION RATE STUDY

July 2017

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

NORTHERN STATES POWER COMPANY
A MINNESOTA CORPORATION
TRANSMISSION, DISTRIBUTION AND GENERAL
ELECTRIC, GAS AND COMMON
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Northern States Power Company, a Minnesota corporation ("NSP" or "Company"), engaged Alliance Consulting Group to conduct a depreciation study of the Company's Electric, Gas, and Common transmission, distribution, and general utility plant depreciable assets as of January 1, 2017. This analysis recommends a number of changes in the lives of various types of assets, by account number under the FERC Uniform System of Accounts. The changes in lives discussed in this Executive Summary are discussed in more detail in the study.

For Electric Transmission, Distribution and General Plant depreciable accounts, the lives for many of the accounts increased. There are 18 accounts, nine that have increasing lives, three that have decreasing lives, and the lives of the other six accounts were unchanged. The account with the greatest change in life is account 354 Transmission Towers and Fixtures which moved 5 years longer in life. There is also a trend toward higher negative net salvage with 12 accounts increasing (i.e. more negative) their negative net salvage and the remaining six accounts remaining unchanged. The account with the largest increase in negative net salvage is Account 364 Distribution Poles, where the net salvage moved from negative 100 percent to a negative 120 percent, which equates to a change of 20 percent.

For Electric Amortized Plant, there are 20 accounts including one intangible account, 15 general plant accounts, and four distribution accounts. Most amortization periods are remaining the same, with amortization lives increasing for Account 391 Network Equipment, Account 397 General Communication Equipment, and Account 397 General Two Way and decreasing lives for Accounts 392

Transportation Equipment for Light Trucks, Trailers, and Heavy Trucks. Net salvage increased (became more negative) for three accounts: Account 368 Distribution Line Capacitors, Account 370.1 Distribution Meters-Old and Account 370 Distribution Meters. Net salvage became positive in Accounts 392 (all subaccounts) and 396. The largest change was in Account 392 General Trailers changing from zero percent to positive 20 percent for net salvage.

For Gas Transmission, Distribution and General Plant depreciable accounts, there are 11 accounts including six that have increasing lives and five accounts that were unchanged. The accounts with the greatest change in life were Account 366 Transmission Structures and Improvements and Account 376 Distribution Mains-Metallic which moved 13 and 12 years longer in life respectively. There are changes in net salvage with four accounts increasing (i.e. more negative) their negative net salvage, two accounts decreasing (i.e. less negative) their negative net salvage, and the remaining five accounts remaining unchanged. The accounts with the greatest change in net salvage were Account 375 Distribution Structures and Improvements, Account 376 Distribution Mains-Metallic, and Account 376 Distribution Mains-Plastic that all increased by five percent.

For Gas Amortized Plant, there are 19 accounts including two intangible accounts, 14 general plant accounts, and three distribution accounts. Most amortization periods remain the same, and amortization periods increase for Account 391 General Network Equipment, Account 397 General Communication Equipment, and Account 397 General Two Way and decreasing lives for Accounts 392 Transportation Equipment for Light Trucks, Trailers, and Heavy Trucks. Net salvage increased (more negative) for two accounts: Account 381 Distribution Meters and Account 383 Distribution House Regulators. Net salvage became positive in Accounts 392 (all subaccounts) and 396. The largest change was in Account 392 General Trailers changing from zero percent to positive 20 percent for net salvage.

For Common Plant, there are 20 accounts including two depreciable accounts and 18 amortized accounts of which there are five intangible accounts and 13 general plant accounts. The life for Account 390 Structures and Improvements became shorter, and many amortization periods remain the same. Amortization periods increased for Account 391 General Network Equipment, Account 397 General Communication Equipment, and Account 397 General Two Way and decreased for Accounts 392 Transportation Equipment for Light Trucks, Trailers, and Heavy Trucks. Net salvage became positive in Accounts 392 (all subaccounts) and Account 396 Power Operated Equipment. The largest change was in Account 392 Transportation Equipment for Trailers changing from zero percent to positive 20 percent for net salvage. Amortization rates were updated to reflect any imbalance between book and theoretical reserves.

For life and net salvage analysis, the study used total Company results. After selecting life and net salvage parameters, those depreciation parameters were applied to the total Company plant using the Minnesota approved depreciation rates to provide the reserve balances for transmission and general plant. Plant balances for Minnesota state-specific assets and their reserve balances using the Minnesota approved depreciation rates were used for Electric and Gas Distribution plant.

All annual accrual rates were determined using the straight line, broad group, remaining life depreciation system. Depreciation and amortization rates reflect any imbalance between actual and theoretical reserves. Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of each depreciable group.

Given the many changes in life and net salvage in this study, this study recommends a reallocation of book reserve by plant account within each function. This reallocation does not change the total reserve within each function. Rather, reallocating the reserve within a function realigns the depreciation reserve balances within each function using the proposed life and net salvage parameters.

This study recommends an overall decrease of approximately $7.4 million in annual depreciation expense compared to the depreciation rates currently in effect after implementing the Minnesota Public Utilities Commission order in Docket No.

E,G002/D-12-858. This consists of an increase of $3.7 million in annual depreciation expense for Electric facilities, a decrease of $7.1 million in annual depreciation expense for Gas facilities compared to the depreciation rates currently in effect, and a decrease of approximately $4.0 million for Common plant in annual depreciation expense. The overall decrease in depreciation expense is driven by changes in life and net salvage as well as treatment of any book and theoretical reserve imbalance. Appendix B demonstrates the change in depreciation expense for the various accounts. If approved by the Commission, the changes recommended in the study would be used by the Company effective January 1, 2018.

NORTHERN STATES POWER COMPANY

A MINNESOTA CORPORATION

TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT

ELECTRIC, GAS AND COMMON

DEPRECIATION RATE STUDY

July 2017

Table of Contents

PURPOSE

The purpose of this study is to develop depreciation rates for the period beginning January 1, 2018 for the depreciable property as recorded on the books of Northern States Power Company, a Minnesota corporation ("NSP" or "Company"), at January 1, 2017. The account based depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of NSP's property on a straight-line basis. Non-depreciable property and production plant were excluded from this study.

STUDY RESULTS

Overall depreciation rates for all NSP depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $303.7 million based on NSP depreciable investment at January 1, 2017. The annual equivalent depreciation expense calculated by the same method using the approved rates was $310.6 million. These proposed rates translate into an annual depreciation accrual for Electric of $220.5 million, Gas of $27.4 million, and Common of $55.8 million. Appendix A demonstrates the development of the annual depreciation rates and accruals by account. Appendix B presents a comparison of approved rates versus proposed rates by account. Appendix C presents a summary of mortality and net salvage estimates by account. Appendix D presents a comparison between theoretical and book accumulated depreciation reserves for each account. Appendix E presents the net salvage analysis for all accounts. The overall decrease in depreciation expense is driven by changes in life and net salvage as well as treatment of any book and theoretical reserve imbalance. Shown below is a summary of the results for each group and function:

Type of Plant (in millions)	Accrual at Existing Rates	Accrual at Proposed Rates	Difference
Electric Transmission Depreciable	$67.9	$72.4	$4.5
Electric Distribution Depreciable	$77.9	$80.2	$2.3
Electric General Depreciable	$1.4	$1.5	$0.1
Electric Distribution Amortized	$16.5	$16.4	($0.1)
Electric General & Intangible Amortized	$53.1	$50.0	($3.1)
Gas Transmission	$1.6	$1.2	($0.4)
Gas Distribution Depreciated	$23.3	$19.1	($4.2)
Gas Distribution Amortized	$4.8	$4.0	($0.8)
Gas General Depreciated	$0.03	$0.04	($0.0)
Gas General & Intangible Amortized	$4.3	$3.1	($1.2)
Common Depreciated	$5.2	$5.8	$0.6
Common Amortized	$54.6	$50.0	($4.6)
Total	$310.6	$303.7	($6.9)

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value (which may be negative), is charged to the depreciation reserve.

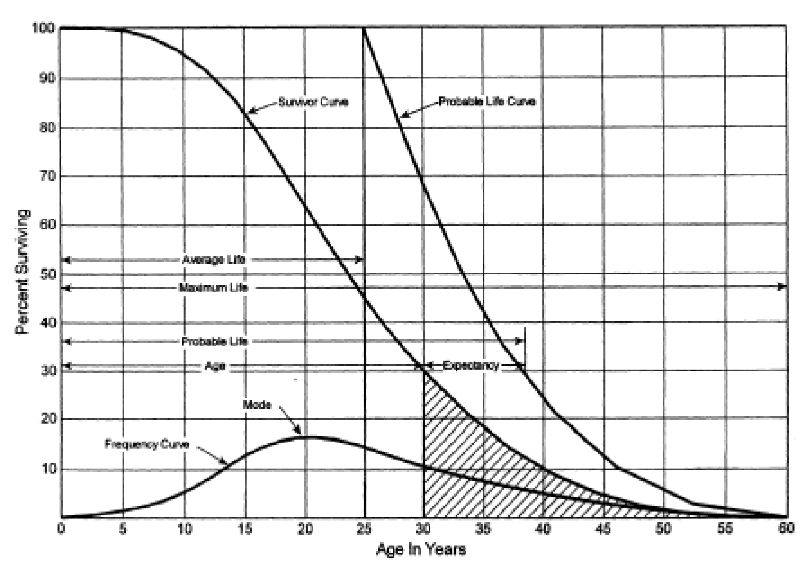
Basis of Depreciation Estimates

The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A.

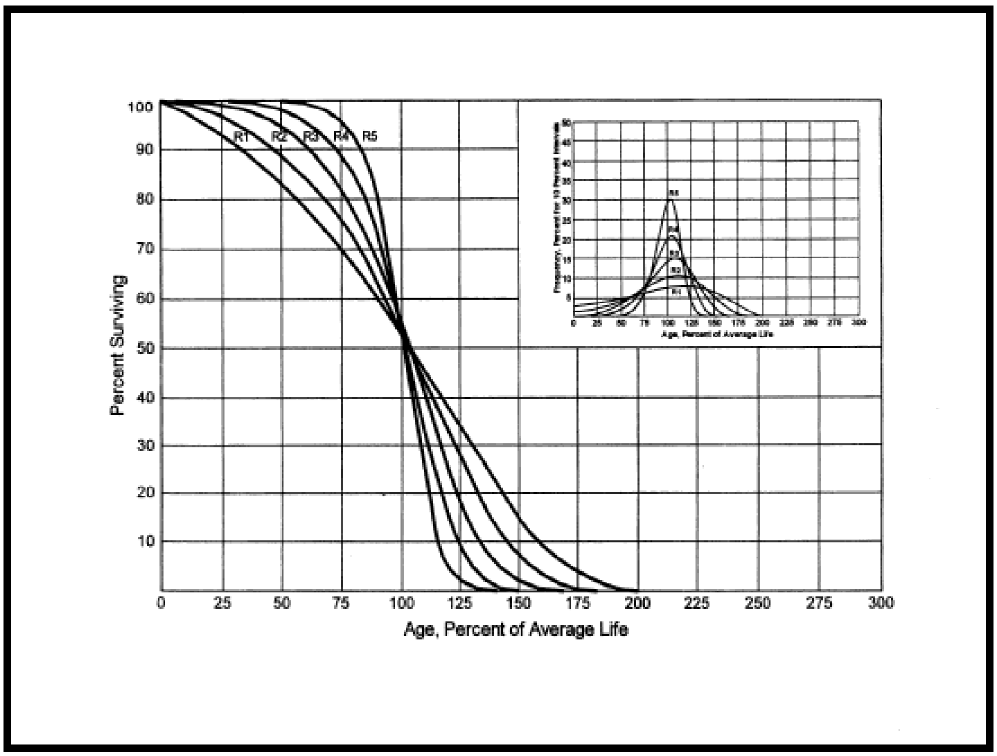
Actuarial analysis was used with each account within a function where sufficient data was available, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group (for example, wood distribution poles) do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Survivor Curves ("Iowa Curves") are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the curve family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. A SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Simulated Plant Record Procedure

The Simulated Plant Record Procedure - Balances approach ("SPR") is one of the commonly accepted approaches to analyze mortality characteristics of utility property. SPR was applied to some of the Electric and Gas Distribution accounts due to the unavailability of vintaged transactional data. In this method, an Iowa Curve and average service life are selected as a starting point of the analysis and its survivor factors are applied to the actual annual additions to give a sequence of annual balance totals. These simulated balances are compared with the actual balances by using both graphical and statistical analysis. Through multiple comparisons, the mortality characteristics (as defined by an average life and Iowa Curve) that are the best match to the property in the account can be found.

The Conformance Index ("CI") is one measure used to evaluate various SPR analyses. CIs are also used to evaluate the "goodness of fit" between the actual data and the Iowa Curve being referenced. The sum of squares difference ("SSD") is a summation of the difference between the calculated balances and the actual balances for the band or test year being analyzed. This difference is squared and then summed to arrive at the SSD, where n is the number of years in the test band as follows:

$$SSD = \sum_{1}^{n} (Calculated\ Balance_i - Observed\ Balance_i\ )^2$$

This calculation can then be used to develop other calculations, which the analyst feels might give a better indication for the "goodness of fit" for the representative curve under consideration. The residual measure ("RM") is the square root of the average squared differences as developed above. The residual measure is calculated as follows:

$$RM = \sqrt{(\frac{SSD}{n})}$$

The CI is developed from the residual measure and the average observed plant balances for the band or test year being analyzed. The calculation of conformance index is shown below:

$$CI = \frac{\sum_1^n Balances_i / n}{RM}$$

The Retirement Experience Index ("REI") gives an indication of the maturity of the account and is the percent of the property retired from the oldest vintage in the band at the end of the test year. Retirement indices range from 0 percent to 100 percent and a REI of 100 percent indicates that a complete curve was used. A REI less than 100 percent indicates that the survivor curve was truncated at that point. The originator of the SPR method, Alex Bauhan, suggests ranges of value for the CI and REI. The relationship for CI proposed by Bauhan is shown below[1]:

CI	Value
Over 75	Excellent
50 to 75	Good
25 to 50	Fair
Under 25	Poor

1 Public Utility Depreciation Practices, p. 96.

The relationship for REI proposed by Bauhan[2] is shown below:

REI	Value
Over 75	Excellent
50 to 75	Good
33 to 50	Fair
17 to 33	Poor
17 and below	Valueless

Depreciation analysts have used these measures in analyzing SPR results for nearly 60 years, since the SPR method was developed. Both the CI and REI statistics provide the analyst with important information with which to make a comparison between a band of simulated or calculated balances and the observed or actual balances in the account being studied.

Statistics are useful in analyzing mortality characteristics of accounts, as well as determining a range of service lives to be analyzed using the detailed graphical method. However, these statistics boil all the information down to one, or at most, a few numbers for comparison. Visual matching through comparison between actual and calculated balances expands the analysis by permitting the analyst to view many points of data at a time. The goodness of fit should be visually compared to plots of other Iowa Curve dispersions and average lives for the selection of the appropriate curve and life. Detailed information for each account is shown later in this study and in workpapers.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

2 Public Utility Depreciation Practices, p. 97.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing the bands on which to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the Transmission, Distribution, and General Plant accounts for the Electric, Gas, and Common utilities requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

The Commission has approved NSP's use the average life group ("ALG") depreciation procedure in various proceedings. At the request of the Company, this study continues to use the ALG depreciation procedure to group the assets within each account. After average service life and a dispersion curve were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG is defined by their respective account dispersion curve, life, and salvage estimates. A straight-line rate for each ALG is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense and dividing the annual depreciation expense by the surviving investment. The resultant rate for each ALG group is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net book cost over the life of each account by averaging many components.

Theoretical Depreciation Reserve

The book depreciation reserve was derived from Company records and was reallocated from a functional level to individual accounts. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio ("RR") at any given age is calculated as:

$$RR = 1 - \frac{(\text{Average Remaining Life})}{(\text{Average Service Life})} * (1 - \text{Net Salvage Ratio})$$

The use of the remaining life method effectively spreads any actual to theoretical reserve variance over the expected remaining life of the account.

Change to Average Life Group Remaining life Depreciation System

In the Company's 2013 and 2014 electric rate cases (Docket Nos. E002/GR-12-961 and E002/GR-13-868 respectively) there was significant attention given to the difference in the theoretical and actual reserves. To address that concern, the Company recommended in the 2013 electric rate case that the net book value be recovered over the remaining life of each Electric and Common account. The issue was resolved by spreading the theoretical surplus over periods much shorter than the remaining lives. In the Company's last depreciation study, Docket No. E,G002/D-12-858 (5-year depreciation study), the remaining life depreciation system was proposed to address those concerns but was not adopted because of the treatment afforded to the theoretical surplus in the 2012 and 2013 electric rate cases. This 2017 study again recommends use of the remaining life depreciation system. Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of each depreciable group. Use of remaining life ensures that the difference between book and theoretical reserve will be amortized ratably over the remaining life of the group.

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis and salvage analysis sections and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from Phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[3] documents the steps used in conducting this study. Depreciation Systems, page 289 documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, write logic supporting forecasts and estimation, and write final report.

[3] Introduction to Depreciation for Public Utilities and Other Industries, AGA EEI, 2013.

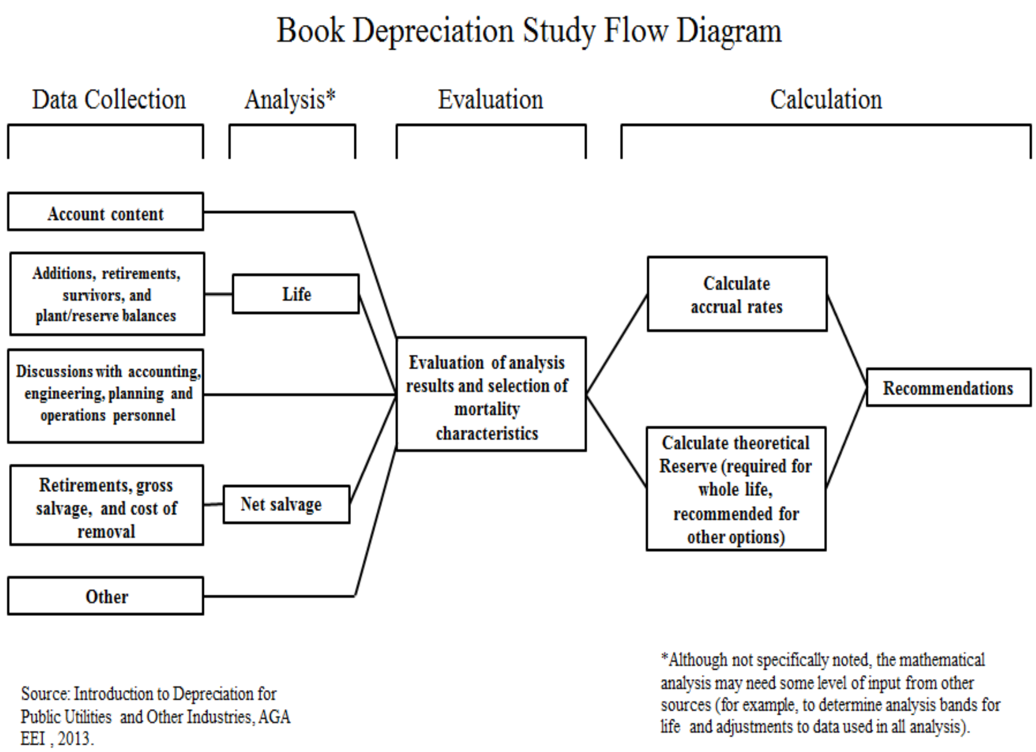


Figure 1

NORTHERN STATES POWER COMPANY - MINNESOTA

DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable accounts of NSP were calculated by the straight-line method, average life group procedure, and remaining-life technique. With this approach, remaining lives were calculated according to standard ALG expectancy techniques, using the Iowa Curves noted in the calculation. For each plant account under the FERC Uniform System of Accounts, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix A.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the Retirement Rate actuarial methods. After establishing the appropriate average service lives and retirement dispersion, the remaining life was computed for each account. The theoretical depreciation reserve with zero net salvage was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the General Discussion section. The difference between book depreciation reserve and theoretical reserve was then spread over the remaining life by ALG. Remaining life computations are found for each account in workpapers.

Calculation Process

Annual depreciation expense amounts for all accounts were calculated by the straight line, remaining life procedure.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$\text{Annual Accrual Rate} = \frac{(100\% - \text{Net Salvage Percent})}{\text{Average Service Life}}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, average life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$\text{Composite Remaining Life} = \frac{\sum \text{Original Cost} - \text{Theoretical Reserve}}{\sum \text{Whole Life Annual Accrual}}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation where the Net Salvage% represents future net salvage.

$$\text{Annual Depreciation Expense} = \frac{\text{Original Cost} - \text{Book Reserve} - (\text{Original Cost}) * (1 - \text{Net Salvage}\,\%)}{\text{Composite Remaining Life}}$$

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$\text{Annual Depreciation Rate} = \frac{\sum \text{Annual Depreciation Expense}}{\sum \text{Original Cost}}$$

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. Book depreciation reserves were allocated from a functional level to individual accounts and the theoretical reserve computation was used to compute a composite remaining life for each account. A comparison between theoretical reserve and the reallocated book reserve is shown in Appendix D for all accounts.

Life Analysis

The retirement rate actuarial analysis method was applied to accounts which had sufficient aged data for Northern States Power Company - Minnesota. Some of the mass distribution accounts only had aged retirement data from transaction year 2001 forward. Those accounts were analyzed with the SPR balances method. The distribution accounts analyzed with SPR were: Electric 364 Poles, Towers & Fixtures, 365 Overhead Conductor & Devices, 366 – Underground Conduit, 367 Underground Conductor and Devices, 369 Services - Overhead, 369 Services - Underground, 373 Street Lighting & Signal Systems, and Gas: 376 Mains - Metallic, 376 Mains - Plastic, 380 Services - Metallic, and 380 Services - Plastic. For each account with sufficient data, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. A selected curve for each account is shown in the Life Analysis Section of this report. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

For each account on the overall band (i.e. placement from earliest vintage year which varied for each account through 2016), approved survivor curves from MPUC Docket No. E,G002/D-12-858, modified by subsequent orders if applicable, were used as a starting point. Then using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e. L, S. or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed: in increments of approximately 20 years, for instance 1967-2016, 1987-2016, etc. Next, placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

For account(s) which had insufficient data for actuarial analysis, a simulated plant record method analysis was performed at intervals for the overall band and at 10 year intervals within the overall balance period. In addition to reviewing the SPR analysis for each band and account, a graphical comparison between actual and simulated balances was performed.

These results are used in conjunction with all other factors that may influence asset lives.

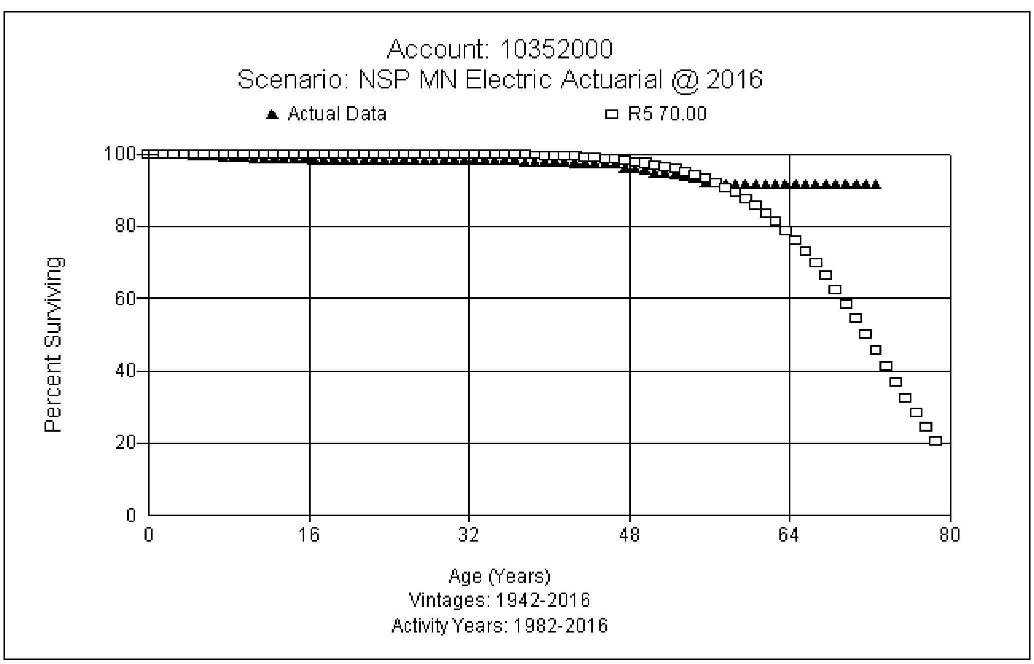
ELECTRIC PLANT

TRANSMISSION

Transmission Accounts, FERC Accounts 352-358

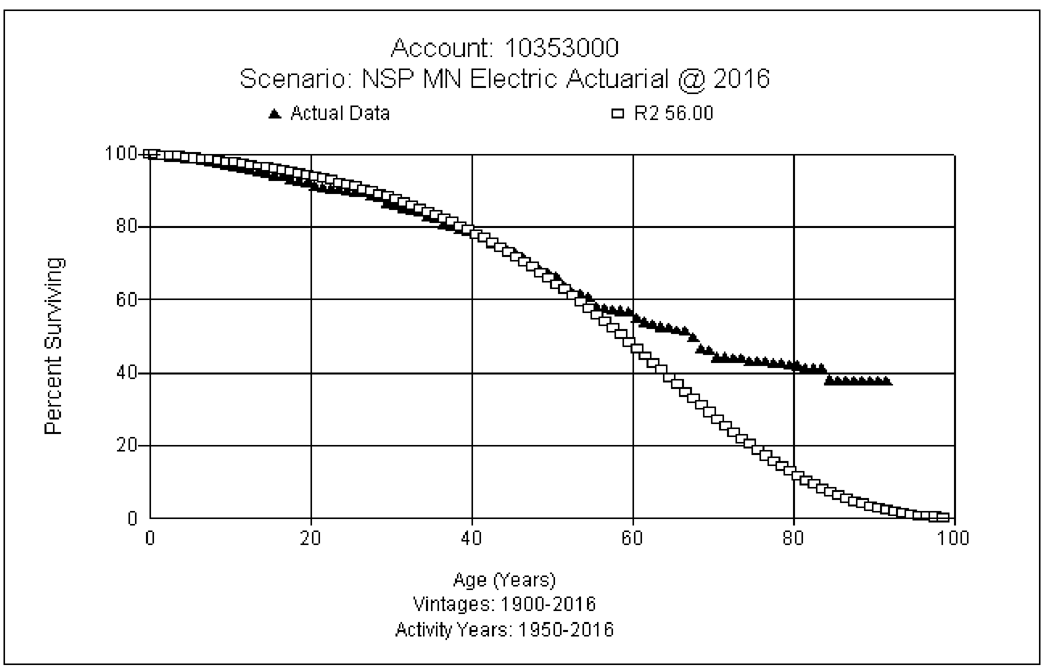
FERC Account 352 Transmission Structures & Improvements (proposed 70 year life with a R5 dispersion curve)

This account includes buildings, fencing and other structures found in a transmission substation. The current investment balance is $103.1 million. The approved life and curve is 68 years with a R5 dispersion curve. There is a limited amount of data for actuarial analysis. Narrow bands do not have sufficient data with curves that stop at 97 percent are higher. For the overall band, a longer life greatly in excess of the current 45 year life is indicated. Company personnel anticipate a longer life than approved, in the range of 65 to 70 years. Frost and severe winter conditions are factors that can contribute to retirements in Minnesota. Based on judgment and Company experience, a 70 year life is proposed for this account while retaining the R5 dispersion curve.



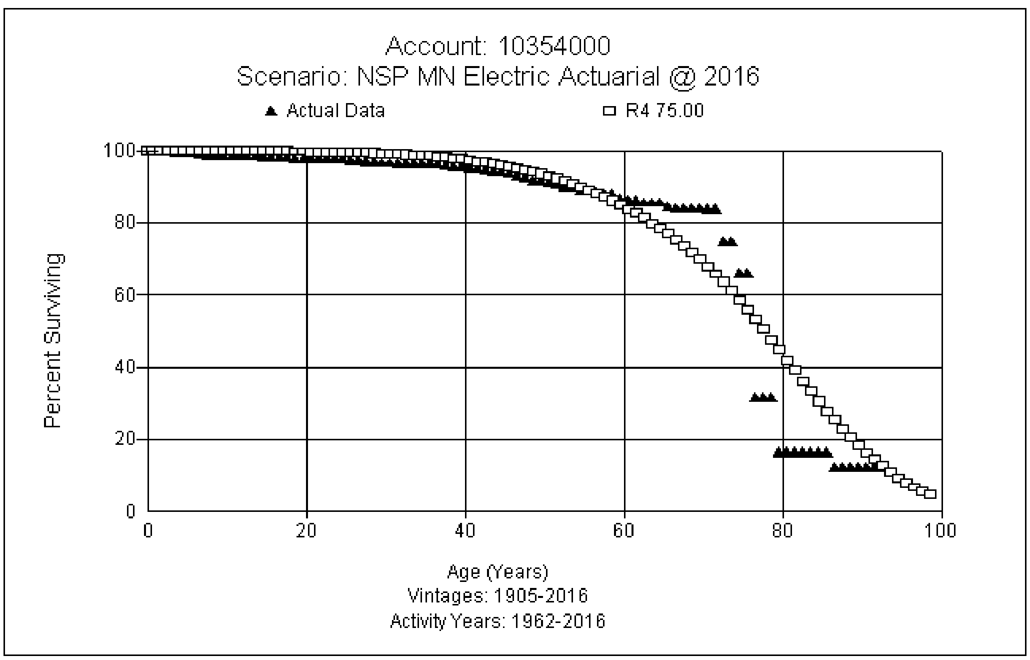
FERC Account 353 Transmission Station Equipment (proposed 56 year life with a R2 dispersion curve)

This account contains a wide variety of transmission substation equipment, from circuit breakers to switchgear. The current investment balance is $1.2 billion. The current approved life is 56 years with a R2 dispersion curve. The Company maintains a table of low, normal, and long expectations for the various assets types in this account. Company personnel believe the middle or normal estimate is the most reflective of the Company assets. Relays are transitioning from electromechanical and solid state to microprocessor relays with an estimated life of 30 years. Company personnel expect to replace all older relays in the next 8-10 years. Life analysis across a variety of bands shows a longer life, in the 50 year and over range. Based on actuarial experience and judgment regarding the asset groups in this account, this study recommends retaining a 56-year life with an R2 dispersion curve for this account.



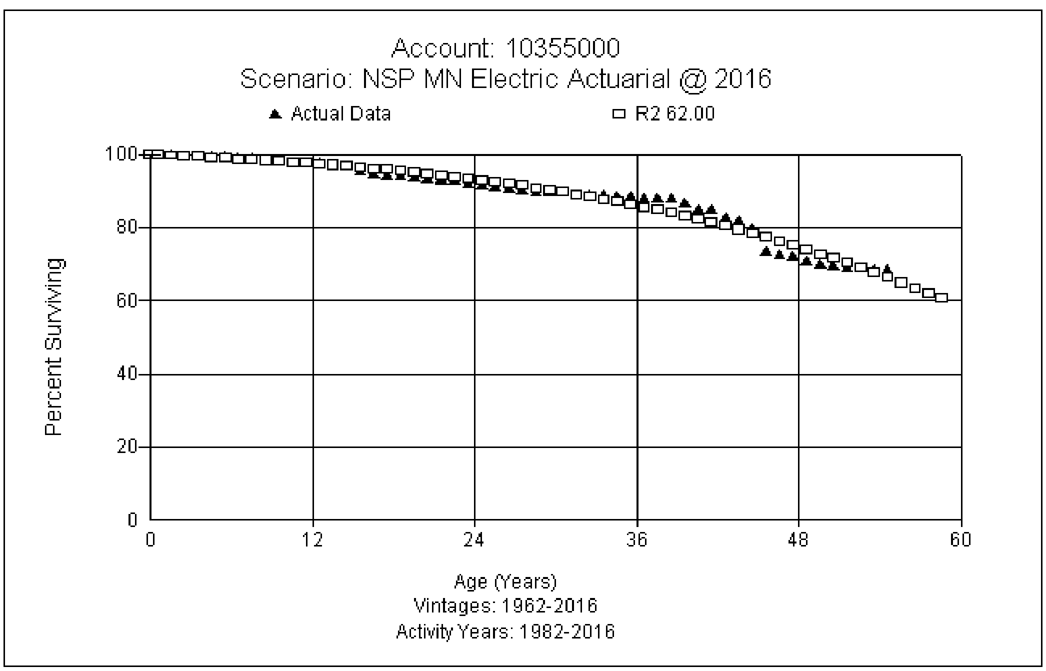
FERC Account 354 Transmission Towers & Fixtures (proposed 75 year life with a R4 dispersion curve)

This account consists of Transmission towers and fixtures, which are used to transmit electricity at a voltage of 69 kV and above. The current investment balance is $118.6 million. The current approved life is the 70 years with a R4 dispersion curve. There has been a smaller amount of retirements occurring for towers versus other transmission accounts. Some towers are beginning to exhibit corrosion. Based on Company experience and judgment, this study recommends moving to a 75 year life with a R4 dispersion curve for this account.



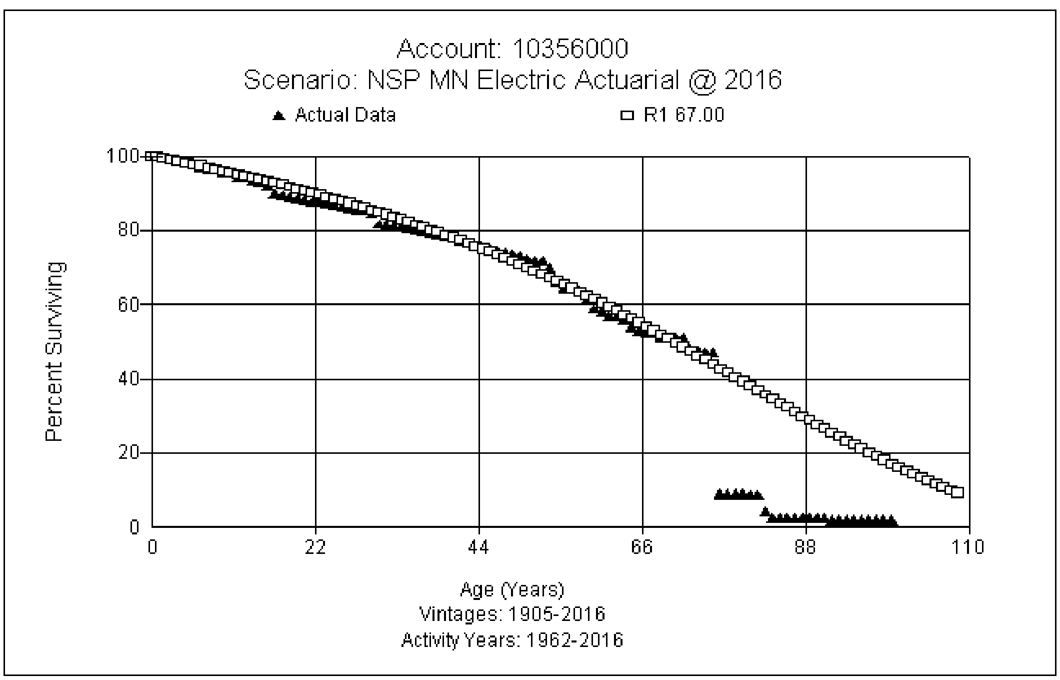
FERC Account 355 Transmission Poles & Fixtures (proposed 62 year life with a R2 dispersion curve)

This account consists of Transmission poles and fixtures, which are used to transmit electricity at a voltage of 69 kV and above. The current investment balance is $1.3 billion. The current approved life is 62 years with a R2 dispersion curve. Company personnel expect that 100 percent of all structures will have been retired by the age of 75 years, and perhaps 80 percent will last past 50 years. A small percentage will retire in the first 25 years. By 75 years, structures will have degraded to the point that they will all have to be replaced. Rot, obsolescence, change in energy flow, and new capacity are all potential causes of retirement. Based on the best fitting curves for the majority of the placement and experience band combinations, retaining a life of 62 years with a R2 dispersion curve is recommended for this account.



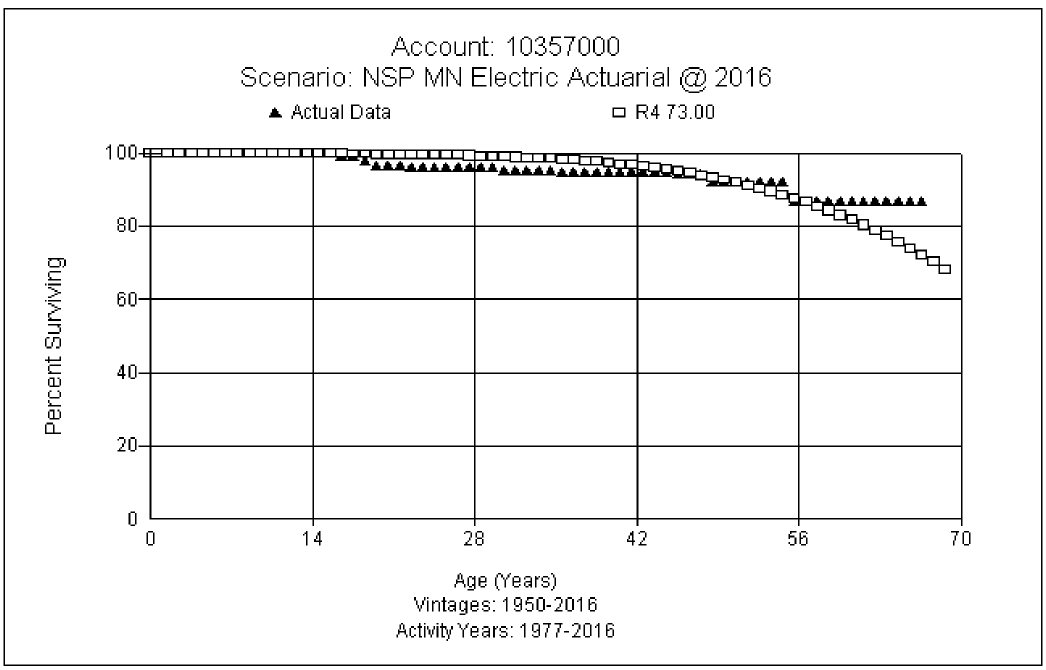
FERC Account 356 Transmission Overhead Conductor & Devices (proposed 67 year life with a R1 dispersion curve)

This account consists of Transmission overhead conductors, which are used to transmit electricity at voltages of 69 kV and above. The current investment balance is $532.7 million. The current approved life is 63 years with a R1 dispersion curve. Company personnel anticipate that conductor will have a life similar to poles in Account 355. Conductor may be replaced when it is too small or exhibits problems such as corrosion, falling splices, storms, or sag issues. Glass insulators are being replaced on dead ends and polymer on tangents. Polymer insulators are expected to last 30 years and be replaced once over the life of the line. Based on the actuarial analysis, life indications are moving to a longer life, as noted by Company personnel. This study recommends a life of 67 years with a R1 dispersion curve for this account.



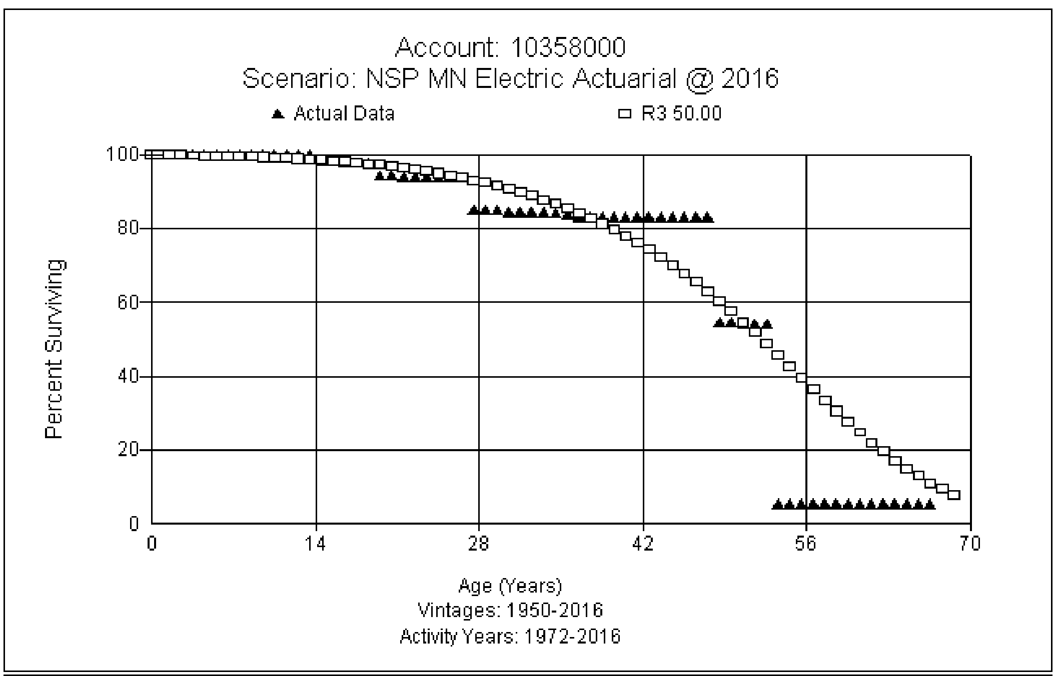
FERC Account 357 Transmission Underground Conduit (proposed 73 year life with a R4 dispersion curve)

This account consists of underground conduit. The current investment balance is $25.9 million. The current approved life is 73 years with a R4 dispersion curve. Retirement data is limited for this account. Company personnel believe the current life for conduit is reasonable and recommend a life around 70 years. Based on actuarial analysis and input from Company personnel, this study recommends retaining a life of 73 years with a R4 dispersion curve for this account.



FERC Account 358 Transmission Underground Conductor & Devices (proposed 50 year with a R3 dispersion curve)

This account consists of underground conductor. The lines are low pressure oil filled; paper wrapped 500 MCM (thousands of circular mills, wire gauge measurement) copper cable. The current investment balance is $30.7 million. The current approved life is 55 years with a R2 dispersion curve. Company personnel indicate overall a life of 50 years for underground conductor is a reasonable expectation. Most conductor is HPFF (high pressure fluid filled) which the manufacturer will not make in the future and will have to be replaced with XPLE (solid dielectric cable) within a few years. Based on input from Company personnel and actuarial analysis, this study recommends moving to a life of 50 years with a R3 dispersion curve for this account

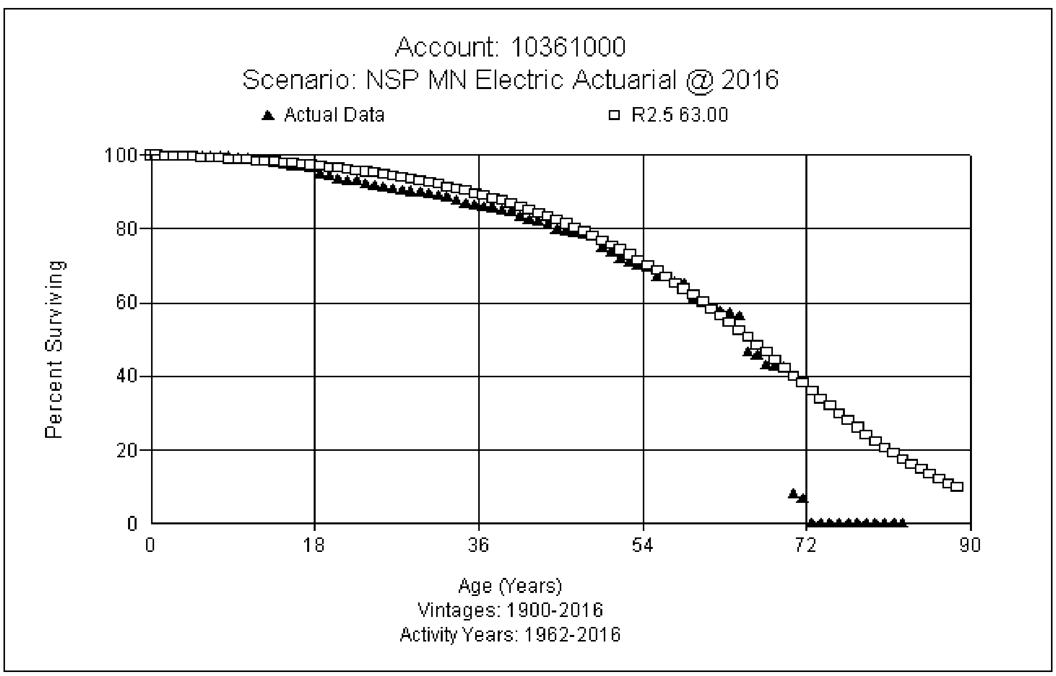


DISTRIBUTION

Distribution Accounts, FERC Accounts 361 - 373

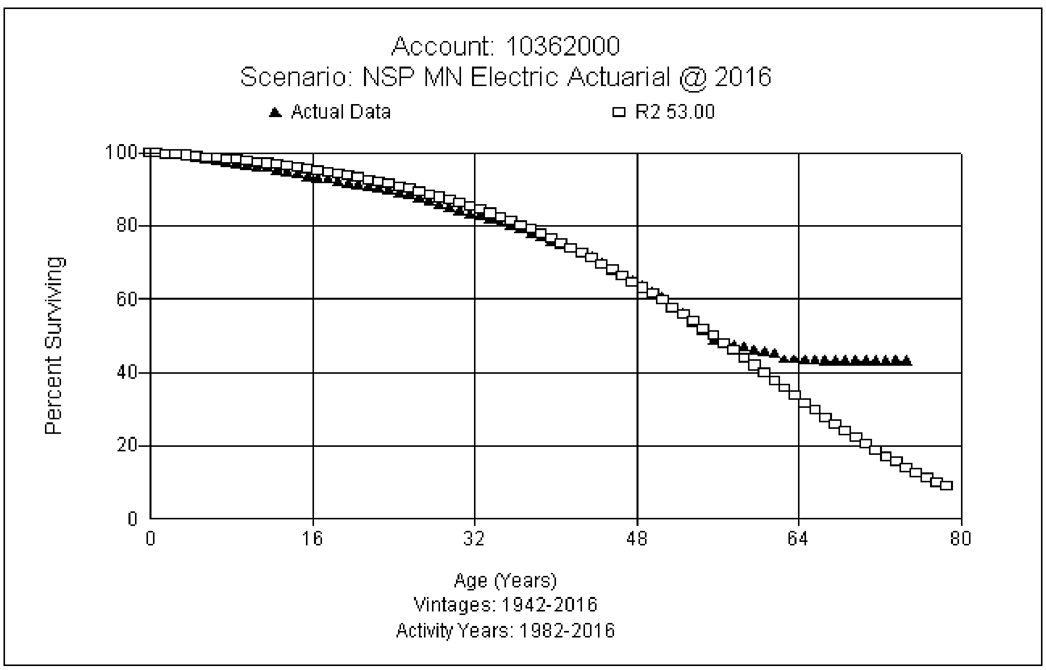
FERC Account 361 Distribution Structures & Improvements (proposed 63 year life with a R2.5 dispersion curve)

This grouping contains facilities ranging from fencing to other structures found in distribution substations. The current investment balance for Minnesota is $43.7 million for this account. The current approved life is a 60 years with a R3 dispersion curve. Life analysis results are based on a total Company data. Company personnel anticipate a longer life than currently approved with the expectation that it will be less than Account 352, Transmission Structures and Improvements. After analyzing actuarial analysis results, a life of 63 years with a R2.5 dispersion curve is recommended for this account.



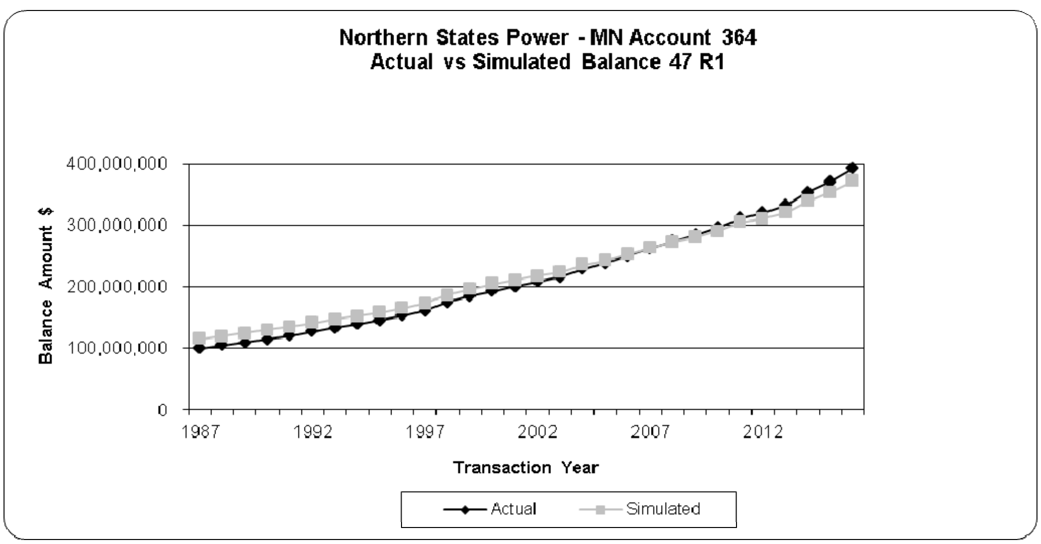
FERC Account 362 Distribution Station Equipment (proposed 53 year life with a R2 dispersion curve)

This grouping contains a wide variety of distribution substation equipment, from circuit breakers to switchgear. The current investment balance for Minnesota is $553.0 million. The current approved life is a 55 years with a R1.5 dispersion curve. Life analysis results are based on total Company data. Company personnel expect the life of this account will be slightly less than Account 353, Transmission Substation Equipment. Multiple placement and experience bands show that a 53 year life with a R2 dispersion curve is a good fit for many bands. Based on Company history and judgment, this study recommends a life of 53 years with a R2 dispersion curve for this account.



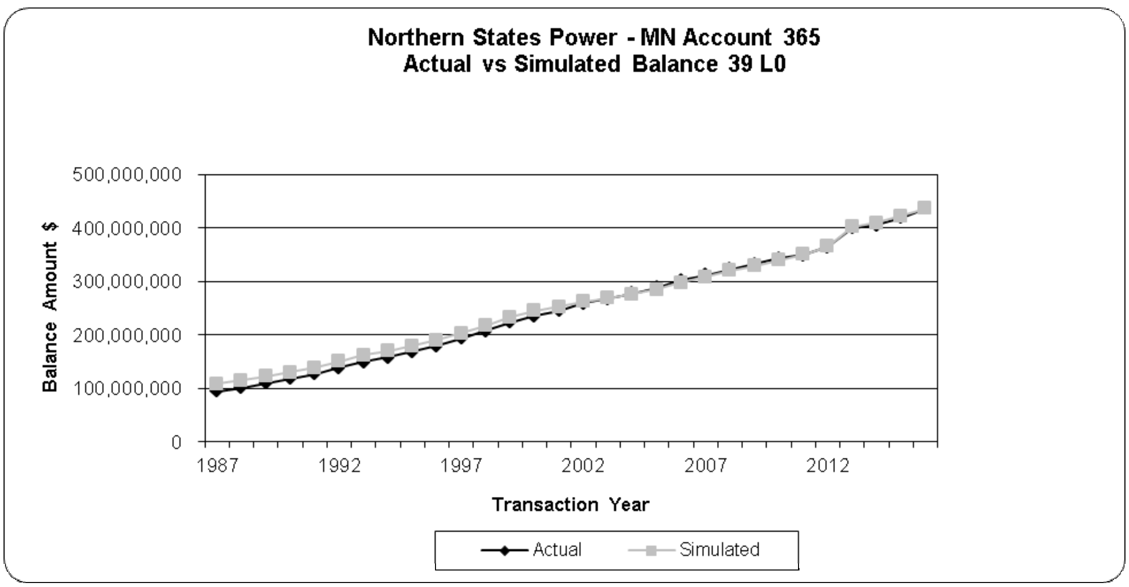
FERC Account 364 Distribution Poles, Towers & Fixtures (proposed 47 year life with a R1 dispersion curve)

This account contains poles and towers of various material types: wood and steel. Most of the poles across the system are made of wood. The height of these assets can range from 35 feet to 70 feet with the prevalent sizes being 45 feet and up. The current investment balance for Minnesota is $343.5 million for this account. The current approved life is 44 years with a R1 dispersion curve. Life analysis results are based on total Company data. SPR analysis was used since actuarial results are available from 2001 forward only. Company personnel report that western red cedar poles were used up to 10 years ago and poles are now treated pine. Company experts believe the life of cedar would probably be 40-45 years and treated pine would be less than 40 years. The two biggest issues are rot and relocations. A pole testing program is producing proactive replacement activity. Fiberglass cross arms are starting to be installed which will have a longer life. Steel is only used when building near a transmission structure. Based on life analysis results and input from Company personnel a 47 year life with a R1 dispersion curve is recommended for this account. A comparison of actual versus simulated balances is shown below.



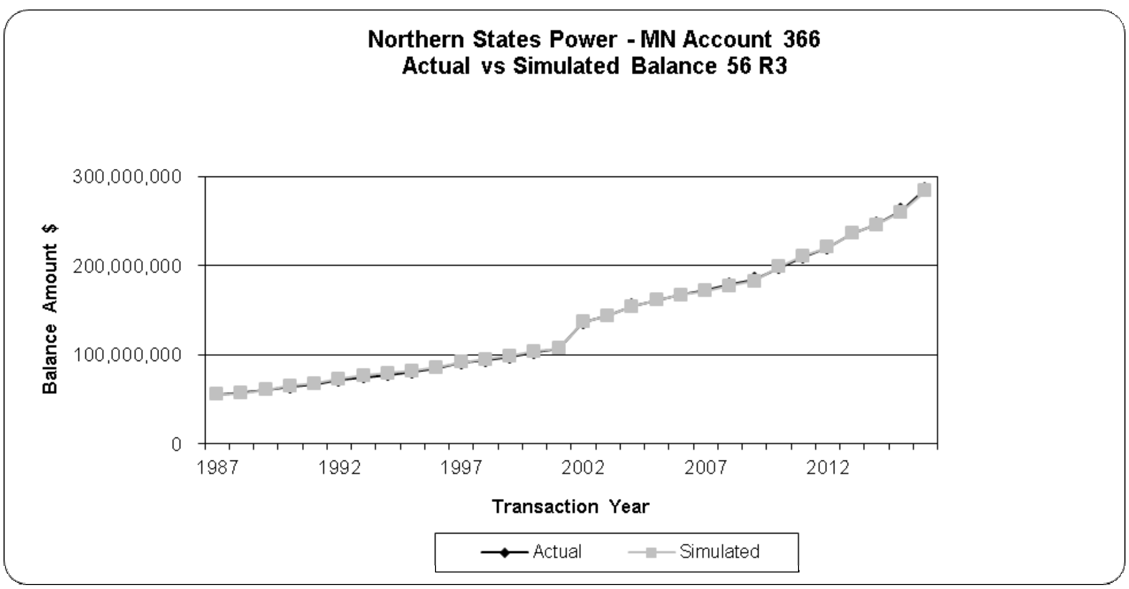
FERC Account 365 Distribution Overhead Conductor & Devices (proposed 39 year life with a L0 dispersion curve)

This account consists of overhead conductor of various thickness, as well as various switches and reclosers. The current investment balance for Minnesota is $373.2 million for this account. The current approved life is a 39 years with a L0 dispersion curve. Life analysis results are based on total Company data. Company personnel report that insulators are made of porcelain and polymer. Polymer has only been used for the past 8-12 years, so there is limited experience. The primary reasons for retirements are overloads, tree issues, more than 2 splices in a span, and capacity issues. Life analysis shows a shorter life than poles with life increasing in the narrowest bands. Based on life analysis and judgment, a 39 year life with a L0 dispersion curve is recommended for this account. A comparison of actual versus simulated balances is shown below.



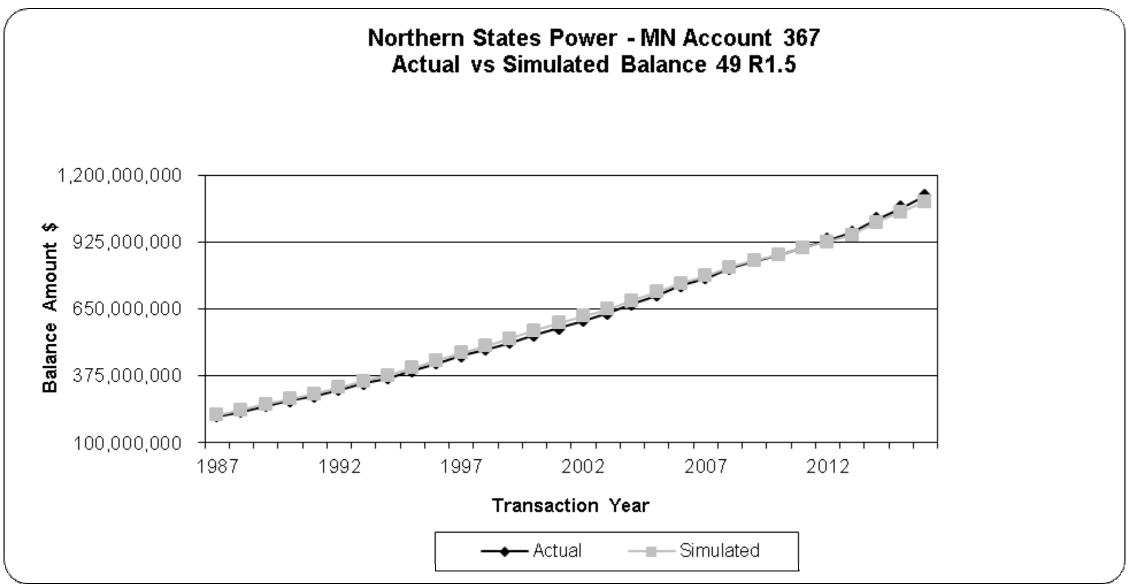
FERC Account 366 Distribution Underground Conduit (proposed 56 year life with a R3 dispersion curve)

This account consists of conduit, duct banks, vaults, manholes, and ventilating system equipment. The current investment balance for Minnesota is $261.3 million for this account. The current approved life is 52 years with a R3 dispersion curve. After reviewing SPR results, a mid-range dispersion appears is the best fit. After review of multiple bands, this study recommends a 56 year life while retaining the R3 dispersion curve. A comparison of the actual vs. simulated balances is shown below.



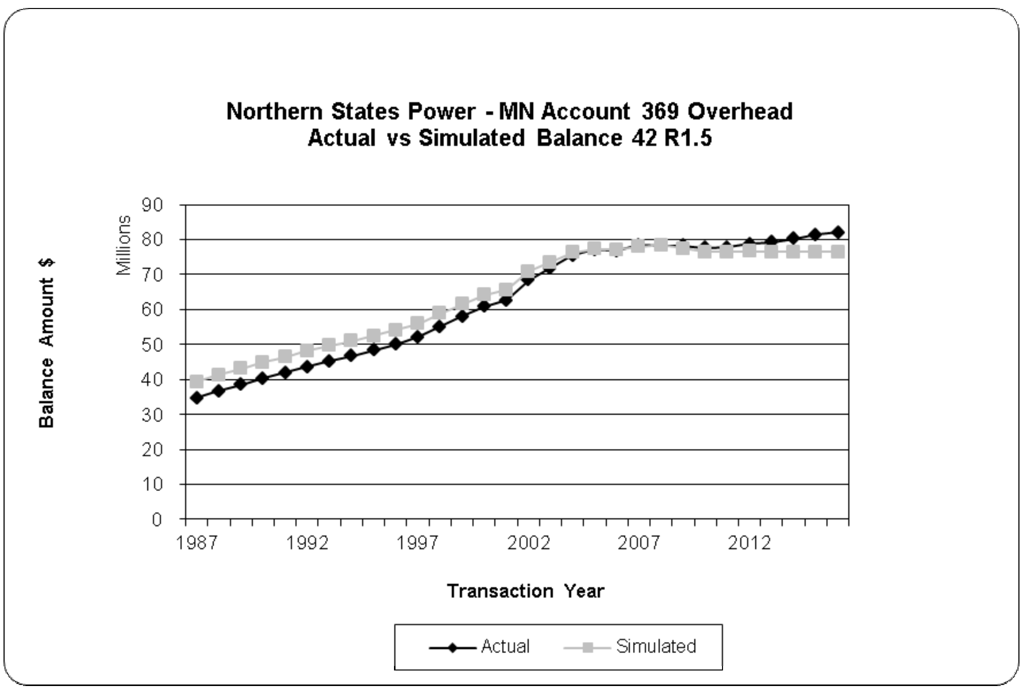
FERC Account 367 Distribution Underground Conductor & Devices (proposed 49 life with a R1.5 dispersion curve)

This account consists of underground distribution conductor, switches, and switchgear. The current investment balance for Minnesota is $967.9 million for this account. The currently approved life is a 45 years with a R2.5 dispersion curve. Life analysis results are based on total Company data. The SPR method was used to select the life parameter for this account. The best ranked curve with an REI of 100 across multiple bands was the 49 R1.5. After review of multiple bands, this study recommends a 49 year life while moving to a R1.5 dispersion curve. A comparison of the actual vs. simulated balances is shown below.



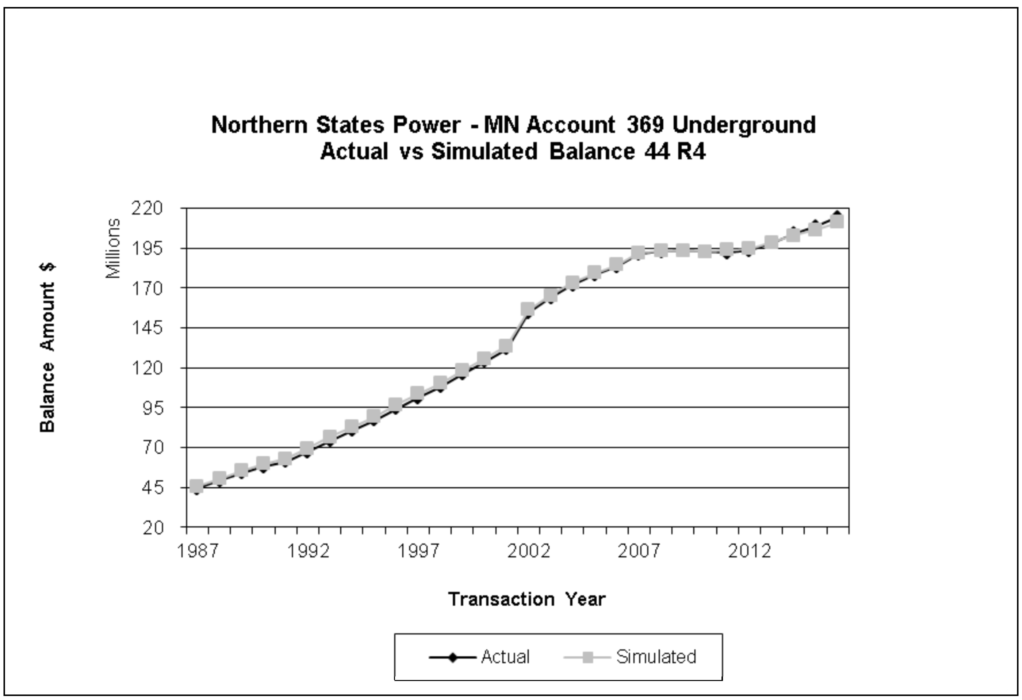
FERC Account 369 Distribution Services – Overhead (proposed 42 year life with a R1.5 dispersion curve)

This account includes overhead services with a current investment balance in Minnesota of $71.6 million. The current approved life is 40 years with a R1.5 dispersion. Life analysis results are based on total Company data. Company experts expect the life for services, both underground and overhead to be approximately 40 years. Many overhead services have been replaced for aesthetic reasons. After viewing SPR results and comparing actual versus simulated balances, a 42 year life with a R1.5 dispersion curve is recommended for this account.



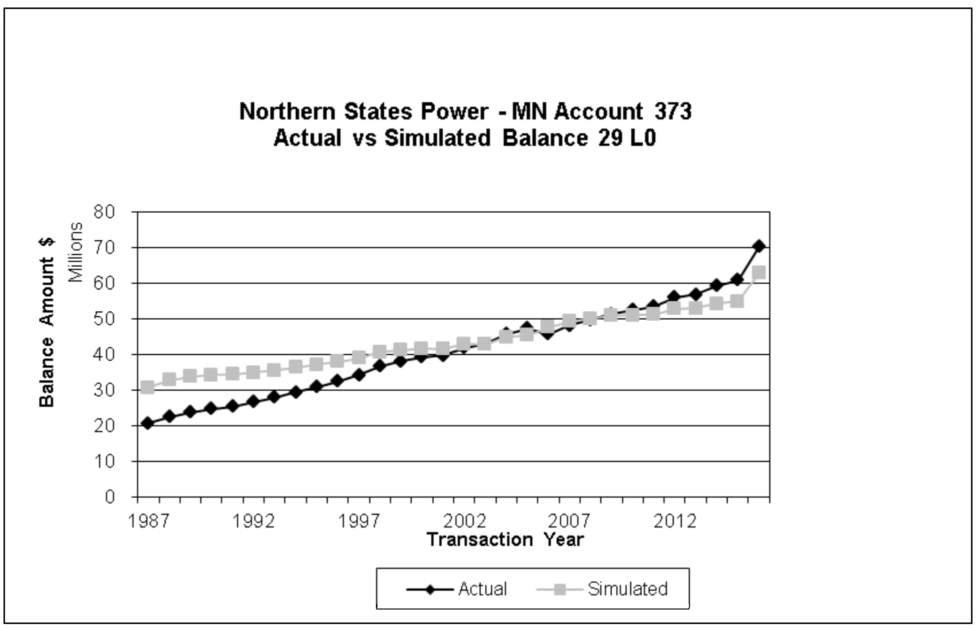
FERC Account 369 Distribution Services – Underground (proposed 44 year life with a R4 dispersion curve)

This account includes underground services and has a current investment balance in Minnesota of $185.8 million. The currently approved life is 41 years with a R4 dispersion curve. Life analysis results are based on total Company data. Company experts expect the life for services, both underground and overhead to be approximately 40 years. Better materials have been used for underground services since the 1970s. After viewing SPR results and comparing actual versus simulated balances, a 44 year life with a R4 dispersion curve is recommended for this account.



FERC Account 373 Distribution Street Lighting & Signal Systems (proposed 29 year life with a L0 dispersion curve)

This account includes all distribution streetlights, conductor, conduit, luminaire, and standards. The current investment balance for Minnesota is $64.2 million. The current approved life is 29 years with a L0 dispersion curve. Life analysis results are based on total Company data. SPR was used on this account, since actuarial results are only available from 2001 forward. The L0 is the top curve for many bands. As the band becomes narrower, the life increases. A comparison of the proposed curve vs. actual data is shown below. Based on judgment and Company experience, a 29 year life with a L0 dispersion curve is recommended for this account.

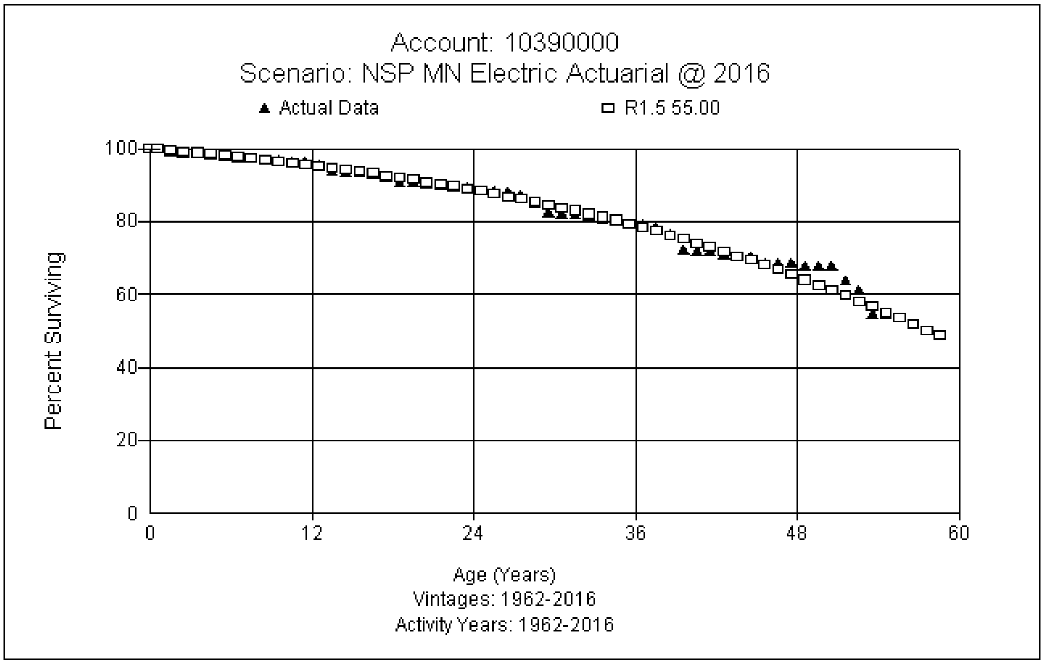


GENERAL

General Accounts, FERC Accounts 390

FERC Account 390 General Structures & Improvements (proposed 55 year life with a R1.5 dispersion curve)

This account includes the cost of general structures and improvements used for utility service. The current investment balance is $63.5 million. The current approved life is 57 years with a R1.5 dispersion curve. Many components such as heating, ventilation, and air conditioning ("HVAC") systems, lighting, controls, finishes, and roofing in buildings will have a much shorter life than the structure itself. Some consolidation of buildings occurs, but the Company redeploys buildings for other use when possible. Going forward, Company personnel expect to replace roofs at 20 years (currently have some that have only lasted 10 years and some that have lasted 25 years or longer) and anticipate the same time frame for HVAC (which would include boilers, cooling towers, chillers, etc.). Depending on the location (heat or heavy trucks can shorten life), parking lots would be expected to last 15-20 years. At that point, the Company would tear up the old lot, retire and replace it with a new one. Removal cost is charged for replacing lots – a fixed percentage that can change based on specific facts of the project. The average age of buildings is over 40 years. Based on the analysis and mix of assets, this study recommends moving to a 55 year life with a R1.5 dispersion curve.


Account: 10390000
Scenario: NSP MN Electric Actuarial @ 2016
Actual Data
R1.5 55.00
Percent Surviving
100
80
60
40
20
0
0
12
24
36
48
60
Age (Years)
Vintages: 1962-2016
Activity Years: 1962-2016

FERC Account 390 General Structures & Improvements - Leased (proposed 10 life with a SQ dispersion curve)

This account includes the cost of leasehold improvements used for utility service. There is approximately $36 thousand in this account which is fully accrued. The approved life for this account is 10 years with a SQ dispersion curve. Based on type of assets this study recommends retaining the existing 10 year life with a SQ dispersion curve. However, if the lease term changes the asset life should change accordingly. No graph is shown.

ELECTRIC VINTAGE GROUP (AMORTIZED) ACCOUNTS

For many years, NSP has used vintage group amortization where assets are large in number, but low in cost. To implement this amortization mechanism, it is necessary to first retire the assets whose age is longer than the recommended service life for each group are retired. Then, the remaining plant in service for each account is amortized using the amortization rates shown in Appendix A-1 and B. Annually, assets which reach the average service life of each account are retired when the assets reach their average service life. Thus no dispersion curve is used for assets being recovered through vintage group amortization.

DISTRIBUTION

FERC Account 368 Distribution Line Transformers (proposed 32 year life)

This account consists of line transformers and regulators. The current investment is $372.6 million for Minnesota in this account. The current approved life of 32 years should be retained.

FERC Account 368 Distribution Line Capacitors (proposed 25 year life)

This account consists of line capacitors. The current investment is $18.8 million for Minnesota in this account. However, $3.6 million is considered fully depreciated, so the adjusted balance is $15.2 million. The current approved life of 25 years should be retained.

FERC Account 370 Distribution Meters (proposed 15 year life)

This account includes new distribution meters. The current investment is $96.3 million for Minnesota. However, $42.0 million is considered fully depreciated, so the adjusted balance is $54.3 million. The current approved life of 15 years should be retained.

GENERAL PLANT VINTAGE GROUP (AMORTIZED) ACCOUNTS

FERC Account 303 Intangible Computer Software – 5 year (proposed 5 year life)

This account consists of miscellaneous computer software. The current investment is $115.2 million. However, $27.8 million is considered fully accrued so the adjusted balance is $87.4 million. The current approved life of 5 years should be retained.

FERC Account 391 General Office Furniture & Equipment (proposed 20 year life)

This account consists of miscellaneous office furniture such as desks, chairs, filing cabinets, and tables used for general utility service. The current investment is $27.6 million. The current approved life of 20 years should be retained.

FERC Account 391 General Network Equipment (proposed 6 year life)

This account consists of computer equipment used for general utility service. The current investment is $32.4 million. The currently approved life is 4 years. Interviews with Company personnel show this equipment is lasting longer, and this study recommends moving to a 6 year life for this account.

FERC Account 392 General Transportation Equipment - Automobiles (proposed 10 year life)

This account consists of automobiles used for general utility service. The current investment is $1.1 million. The current approved life of 10 years should be retained.

FERC Account 392 General Transportation Equipment - Light Trucks (proposed 10 year)

This account consists of light trucks used for general utility service. The current investment is $32.8 million. However, $6.2 million is considered fully accrued so the adjusted balance is $26.6 million. The current approved life is 12 years. Interviews with Company personnel show they are retiring light trucks earlier than in the past; therefore, this study recommends moving to a 10 year life for this account.

FERC Account 392 General Transportation Equipment - Trailers (proposed 12 year life)

This account consists of trailers used for general utility service. The current investment is $17.9 million. The current approved life is 15 years. Interviews with Company personnel show they are retiring trailers earlier than in the past; therefore, this study recommends moving to a 12 year life for this account.

FERC Account 392 General Transportation Equipment - Heavy Trucks (proposed 12 year)

This account consists of heavy trucks used for general utility service. The current investment is $97.6 million. However, $4.1 million is considered fully accrued so the adjusted balance is $93.5 million. The current approved life is 14 years. Interviews with Company personnel show they are retiring heavy trucks earlier than in the past; therefore, this study recommends moving to a 12 year life for this account.

FERC Account 393 General Stores Equipment (proposed 20 year)

This account consists of stores equipment used for general utility service. The current investment is $1.6 million. The current approved life of 20 years should be retained.

FERC Account 394 General Tools, Shop & Garage Equipment (proposed 15 year life)

This account consists of various items or tools used in shop and garages such as air compressors, grinders, mixers, hoists, and cranes. The current investment is $81.3 million. However, $188 thousand is considered fully accrued so the adjusted balance is $81.1 million. The current approved life of 15 years should be retained.

FERC Account 395 General Laboratory Equipment (proposed 10 year life)

This account consists of laboratory equipment used in general utility service. The current investment is $3.2 million. The current approved life of 10 years should be retained.

FERC Account 396 General Power Operated Equipment (proposed 12 year life)

This account consists of bulldozers, forklifts, trenchers, and other power operated equipment that cannot be licensed on roadways. The current investment is $45.1 million. The current approved life is 12 years should be retained.

FERC Account 397 General Communication Equipment (proposed 10 year life)

This account consists of miscellaneous communication equipment used in general utility service. The current investment is $17.1 million. However, $159 thousand is considered fully accrued so there will be an adjusted balance of $16.9 million. The current approved life of 9 years. Interviews with Company personnel show this equipment is lasting longer, and this study recommends moving to a 10 year life for this account.

FERC Account 397 General Communication Equipment – Two Way (proposed 10 year life)

This account consists of miscellaneous two way communication equipment used in general utility service. The current investment is $6.5 million. The current approved life is 9 years. Interviews with Company personnel show this equipment is lasting longer, and this study recommends moving to a 10 year life for this account.

FERC Account 397 General Communication Equipment – AES (proposed 15 year life)

This account consists of miscellaneous automated energy services ("AES") including electronic or automated meter reading communication equipment used in general utility service. The current investment is $7.1 million. The current approved life of 15 years should be retained.

FERC Account 397 General Communication Equipment – EMS (proposed 15 year life)

This account consists of energy management system ("EMS") communication equipment used for energy monitoring and controlling equipment to manage general utility service. The current investment is $47.3 million. The current approved life of 15 years should be retained.

FERC Account 398 General Miscellaneous Equipment (proposed 15 year life)

This account consists of miscellaneous equipment used in general utility service. The current investment is $2.72 million. However, $66 thousand is considered fully accrued so there will be an adjusted balance of $2.66 million. The current approved life of 15 years should be retained.

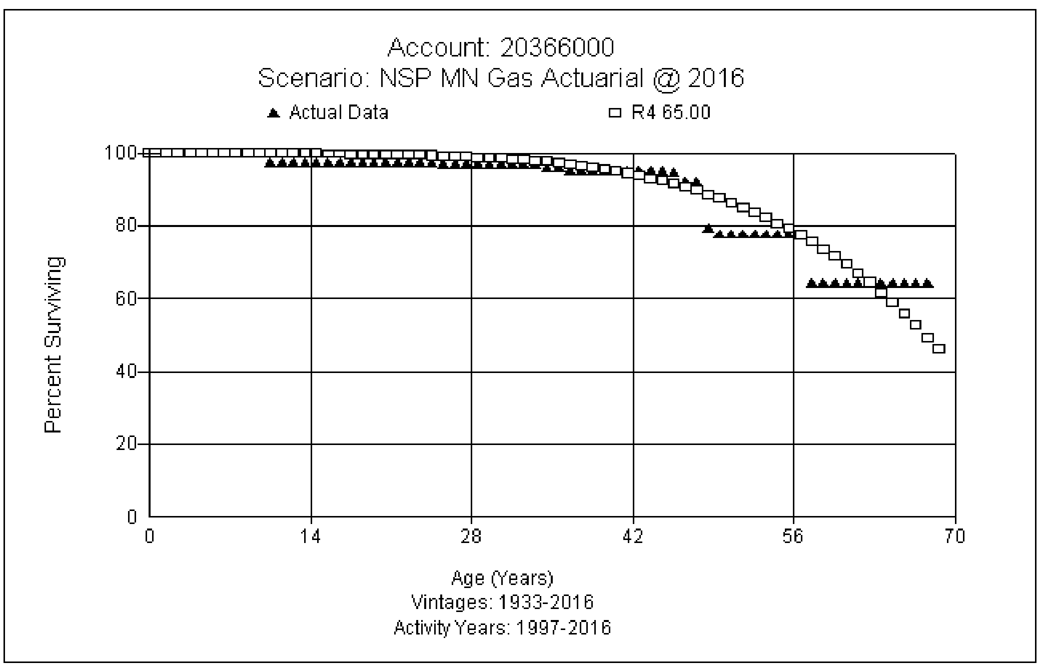
GAS PLANT

TRANSMISSION

Transmission Accounts, FERC Accounts 366 - 369

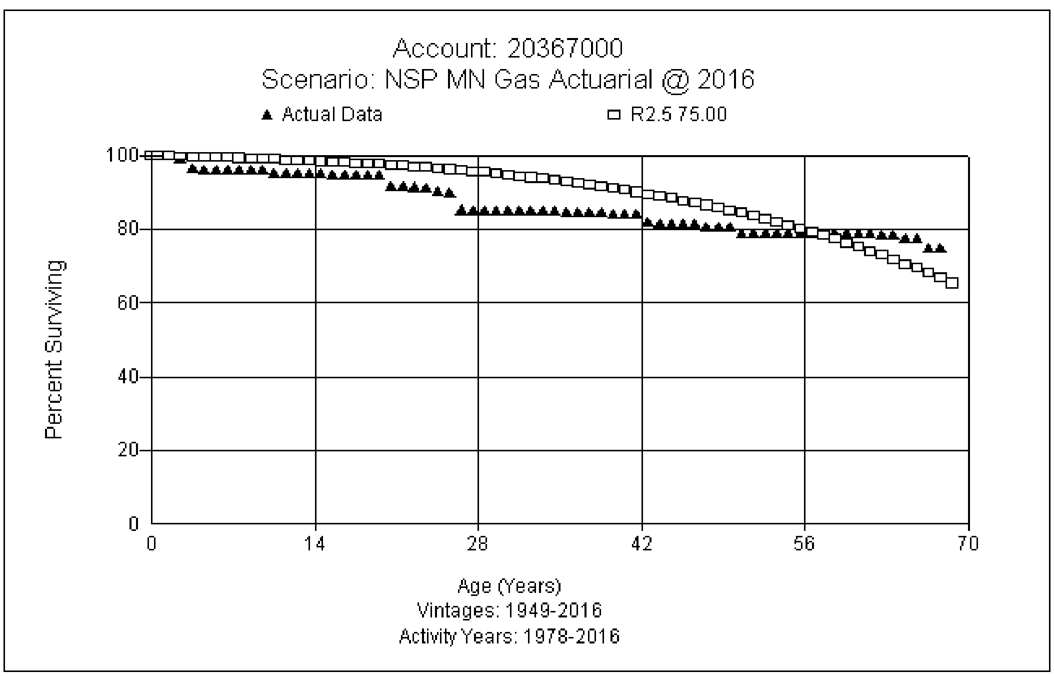
FERC Account 366 Transmission Structures & Improvements (proposed 65 year life with a R4 dispersion curve)

This account includes the cost of structures and improvements used in conjunction with transmission operations such as buildings, fences, or other structures. The plant balance in this account is $1.1 million. The current approved life is 52 years with a R3 dispersion curve. Life analysis shows a longer life. Based on actuarial analysis, a 65 year life with a R4 dispersion curve is recommended. A graph of the observed life table vs. the proposed life and curve is shown below.



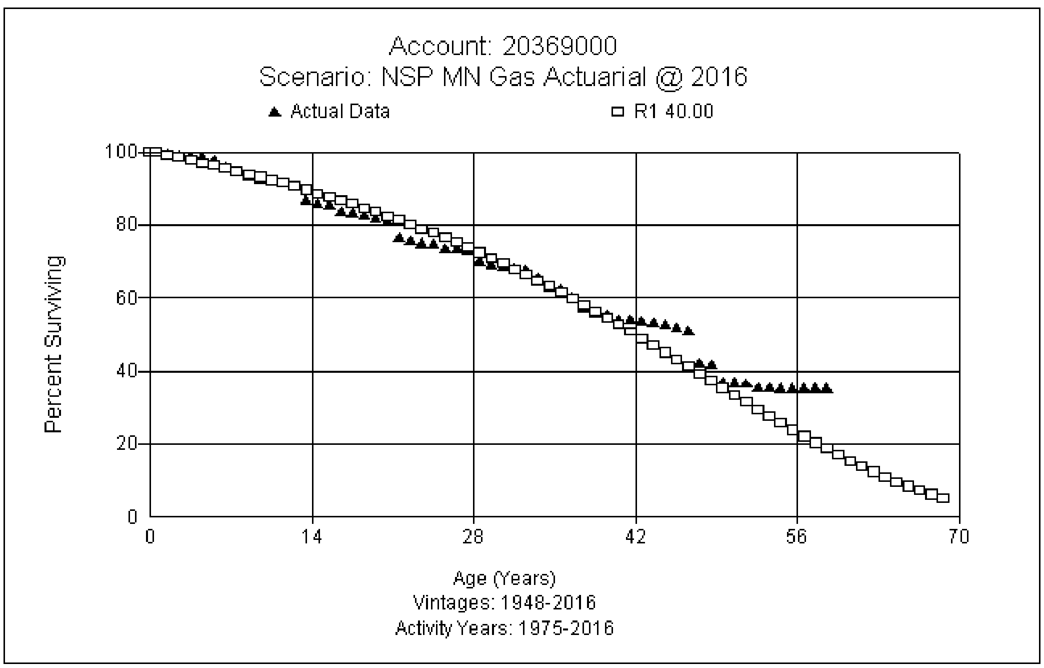
FERC Account 367 Transmission Mains (proposed 75 year life with a R2.5 dispersion curve)

This account includes the cost of transmission system mains including excavation costs, pipe, valves, and other equipment. The plant balance in this account is $65.8 million. The current approved life is 75 years with a R2.5 dispersion curve. There are only 100 miles of transmission mains in Minnesota – nothing older than 1940s (very few miles prior to 1950s). A large project started in 2013 to replace nearly 15% of the transmission pipe (pressure coupled). Much of it was installed in late 1960s and early 1970s. For the existing asset base, 13 miles was installed in the 1940s, 27 miles in 1950s, 6 miles in the 60s, 10 miles in the70s, 3 miles in the 80s, 13 miles in the 1990s (1995), with the rest being newer. Based on actuarial analysis and the mix of assets, this study recommends retaining a 75 year life with a R2.5 dispersion curve. A graph of actual data versus the proposed curve is shown below.



FERC Account 369 Transmission Measure & Regulating Station Equipment (proposed 40 year life with a R1 dispersion curve)

This account includes the costs of meters, gauges, and other equipment used to measure or regulate gas in connection with transmission city gate (town border station) operations. The plant balance in this account is $13.6 million. The current approved life is 33 years with a R1.5 dispersion curve. Measurement equipment is replaced as technology improves – (e.g. from mercury meters, to chart recorders, to electronic flow meters). Life indications across various placement and experience bands show the 40 R1 to be a good match. Based on actuarial analysis and the mix of assets, this study recommends moving to a 40 year life with a R1 dispersion curve. A graph of actual data versus the proposed curve is shown below.

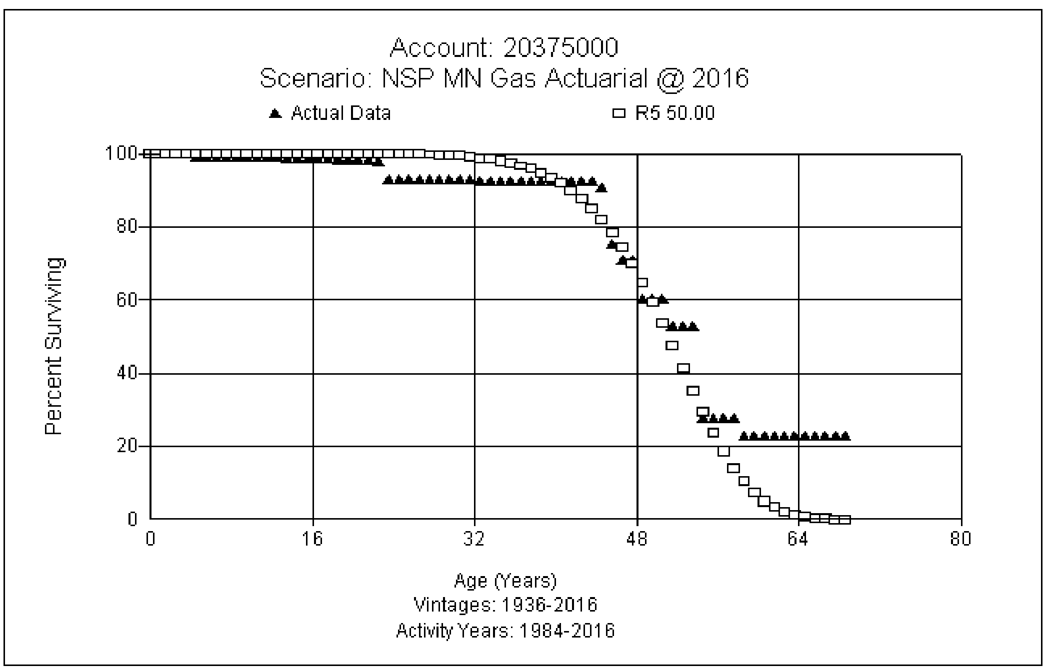


DISTRIBUTION

Distribution Accounts, FERC Accounts 375 - 380

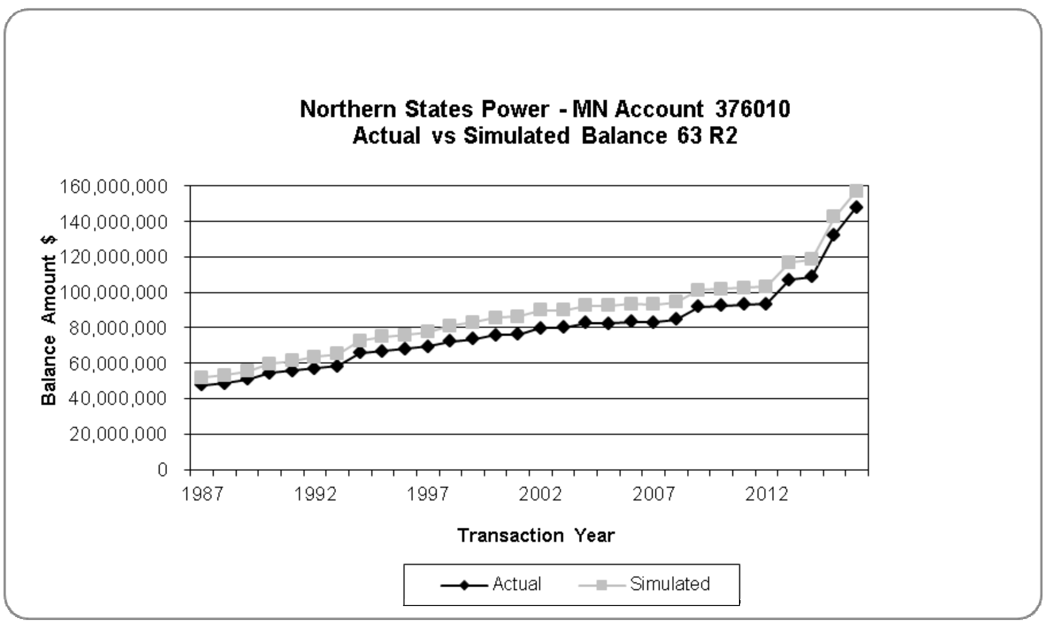
FERC Account 375 Distribution Structures & Improvements (proposed 50 year life with a R5 dispersion curve)

This account consists of small structures and improvements to such structures and associated assets at city gates and on the main line distribution system. The current investment is $728 thousand for Minnesota. The current approved life is 41 year life with a R5 dispersion curve. Based on judgment and general expectations for structures, this study recommends moving to a 50 year life while retaining the R5 dispersion curve for this account. A graph of actual data versus the proposed curve is shown below.



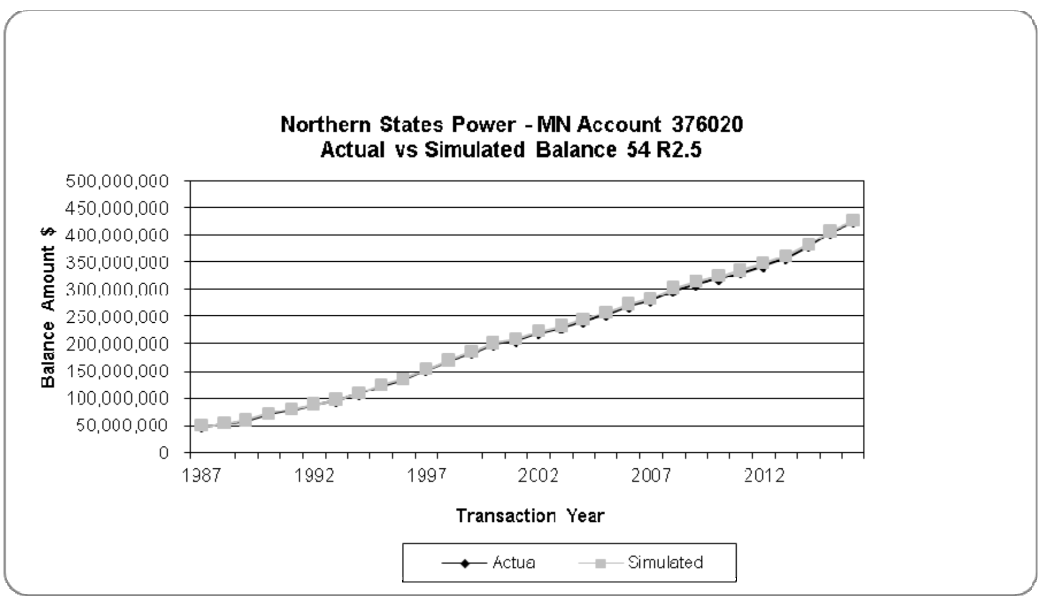
FERC Account 376 Distribution Mains – Metallic (proposed 63 year life with a R2 dispersion curve)

This account includes all steel mains. The current approved life is 51 years with a R1.5 dispersion curve. The current investment balance for Minnesota is $135.1 million for this account. Life analysis results are based on total Company data. The average age of facilities is younger than many other utilities driven by growth in the mid to late 1990s. Actuarial data only exists from 2001 forward. SPR analysis shows a longer life in more recent periods. Based on judgment, this study recommends a change to a 63 year life with a R2 dispersion curve for this account. A comparison of actual versus simulated balances is shown below for the 63 year life with a R2 dispersion curve.



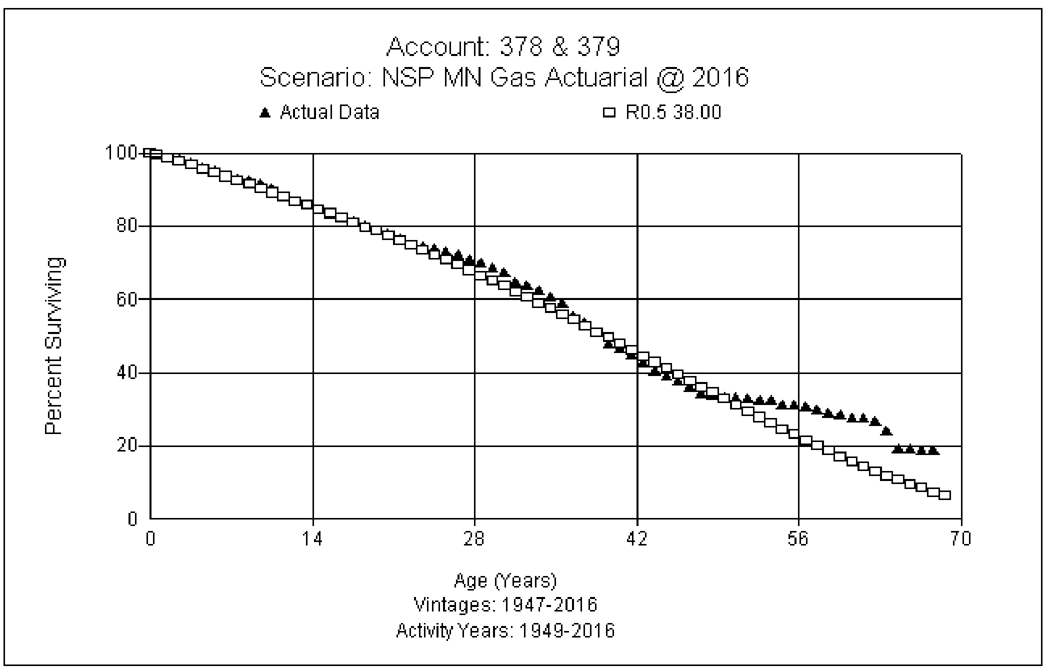
FERC Account 376 Distribution Mains – Plastic (proposed 54 year life with a R2.5 dispersion curve)

This account includes all plastic mains. The current approved life is 45 years with a R2.5 dispersion curve. The current investment balance for Minnesota is $384.4 million for this account. Life analysis results are based on total Company data. Company personnel report that 99% of new distribution mains are plastic. The Company is aggressively replacing pre 1960's assets, with early 1970's polyethylene targeted next. Actuarial data only exists from 2001 forward. SPR analysis shows a similar life to the existing approved life. Based on judgment, this study recommends a 54 year life with a R2.5 dispersion curve. A comparison of actual versus simulated balances is shown below for the 54 year life and R2.5 dispersion curve.



FERC Account 378 Distribution Measure & Regulating Station Equipment – General (proposed 38 year life with a R0.5 dispersion curve)

This account consists of meters, gauges, and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries city gate and to customers. The current approved life is a 38 year life with a R0.5 dispersion curve. The current investment balance for Minnesota is $22.8 million for this account. Life analysis results are based on total Company data. Consistent with the last depreciation study, this study combines the assets in Account 378 and 379 due to the similarity between the assets in each account. Actuarial analysis showed that a 38 year life with a R0.5 dispersion curve is a good match across the various experience bands. This study recommends retaining the existing 38 year life with a R0.5 dispersion. A graph of actual data versus the proposed curve is shown below.

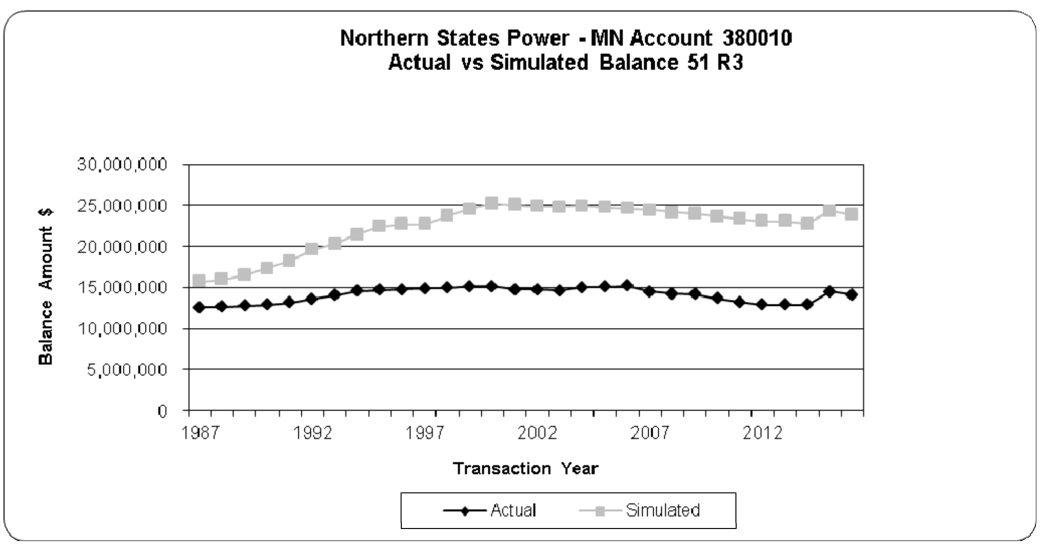


FERC Account 379 Distribution Measure & Regulating Station Equipment - City Gate (proposed 38 year life with a R0.5 dispersion curve)

This account includes the measuring and regulating devices and other apparatus at city gate stations. There is a current investment of $1.4 million for Minnesota in this account. The current approved life is a 38 year life with a R0.5 dispersion curve. Consistent with the prior study Account 378 and 379 were combined for life analysis purposes due to the similarity of the assets, similarity of use and expected lives. The resulting recommendation is a 38 year life with a R0.5 dispersion curve for both accounts. A graph of actual data versus the proposed curve is shown above in Account 378.

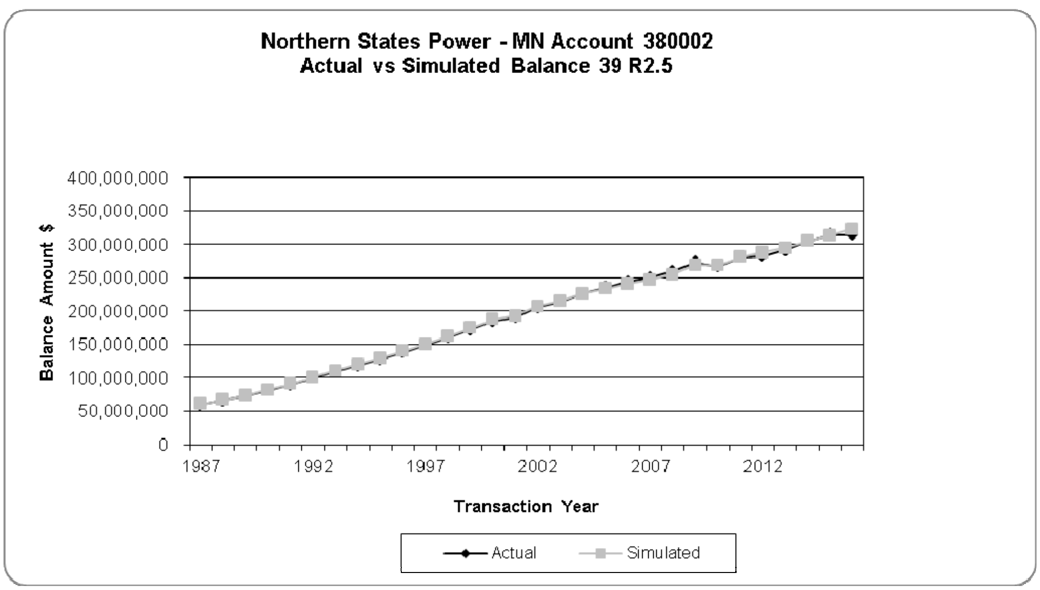
FERC Account 380 Distribution Services - Metallic (proposed 51 year life with a R3 dispersion curve)

Service lines are the steel pipes and accessories leading from the main to the customers' premises. This account has a current investment of $12.6 million for Minnesota. The current approved life is 40 years with a S3 dispersion curve. Life analysis results are based on total Company data. Age is the primary driver of retirement of services. In a renewal area (road or otherwise), the practice is to renew all services when mains are renewed. Normal processes also trigger replacements (e.g. leak issues or compression coupled). Since actuarial data exists only for 2001 forward, this account was analyzed using SPR. Life analysis results show a longer life for this account than is currently approved. Since processes are in place to improve life expectations in this account, this study recommends moving to a 51 year life and R3 dispersion curve for this account. A comparison of actual versus simulated balances is shown below for the 51 R3 curve.



FERC Account 380 Distribution Services - Plastic (proposed 39 year life with a R2.5 dispersion curve)

Service lines are the plastic pipes and accessories leading from the main to the customers' premises. This account has a current investment of $272.7 million for Minnesota. Life analysis results are based on total Company data. The current approved life is 39 R2.5. Since actuarial data exists only for 2001 forward, this account was analyzed using SPR. Life analysis results show a similar life to the existing approved life for this account. This study recommends retaining the existing 39 year life with a R2.5 dispersion curve for this account. A comparison of actual versus simulated is shown for the proposed 39 year life and R2.5 dispersion curve.

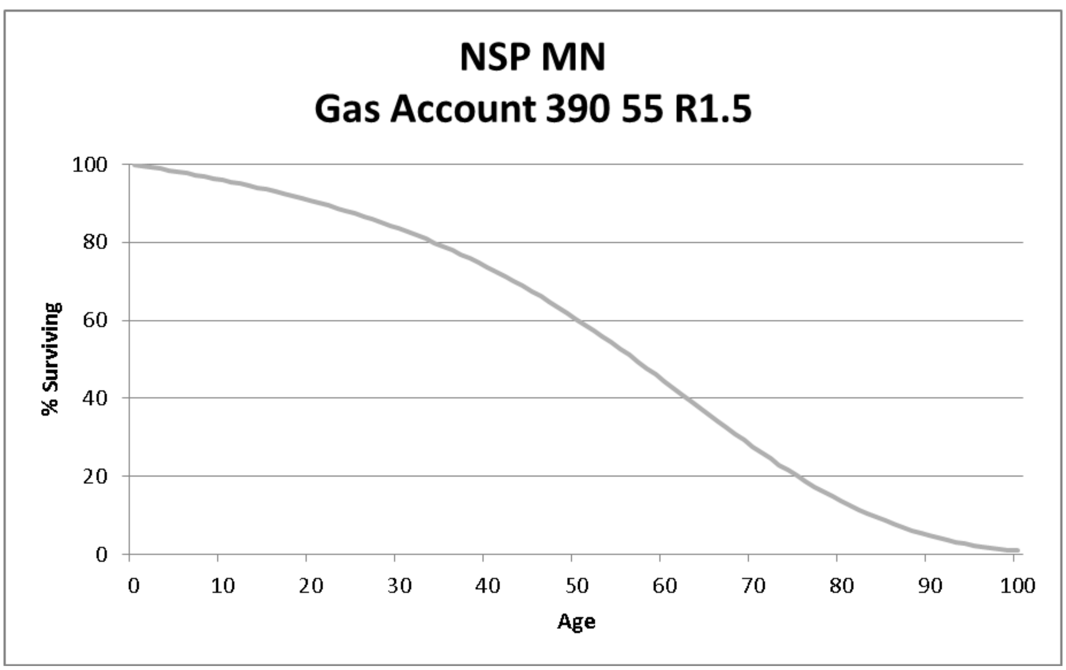


GENERAL

General Accounts, FERC Accounts 390

FERC Account 390 General Structures & Improvements (proposed 55 year life with a R1.5 dispersion curve)

This account includes the cost of general structures and improvements used for utility service. The current investment balance is $1.5 million. The current approved life is 55 years with a R1.5 dispersion curve. Gas mortality data in this account shows a shorter life than currently approved, but this trend is not expected to continue. Based on judgment, this study proposes to retain the existing 55 year life with a R1.5 dispersion curve for this account. A graph of the proposed curve for this account is shown below.



GAS VINTAGE GROUP (AMORTIZED) ACCOUNTS

GAS DISTRIBUTION

Account 381 Distribution Meters (proposed 20 year life)

This account includes the cost of meters and house regulators installed after 1994. The current investment is $105.1 million for Minnesota. However, $12.9 million is considered fully accrued and results in an adjusted study balance of $92.2 million. The current approved life of 20 years should be retained.

Account 381 Distribution Meters - Telemetering (proposed 8 year life)

This account includes the cost of telemetering assets. The current investment is $37 thousand for Minnesota. However, the current investment is fully amortized. The current approved life of 8 years should be retained. This analysis is for any future investment in this account.

Account 383 Distribution House Regulators (proposed 20 year life)

This account includes the cost of house regulators installed before 1995 that were not combined with the meter account. The current investment is $10.1 million for Minnesota. The current approved life of 20 years should be retained.

GAS GENERAL PLANT VINTAGE GROUP (AMORTIZED) ACCOUNTS

The same life parameters used for electric plant are proposed for amortized gas plant due to the similar operations and policies. The table below summarizes recommendations and plant balances by account.

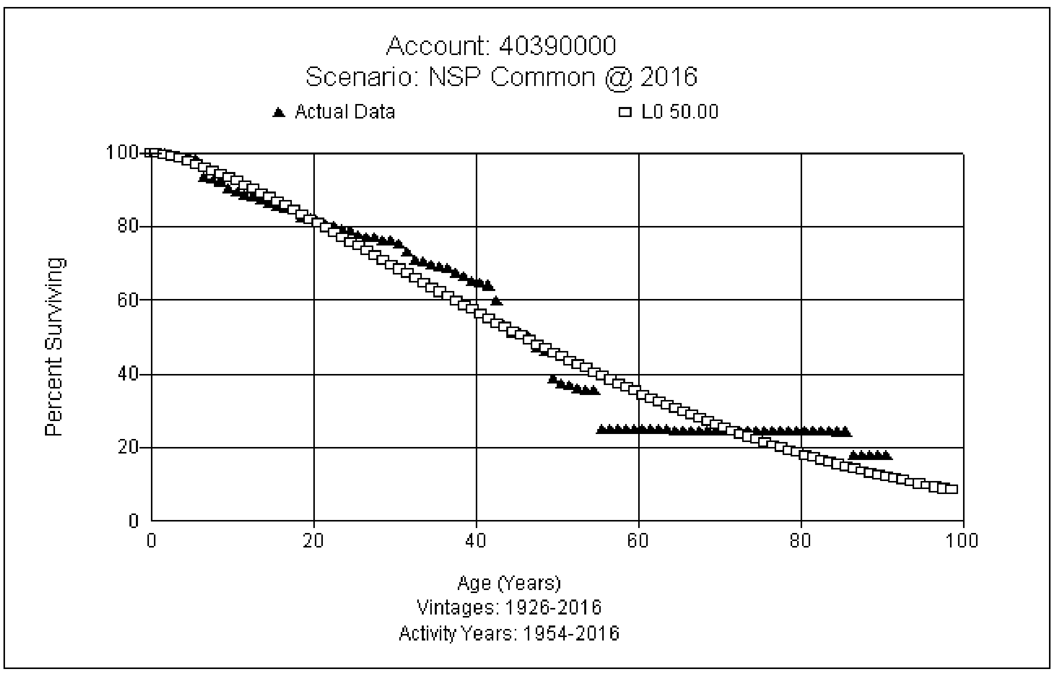
Acct	Description	Plant $ x 000	Fully Accrued $ x 000	Adjusted $ x 000	Current Life	Proposed Life
Intangible						
303	Computer Software - 5 Year	7,256.6	3,062.6	4,194.0	5	5
303	Computer Software – 10 Year	234.3	0.0	234.3	10	10
General Plant						
391	Office Furniture & Equipment	906.4	0.0	906.4	20	20
391	Network Equipment	38.0	0.0	38.0	4	6
392	Transportation Equipment - Automobiles	376.9	0.0	376.9	10	10
392	Transportation Equipment – Light Trucks	6,054.5	847.5	5,207.0	12	10
392	Transportation Equipment - Trailers	1,504.1	50.3	1,453.8	15	12
392	Transportation Equipment - Heavy Trucks	8,425.9	725.1	7,700.8	14	12
393	Stores Equipment	10.1	0.0	10.1	20	20
394	Tools, Shop & Garage Equipment	6,257.8	59.1	6,198.7	15	15
395	Laboratory Equipment	0.0	0.0	0.0	10	10
396	Power Operated Equipment	2,858.2	0.0	2,858.2	12	12
397	Communication Equipment	4,722.3	0.0	4,722.3	9	10
397	Communication Equipment – Two Way	120.1	0.0	120.1	9	10
397	Communication Equipment - AES	15,492.8	0.0	15,492.8	15	15
397	Communication Equipment - EMR	764.4	0.0	764.4	15	15
398	Miscellaneous Equipment	50.7	0.0	50.7	15	15

COMMON UTILITY PLANT DEPRECIATED ACCOUNTS

General Accounts, FERC Accounts 390

FERC Account 390 General Structures & Improvements (proposed 50 year life with a L0 dispersion curve)

This account includes the cost of general structures and improvements used for utility service. There is approximately $151.8 million in this account. The approved life for this account is 55 years and a R1.5 dispersion curve. Based on actuarial analysis, this study recommends moving to a 50 year life with a L0 dispersion curve.



FERC Account 390 General Structures & Improvements - Leased (proposed 10 life with a SQ dispersion curve)

This account includes the cost of leasehold improvements used for utility service. There is approximately $18.5 million in this account for one property where the lease is set to expire June 2026. The approved life for this account is 10 years with a SQ dispersion curve. Based on type of assets this study recommends retaining the existing 10 year life with a SQ dispersion curve. However, if the lease term changes the asset life should change accordingly. No graph is shown.

GENERAL PLANT VINTAGE GROUP (AMORTIZED) ACCOUNTS

The same life parameters used for electric and gas plant are proposed for amortized common plant due to the similar operations and policies with the exception of Account 391 Network Equipment. In Common plant, there are a large number of laptops booked in this account and a 5 year life is recommended for Common plant. The table below summarizes recommendations and plant balances by account.

Acct	Description	Plant $ x 000	Fully Accrued $ x 000	Adjusted $ x 000	Current Life	Proposed Life
Intangible						
303	Computer Software - 3 Year	7,673.5	7,673.5	0.0	3	3
303	Computer Software - 5 Year	197,541.3	87,306.0	110,232.3	5	5
303	Computer Software - 7 Year	44,140.6	44,140.6	0.0	7	7
303	Computer Software - 10 Year	68,449.2	58,267.7	10,181.5	10	10
303	Computer Software - 15 Year	61,015.4	0.0	61,015.4	15	15
General Plant						
391	Office Furniture & Equipment	27,141.6	2,929.1	24,212.5	20	20
391	Network Equipment	100,446.2	3.3	100,442.9	4	5
392	Transportation Equipment - Automobiles	823.5	0.0	823.5	10	10
392	Transportation Equipment - Light Trucks	3,431.5	25.3	3,406.2	12	10
392	Transportation Equipment - Trailers	1,099.7	104.3	995.3	15	12
392	Transportation Equipment - Heavy Trucks	5,505.4	1,252.3	4,253.1	14	12
393	Stores Equipment	246.2	0.0	246.2	20	20
394	Tools, Shop & Garage Equipment	4,041.7	10.9	4,030.8	15	15
395	Laboratory Equipment	0.0	0.0	0.0	10	10
396	Power Operated Equipment	990.9	281.2	709.7	12	12
397	Communication Equipment	964.4	248.6	715.8	9	10
397	Communication Equipment - Two Way	75.1	0.0	75.1	9	10
398	Miscellaneous Equipment	582.2	0.0	582.2	15	15

Salvage Analysis

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the timing of the original addition versus the retirement.

The net salvage analysis uses the history of the individual accounts to estimate the future net salvage that NSP can expect in its operations. This study also removes reimbursements for relocations that may have been booked to gross salvage. Any associated retirements are also removed from the data for consistency. As a result, the analysis not only looks at the historical experience of NSP, but also takes into account recent and expected changes in operations that could reasonably lead to different future expectations for net salvage than were experienced in the past.

Salvage Characteristics

For most accounts, data for retirements, gross salvage, and cost of removal for each account is available from 1950-2016. Some accounts have shorter periods with available data. Moving averages, which remove timing differences between retirement and salvage and removal cost, were analyzed over periods varying from two to 10 years.

ELECTRIC PLANT

TRANSMISSION

Transmission Accounts, FERC Accounts 352-358

FERC Account 352 Transmission Structures & Improvements (proposed negative 5 percent net salvage)

This account consists of any gross salvage and cost of removal associated transmission structures and improvements which include buildings, fencing and other structures found in a transmission substation. The approved net salvage for this account is 0 percent. The most recent moving averages show negative net salvage and increased costs of removal due to changes in capacity and station reconfiguration. Taking that into consideration, negative 5 percent net salvage for this account is recommended.

FERC Account 353 Transmission Station Equipment (proposed negative 15 percent net salvage)

This account consists of any gross salvage and cost of removal associated with transmission substation equipment, from circuit breakers to switchgear. The approved net salvage for this account is negative 10 percent. The most recent 5 and 10 year moving averages show negative 16.93 percent and negative 20.10 percent net salvage respectively. Moving in the direction of that trend, negative 15 percent net salvage for this account is recommended.

FERC Account 354 Transmission Towers & Fixtures (proposed negative 35 percent net salvage)

This account consists of any gross salvage and cost of removal associated with transmission towers and fixtures, which are used to transmit electricity at a voltage of 69 kV and above. This study recommends the current approved net salvage of negative 35 percent should be retained.

FERC Account 355 Transmission Poles & Fixtures (proposed negative 50 percent net salvage)

This account consists of any gross salvage and cost of removal associated with transmission poles and fixtures, which are used to transmit electricity at a voltage of 69 kV and above. The approved net salvage for this account is negative 35 percent. The most recent 5 and 10 year moving averages show negative 108.84 percent and negative 105.28 percent net salvage respectively. Moving in the direction of that trend, negative 50 percent net salvage for this account is recommended.

FERC Account 356 Transmission Overhead Conductor & Devices (proposed negative 35 percent net salvage)

This account consists of any gross salvage and cost of removal associated with Transmission overhead conductors, which are used to transmit electricity at voltages of 69 kV and above. The approved net salvage for this account is negative 30 percent. The most recent 5 and 10 year moving averages show negative 69.71 percent and negative 41.68 percent net salvage respectively. Moving in the direction of that trend, negative 35 percent net salvage for this account is recommended.

FERC Account 357 Transmission Underground Conduit (proposed 0 percent net salvage)

This account consists of any gross salvage and cost of removal associated with underground conduit. The approved net salvage for this account is 0 percent. There is limited retirement and net salvage activity in recent years. . Based on judgment, retention of 0 percent net salvage for this account is recommended.

FERC Account 358 Transmission Underground Conductor & Devices (proposed negative 5 percent net salvage)

This account consists of any gross salvage and cost of removal associated with underground conductor. The lines are low pressure oil filled; paper wrapped 500 MCM copper cable. The approved net salvage for this account is 0 percent. Data is limited for this account. The most recent 5 and 10 year moving averages show negative 132.36 percent and negative 16.03 percent net salvage, respectively. Retirement data is limited for this account, however removal costs are sometimes quite high when retirements occur; therefore, moving to negative 5 percent net salvage for this account is recommended.

DISTRIBUTION

Distribution Accounts, FERC Accounts 361 - 373

FERC Account 361 Distribution Structures & Improvements (proposed negative 30 percent net salvage)

This account contains any gross salvage and cost of removal associated with facilities ranging from fencing to other structures found in distribution substations. The approved net salvage for this account is negative 30 percent. The most recent 5 and 10 year moving averages show negative 196.40 percent and negative 139.35 percent net salvage respectively. Since there is a low level of retirement data and it is sporadic for this account, retention of negative 30 percent net salvage for this account is recommended.

FERC Account 362 Distribution Station Equipment (proposed negative 25 percent net salvage)

This account contains any gross salvage and cost of removal associated with a wide variety of distribution substation equipment, from circuit breakers to switchgear. The approved net salvage for this account is negative 20 percent The most recent 5 and 10 year moving averages show negative 26.77 percent and negative 26.68 percent net salvage respectively. Moving in the direction of that trend, negative 25 percent net salvage for this account is recommended.

FERC Account 364 Distribution Poles, Towers & Fixtures (proposed negative

120 percent net salvage)

This account contains any gross salvage and cost of removal associated with poles and towers of various material types: wood and steel. The approved net salvage for this account is negative 100 percent. The most recent 5 and 10 year moving averages show negative 255.40 percent and negative 244.52 percent net salvage respectively. Moving in the direction of that trend, negative 120 percent net salvage for this account is recommended.

FERC Account 365 Distribution Overhead Conductor & Devices (proposed negative 25 percent net salvage)

This account consists of any gross salvage and cost of removal associated with overhead conductor of various thickness, as well as various switches and reclosers. The approved net salvage for this account is negative 20 percent. The most recent 5 and 10 year moving averages show negative 44.23 percent and negative 33.49 percent net salvage respectively. Moving in the direction of that trend, negative 25 percent net salvage for this account is recommended.

FERC Account 366 Distribution Underground Conduit (proposed negative 20 percent net salvage)

This account consists of any gross salvage and cost of removal associated with conduit, duct banks, vaults, manholes, and ventilating system equipment. The approved net salvage for this account is negative 10 percent. The most recent 5 and 10 year moving averages show negative 276.23 percent and negative 89.75 percent net salvage respectively. Moving in the direction of that trend, negative 20 percent net salvage for this account is recommended.

FERC Account 367 Distribution Underground Conductor & Devices (proposed negative 10 percent net salvage)

This account consists of any gross salvage and cost of removal associated with underground distribution conductor, switches, and switchgear. The approved net salvage for this account is 0 percent. The most recent 5 and 10 year moving averages show negative 45.44 percent and negative 26.99 percent net salvage respectively. Moving in the direction of that trend, a negative 10 percent net salvage for this account is recommended.

FERC Account 369 Distribution Services – Overhead (proposed negative 85 percent net salvage)

This account includes any gross salvage or cost of removal associate with overhead services. The approved net salvage for this account is negative 70 percent. The last depreciation study combined data for overhead and underground services, whereas this study separates the two. The most recent 5 and 10 year moving averages show negative 163.18 percent and negative 127.99 percent net salvage respectively. Moving in the direction of that trend, negative 85 percent net salvage for this account is recommended.

FERC Account 369 Distribution Services – Underground (proposed negative 5 percent net salvage)

This account includes any gross salvage and cost of removal associated with underground services. The approved net salvage for this account is negative 5 percent. The last study combined data for overhead and underground services, whereas this study separates the two. The most recent 5 and 10 year moving averages show negative 50.02 percent and negative 7.72 percent net salvage respectively. Retaining the existing negative 5 percent net salvage for this account is recommended.

FERC Account 373 Distribution Street Lighting & Signal Systems (proposed negative 40 percent net salvage)

This account includes any gross salvage and cost of removal associated with distribution streetlights, conductor, conduit, luminaire, and standards. The approved net salvage for this account is negative 35 percent. The most recent 5 and 10 year moving averages show negative 90.29 percent and negative 91.90 percent net salvage respectively. Moving in the direction of that trend, negative 40 percent net salvage for this account is recommended.

GENERAL

General Accounts, FERC Accounts 390

FERC Account 390 General Structures & Improvements (proposed negative 20 percent net salvage)

This account includes the any gross salvage and cost of removal associated with cost of general structures and improvements used for utility service. The approved net salvage for this account is negative 20 percent. The most recent 5 and 10 year moving averages show negative 15.70 percent and negative 19.32 percent net salvage respectively. Retaining the existing, negative 20 percent net salvage for this account is recommended.

ELECTRIC VINTAGE GROUP (AMORTIZED) ACCOUNTS

DISTRIBUTION

FERC Account 368 Distribution Line Transformers (proposed negative 5 percent net salvage)

This account consists of any gross salvage and cost of removal associated with line transformers and regulators. The approved net salvage for this account is negative 5 percent. The most recent 5 year moving averages shows negative 10.45 and negative 9.37 percent respectively. Removal and salvage vary fairly significantly over time. Therefore, retaining negative 5 percent net salvage for this account is recommended.

FERC Account 368 Distribution Line Capacitors (proposed negative 7 percent net salvage)

This account consists of line capacitors. The approved net salvage for this account is negative 10 percent. The most recent 5 and 10 year moving averages show negative 4.18 percent and negative 6.77 percent net salvage respectively. Moving in the direction of that trend, negative 7 percent net salvage for this account is recommended.

FERC Account 370 Distribution Meters (proposed negative 5 percent net salvage)

This account includes any gross salvage and cost of removal associated with new distribution meters. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show negative 7.99 percent and negative 11.77 percent net salvage respectively. Moving in the direction of that trend, negative 5 percent net salvage for this account is recommended.

FERC Account 370 Distribution Meters – Old (proposed zero percent net salvage)

This account includes any gross salvage and cost of removal associated with all old distribution meters. The approved net salvage for this account is zero percent. Limited data shows zero percent net salvage for this account. Thus, retention of zero percent net salvage for this account is recommended.

GENERAL PLANT VINTAGE GROUP (AMORTIZED) ACCOUNTS

FERC Account 303 Intangible Computer Software – 5 year (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with miscellaneous computer software. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show zero percent net salvage. Based on history and judgment, retention of zero percent net salvage for this account is recommended.

FERC Account 391 General Office Furniture & Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with miscellaneous office furniture such as desks, chairs, filing cabinets, and tables used for general utility service. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show negative 4.52 percent and negative 1.43 percent, respectively. Based on history and judgment, retention of zero percent net salvage for this account is recommended.

FERC Account 391 General Network Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with computer equipment used for general utility service. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving average shows zero percent net salvage for both periods. Based on history and judgment, retention of zero percent net salvage for this account is recommended.

FERC Account 392 General Transportation Equipment - Automobiles (proposed 5 percent net salvage)

This account consists of any gross salvage and cost of removal associated with automobiles used for general utility service. The approved net salvage for this account is zero percent. In the last depreciation study, the Company applied any gross salvage for transportation equipment to the new asset. That practice has been discontinued and all salvage proceeds are now being booked to the accumulated provision for depreciation. Based on recent retirement history, 5 percent net salvage for this account is recommended.

FERC Account 392 General Transportation Equipment - Light Trucks (proposed 10 percent net salvage)

This account consists of any gross salvage and cost of removal associated with light trucks used for general utility service. The approved net salvage for this account is zero percent. In the last depreciation study, the Company applied any gross salvage for transportation equipment to the new asset. That practice has been discontinued and all salvage proceeds are now being booked to the accumulated provision for depreciation. Based on recent retirement history, 10 percent net salvage for this account is recommended.

FERC Account 392 General Transportation Equipment - Trailers (proposed 20 percent net salvage)

This account consists of any gross salvage and cost of removal associated with trailers used for general utility service. The approved net salvage for this account is zero percent. In the last depreciation study, the Company applied any gross salvage for transportation equipment to the new asset. That practice has been discontinued and all salvage proceeds are now being booked to the accumulated provision for depreciation. Based on recent retirement history, 20 percent net salvage for this account is recommended.

FERC Account 392 General Transportation Equipment - Heavy Trucks (proposed 15 percent net salvage)

This account consists of any gross salvage and cost of removal associated with heavy trucks used for general utility service. The approved net salvage for this account is zero percent. In the last depreciation study, the Company applied any gross salvage for transportation equipment to the new asset. That practice has been discontinued and all salvage proceeds are now being booked to the accumulated provision for depreciation. Based on recent retirement history, 15 percent net salvage for this account is recommended.

FERC Account 393 General Stores Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with stores equipment used for general utility service. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show less than 1 percent net salvage for both periods. Based on history and judgment, retention of zero percent net salvage for this account is recommended.

FERC Account 394 General Tools, Shop & Garage Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with various items or tools used in shop and garages such as air compressors, grinders, mixers, hoists, and cranes. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show zero percent net salvage. Based on history and judgment, retention of zero percent net salvage for this account is recommended.

FERC Account 395 General Laboratory Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with laboratory equipment used in general utility service. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show zero percent net salvage. Based on history and judgment, retention of zero percent net salvage is recommended for this account.

FERC Account 396 General Power Operated Equipment (proposed 15 percent net salvage)

This account consists of any gross salvage and cost of removal associated with bulldozers, forklifts, trenchers, and other power operated equipment that cannot be licensed on roadways. The approved net salvage for this account is zero percent. In the last depreciation study, the Company applied any gross salvage for transportation equipment to the new asset. That practice has been discontinued and all salvage proceeds are now being booked to the accumulated provision for depreciation. Based on recent retirement history, 15 percent net salvage for this account is recommended.

FERC Account 397 General Communication Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with miscellaneous communication equipment used in general utility service. The approved net salvage for this account is zero percent. The most recent 5 and 10 year moving averages show negative 0.35 percent and negative 0.56 percent net salvage respectively. Following that trend, retention of zero percent net salvage for this account is recommended.

FERC Account 397 General Communication Equipment – Two Way (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with miscellaneous two way communication equipment used in general utility service. The approved net salvage for this account is zero percent. Based on experience with the other 397 accounts, retention of zero percent net salvage for this account is recommended.

FERC Account 397 General Communication Equipment – AES (proposed zero

percent net salvage)

This account consists of any gross salvage and cost of removal associated with miscellaneous AES including electronic or automated meter reading communication equipment used in general utility service. The approved net salvage for this account is zero percent. No data for this subaccount exists. Based on experience with the other 397 accounts, retention of zero percent net salvage for this account is recommended.

FERC Account 397 General Communication Equipment – EMS (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with EMS communication equipment used for energy monitoring and controlling equipment to manage general utility service. The approved net salvage for this account is zero percent. No data for this subaccount exists. Based on experience with the other 397 accounts and the characteristics of the assets in this account, retention of zero percent net salvage for this account is recommended.

FERC Account 398 General Miscellaneous Equipment (proposed zero percent net salvage)

This account consists of any gross salvage and cost of removal associated with miscellaneous equipment used in general utility service. The approved net salvage for this account is zero percent. There is minimal retirement experience in this account. The most recent 5 and 10 year moving averages show zero and negative 3.18 percent net salvage, respectively. Based on history and judgment, retention of zero percent net salvage for this account is recommended.

GAS DEPRECIATED PLANT

TRANSMISSION

Transmission Accounts, FERC Accounts 366 - 369

FERC Account 366 Transmission Structures & Improvements (proposed negative 5 percent net salvage)

This account includes any gross salvage and cost of removal associated with structures and improvements used in conjunction with transmission operations such as buildings, fences, or other structures. The approved net salvage for this account is negative 5 percent. There is limited retirement activity in this account. Based on history and judgment, retention of negative 5 percent net salvage for this account is recommended.

FERC Account 367 Transmission Mains (proposed negative 15 percent net salvage)

This account includes any gross salvage and cost of removal associated with the costs of transmission system mains including excavation costs, pipe, valves, and other equipment. The approved net salvage for this account is negative 15 percent. The most recent 5 and 10 year moving averages show negative 65.39 percent and negative 54.80 percent net salvage respectively. The high negative net salvage is driven by large removal cost in one year and is discounted. Based on history and judgment, retention of negative 15 percent net salvage for this account is recommended.

FERC Account 369 Transmission Measure & Regulating Station Equipment (proposed negative 30 percent net salvage)

This account includes any gross salvage and cost of removal associated with the costs of meters, gauges, and other equipment used to measure or regulate gas in connection with transmission city gate (town border station) operations. The approved net salvage for this account is negative 30 percent. The most recent 5 and 10 year moving averages show negative 75.01 percent and negative 58.19

percent net salvage respectively. Based on history and judgment, retention of negative 30 percent net salvage for this account is recommended.

DISTRIBUTION

Distribution Accounts, FERC Accounts 375 - 380

FERC Account 375 Distribution Structures & Improvements (proposed negative 5 percent net salvage)

This account any gross salvage and cost of removal associated with small structures and improvements to such structures and associated assets at city gates and on the main line distribution system. The approved net salvage for this account is zero percent. Data is limited for this account. The most recent 10 year moving averages shows negative 63.47 percent net salvage. Moving in the direction of that trend, negative 5 percent net salvage for this account is recommended.

FERC Account 376 Distribution Mains – Metallic (proposed negative 25 percent net salvage)

This account includes any gross salvage and cost of removal associated with all steel mains. The approved net salvage for this account is negative 20 percent. The most recent 5 and 10 year moving averages show negative 49.60 percent and negative 41.17 percent net salvage respectively. Moving in the direction of that trend, negative 25 percent net salvage for this account is recommended.

FERC Account 376 Distribution Mains – Plastic (proposed negative 20 percent net salvage)

This account includes any gross salvage and cost of removal associated with all plastic mains. The approved net salvage for this account is negative 15 percent. The most recent 5 and 10 year moving averages show negative 133.57 percent and negative 56.76 percent net salvage respectively. Moving in the direction of that trend, negative 20 percent net salvage for this account is recommended.

FERC Account 378 Distribution Measure & Regulating Station Equipment – General (proposed negative 25 percent net salvage)

This account consists of any gross salvage and cost of removal associated with meters, gauges, and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries city gate and to customers. The approved net salvage for this account is negative 25 percent. The most recent 5 and 10 year moving averages show negative 20.03 percent and negative 28.56 percent net salvage respectively. Retention of negative 25 percent net salvage for this account is recommended.

FERC Account 379 Distribution Measure & Regulating Station Equipment - City Gate (proposed negative 5 percent net salvage)

This account consists of any gross salvage and cost of removal associated with measuring and regulating devices and other apparatus at city gate stations. The approved net salvage for this account is negative 2 percent. The most recent 5 and 10 year moving averages show negative 73.36 percent and negative 71.54 percent net salvage respectively. There are few retirement in recent years in this account which would caution against a significant movement in net salvage. A negative 5 percent net salvage for this account is recommended.

FERC Account 380 Distribution Services - Metallic (proposed negative 40 percent net salvage)

Service lines are the steel pipes and accessories leading from the main to the customers' premises. The approved net salvage for this account is negative 40 percent. The most recent 5 and 10 year moving averages show negative 40.33 percent and negative 44.77 percent net salvage respectively. Moving in the direction of that trend, negative 40 percent net salvage for this account is recommended.

FERC Account 380 Distribution Services - Plastic (proposed negative 25 percent net salvage)

Service lines are the plastic pipes and accessories leading from the main to the customers' premises. The approved net salvage for this account is negative 30 percent. The most recent 5 and 10 year moving averages show negative 11.62 percent and negative 18.24 percent net salvage respectively. The decrease in 2016 is due to a large retirement in 2016. The 5 and 10 year bands from 2015 demonstrate a net salvage more negative than 25 percent. A negative 25 percent net salvage for this account is recommended.

<u>GENERAL</u>

General Accounts, FERC Accounts 390

FERC Account 390 General Structures & Improvements (proposed negative 14 percent net salvage)

This account includes any gross salvage and cost of removal associated with cost of general structures and improvements used for utility service. The approved net salvage for this account is negative 20 percent. There has been little retirement activity in this account. Based on data for Account 390 Electric and 390 Common, negative 14 percent net salvage for this account is recommended.

GAS VINTAGE GROUP (AMORTIZED) ACCOUNTS

GAS DISTRIBUTION

Account 381 Distribution Meters (proposed negative 5 percent net salvage)

This account includes any gross salvage and cost of removal associated with the cost of meters. The approved net salvage for this account is negative 3 percent. The most recent 5 and 10 year moving averages show negative 4.11 percent and negative 5.82 percent net salvage respectively. A negative 5 percent net salvage for this account is recommended.

Account 381 Distribution Meters - Telemetering (proposed zero percent net salvage)

This account includes any gross salvage and cost of removal associated with the cost of telemetering assets. The approved net salvage for this account is 0 percent. There has been limited retirement experience. Based on data and judgment, retention of zero percent net salvage for this account is recommended. This analysis is for any future investment in this account. The investment in this account is fully amortized in 2017.

Account 383 Distribution House Regulators (proposed negative 1 percent net salvage)

This account includes any gross salvage and cost of removal associated with cost of house regulators. The approved net salvage for this account is zero percent. The most recent 10 year moving average shows negative 1.25 percent net salvage. Based on recent history and judgment, negative 1 percent net salvage for this account is recommended.

GENERAL PLANT VINTAGE GROUP (AMORTIZED) ACCOUNTS

The same net salvage parameters used for electric plant are proposed for amortized gas plant due to the similar operations and policies. The table below summarizes recommendations by account.

GAS AMORTIZED ACCOUNTS

Acct	Description	Current Net Salvage	Proposed Net Salvage
Intangible			
303	Computer Software - 5 Year	0	0
303	Computer Software – 10 Year	0	0
General Plant			
391	Office Furniture & Equipment	0	0
391	Network Equipment	0	0
392	Transportation Equipment - Automobiles	0	5
392	Transportation Equipment - Light Trucks	0	10
392	Transportation Equipment - Trailers	0	20
392	Transportation Equipment - Heavy Trucks	0	15
393	Stores Equipment	0	0
394	Tools, Shop & Garage Equipment	0	0
395	Laboratory Equipment	0	0
396	Power Operated Equipment	0	15
397	Communication Equipment	0	0
397	Communication Equipment - AES	0	0
397	Communication Equipment - EMS	0	0
398	Miscellaneous Equipment	0	0

COMMON UTILITY PLANT DEPRECIATED ACCOUNTS

General Accounts, FERC Account 390

FERC Account 390 General Structures & Improvements (proposed negative 25 percent net salvage)

This account includes any gross salvage or cost of removal associated with the cost of general structures and improvements used for utility service. The approved net salvage for this account is negative 20 percent. Net salvage data shows negative net salvage in most bands. The most recent 5 and 10 year averages are negative 23.43 percent and negative 41.13 percent respectively. A negative 25 percent net salvage for this account is recommended.

FERC Account 390 General Structures & Improvements – Leased (proposed zero percent net salvage)

This account includes any gross salvage or cost of removal associated with the cost of leasehold improvements used for utility service. The approved net salvage for this account is zero percent. There has been no retirement experience in this account. These assets typically have no net salvage. Based on judgment, retaining zero percent net salvage for this account is recommended.

GENERAL PLANT VINTAGE GROUP (AMORTIZED) ACCOUNTS

The same net salvage parameters used for electric and gas plant are proposed for amortized common plant due to the similar operations and policies. The table below summarizes recommendations by account.

COMMON AMORTIZED PLANT

Acct	Description	Current Net Salvage	Proposed Net Salvage
Intangible			
303	Computer Software - 3 Year	0	0
303	Computer Software - 5 Year	0	0
303	Computer Software - 7 Year	0	0
303	Computer Software - 10 Year	0	0
303	Computer Software – 15 Year	0	0
General Plant			
391	Office Furniture & Equipment	0	0
391	Network Equipment	0	0
392	Transportation Equipment - Automobiles	0	5
392	Transportation Equipment - Light Trucks	0	10
392	Transportation Equipment - Trailers	0	20
392	Transportation Equipment - Heavy Trucks	0	15
393	Stores Equipment	0	0
394	Tools, Shop & Garage Equipment	0	0
395	Laboratory Equipment	0	0
396	Power Operated Equipment	0	15
397	Communication Equipment	0	0
397	Communication Equipment Two Way	0	0
398	Miscellaneous Equipment	0	0

APPENDIX A

Depreciation Rate Calculations

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
2017 Summary of Annual Depreciation Accruals
Average Service Life
Utility Accounts

FERC Account	Company Account	Account Description	Plant Balance 01/01/2017	Depreciation Reserve 01/01/2017	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unaccrued Balance	Remaining Life (Yrs)	Annual Accrual	Depr Rate	Reserve Ratio
Electric Utility											
Transmission											
352	10352000	Structures & Improvements	103,086,366	16,791,010	-5%	(5,154,318)	91,449,675	58.75	1,556,629	1.51%	16.29%
353	10353000	Station Equipment	1,181,449,210	266,220,136	-15%	(177,217,381)	1,092,446,456	44.63	24,478,696	2.07%	22.53%
354	10354000	Towers & Fixtures	118,631,858	66,493,064	-35%	(41,521,150)	93,659,945	42.73	2,191,928	1.85%	56.05%
355	10355000	Poles & Fixtures	1,330,556,061	188,365,602	-50%	(665,278,031)	1,807,468,490	55.94	32,313,257	2.43%	14.16%
356	10356000	Overhead Conductor & Devices	532,704,102	89,241,054	-35%	(186,446,436)	629,909,483	58.38	10,789,141	2.03%	16.75%
357	10357000	Underground Conduit	25,910,138	3,722,204	0%	-	22,187,934	62.13	357,111	1.38%	14.37%
358	10358000	Underground Conductor & Devices	30,710,573	6,723,959	-5%	(1,535,529)	25,522,143	39.20	651,157	2.12%	21.89%
		Total Transmission	3,323,048,309	637,557,028		(1,077,152,845)	3,762,644,126		72,337,918		
Distribution - Minnesota Only											
361	10361000	Structures & Improvements	43,721,596	14,082,032	-30%	(13,116,479)	42,756,043	47.26	904,773	2.07%	32.21%
362	10362000	Station Equipment	552,978,032	194,058,095	-25%	(138,244,508)	497,164,446	37.99	13,086,190	2.37%	35.09%
364	10364000	Poles, Towers & Fixtures	343,536,905	194,086,158	-120%	(412,244,286)	561,695,032	34.83	16,128,736	4.69%	56.50%
365	10365000	Overhead Conductor & Devices	373,235,852	101,963,938	-25%	(93,308,963)	364,580,877	30.40	11,991,745	3.21%	27.32%
366	10366000	Underground Conduit	261,312,548	77,065,329	-20%	(52,262,510)	236,509,728	42.12	5,615,408	2.15%	29.49%
367	10367000	Underground Conductor & Devices	967,850,933	266,729,577	-10%	(96,785,093)	797,906,449	36.62	21,790,377	2.25%	27.56%
369	10369010	Services - Overhead	71,641,753	53,940,897	-85%	(60,895,490)	78,596,346	24.76	3,174,525	4.43%	75.29%
369	10369020	Services - Underground	185,773,119	83,201,886	-5%	(9,288,656)	111,859,888	25.07	4,461,977	2.40%	44.79%
373	10373000	Street Lighting & Signal Systems	64,184,329	20,920,586	-40%	(25,673,732)	68,937,475	22.19	3,106,722	4.84%	32.59%
		Total Distribution	2,864,235,067	1,006,048,499		(901,819,716)	2,760,006,284		80,260,452		
General											
390	10390000	Structures & Improvements	63,508,306	23,807,986	-20%	(12,701,661)	52,401,982	36.29	1,444,043	2.27%	37.49%
390	10390007	Leasehold Improvements*	35,652	35,652	0%	-	-	0.00	-	0.00%	100.00%
		Total General	63,543,958	23,843,637		(12,701,661)	52,401,982		1,444,043		
		Total Electric Utility	6,250,827,334	1,667,449,165		(1,991,674,222)	6,575,052,391		154,042,413		

* Rate if plant added to group

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
2017 Summary of Annual Depreciation Accruals
Average Service Life
Utility Accounts

FERC Account	Company Account	Account Description	Plant Balance 01/01/2017	Depreciation Reserve 01/01/2017	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unaccrued Balance	Remaining Life (Yrs)	Annual Accrual	Depr Rate	Reserve Ratio
Gas Utility											
Transmission											
366	20366000	Structures & Improvements	1,130,639	631,260	-5%	(56,532)	555,910	42.90	12,958	1.15%	55.83%
367	20367000	Mains	65,790,678	23,607,633	-15%	(9,868,602)	52,051,647	60.44	861,239	1.31%	35.88%
369	20369000	Measure & Regulating Station Equipment	13,617,811	6,322,674	-30%	(4,085,343)	11,380,481	31.13	365,544	2.68%	46.43%
		Total Transmission	80,539,128	30,561,568		(14,010,477)	63,988,038		1,239,741		
Distribution - Minnesota Only											
375	20375000	Structures & Improvements	727,864	78,795	-5%	(36,393)	685,462	45.78	14,973	2.06%	10.83%
376	20376010	Mains - Metallic	135,069,020	47,649,540	-25%	(33,767,255)	121,186,735	48.59	2,493,923	1.85%	35.28%
376	20376020	Mains - Plastic	384,394,656	138,702,955	-20%	(76,878,931)	322,570,631	40.84	7,897,877	2.05%	36.08%
378	20378000	Measure & Regulating Station Equipment - General	22,768,672	4,523,719	-25%	(5,692,168)	23,937,121	33.10	723,205	3.18%	19.87%
379	20379000	Measure & Regulating Station Equipment - City Gate	1,392,566	303,648	-5%	(69,628)	1,158,546	31.61	36,656	2.63%	21.80%
380	20380010	Services - Metallic	12,590,915	11,375,605	-40%	(5,036,366)	6,251,676	24.13	259,080	2.06%	90.35%
380	20380020	Services - Plastic	272,681,597	142,142,133	-25%	(68,170,399)	198,709,863	25.82	7,695,540	2.82%	52.13%
		Total Distribution	829,625,290	344,776,397		(189,651,141)	674,500,034		19,121,255		
General											
390	20390000	Structures & Improvements	1,493,079	70,882	-14%	(209,031)	1,631,228	46.31	35,226	2.36%	4.75%
		Total General	1,493,079	70,882		(209,031)	1,631,228		35,226		
		Total Gas Utility	911,657,497	375,408,846		(203,870,649)	740,119,300		20,396,222		

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
2017 Summary of Annual Depreciation Accruals
Average Service Life
Utility Accounts

FERC Account	Company Account	Account Description	Plant Balance 01/01/2017	Depreciation Reserve 01/01/2017	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unaccrued Balance	Remaining Life (Yrs)	Annual Accrual	Depr Rate	Reserve Ratio
Common Utility											
General											
390	40390000	Structures & Improvements	151,813,406	21,297,336	-25%	(37,953,352)	168,469,422	42.93	3,923,825	2.58%	14.03%
390	40390007	Structures & Improvements - Leased	18,509,449	1,409,381	0%	-	17,100,068	9.04	1,891,324	10.22%	7.61%
		Total General	170,322,855	22,706,717		(37,953,352)	185,569,490		5,815,149		
		Total Common Utility	170,322,855	22,706,717		(37,953,352)	185,569,490		5,815,149		
		Total ASL- All Utilities	7,332,807,686	2,065,564,727		(2,233,498,223)	7,500,741,181		180,253,784		

Xcel Energy
Computation of Amortization Rate
Vintage Group
Electric Utility

FERC Account	Company Account	Account Description	Plant Balance 01/01/2017	Depreciation Reserve 01/01/2017	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unaccrued Balance	Remaining Life (Yrs)	Annual Accrual	Depr Rate	Reserve Ratio
Distribution - Minnesota Only											
368	10368000	Line Transformers	372,629,100	171,239,942	-5%	(18,631,455)	220,020,612	18.27	12,045,571	3.23%	45.95%
368	10368010	Line Capacitors	15,188,563	8,150,381	-7%	(1,063,199)	8,101,381	12.71	637,473	4.20%	53.66%
370	10370000	Meters	54,362,948	24,702,877	-5%	(2,718,147)	32,378,218	8.64	3,749,220	6.90%	45.44%
		Total Electric Vintage Group	442,180,610	204,093,201		(22,412,802)	260,500,211		16,432,264		

Note: Electric Amortized Accounts exclude known change retirements which will occur when the age of the asset is greater than average service life.

Xcel Energy
Computation of Amortization Rate
Vintage Group
Gas Utility

FERC Account	Company Account	Account Description	Plant Balance 01/01/2017	Depreciation Reserve 01/01/2017	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unaccrued Balance	Remaining Life (Yrs)	Annual Accrual	Depr Rate	Reserve Ratio
Distribution- Minnesota Only											
381	20381000	Meters	92,178,273	57,890,884	-5%	(4,608,914)	38,896,303	9.76	3,986,321	4.32%	62.80%
381	20381010	Meters - Telemetering	-	-	0%	-	-	NA	-	NA	NA
383	20383000	House Regulators	10,070,258	10,170,961	-1%	(100,703)	0	2.00	0	0.00%	101.00%
		Total Gas Vintage Group	102,248,532	68,061,845		(4,709,616)	38,896,303		3,986,321		

Note: Gas Amortized Accounts exclude known change retirements which will occur when the age of the asset is greater than average service life.

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Computation of Amortization Amount
For Amortized Property
At January 1, 2017
Electric Utility

FERC Account	Description	Plant Balance 01/01/2017	Allocated Reserve 01/01/2017	Theoretical Reserve 01/01/2017	Reserve Difference	Remaining Life	Amortize Reserve Difference
Intangible							
303	Intangible Computer Software - 5 Year	115,172,555	72,443,511	77,704,767	(5,261,257)	2.14	2,453,471
	Total Intangible	115,172,555	72,443,511	77,704,767	(5,261,257)		2,453,471
General							
391	Office Furniture & Equipment	27,593,861	14,947,880	13,486,891	1,460,989	10.22	(142,888)
391	Network Equipment	32,398,061	11,957,884	10,809,106	1,148,778	4.00	(287,324)
392	Transportation Equipment - Automobiles	1,108,813	391,080	352,850	38,230	6.65	(5,749)
392	Transportation Equipment - Light Trucks	32,832,470	19,387,112	18,141,619	1,245,493	5.03	(247,756)
392	Transportation Equipment - Trailers	17,878,078	5,631,534	5,107,733	523,801	7.71	(67,898)
392	Transportation Equipment - Heavy Trucks	97,589,361	37,083,215	33,922,126	3,161,090	7.50	(421,554)
393	Stores Equipment	1,648,791	790,289	715,144	75,145	11.33	(6,635)
394	Tools, Shop & Garage Equipment	81,301,137	33,694,832	30,556,536	3,138,296	9.38	(334,430)
395	Laboratory Equipment	3,209,733	1,630,248	1,487,920	142,328	5.36	(26,532)
396	Power Operated Equipment	45,134,817	15,825,286	14,318,885	1,506,401	7.52	(200,287)
397	Communication Equipment	17,117,461	11,636,242	10,799,860	836,381	3.73	(224,517)
397	Communication Equipment - Two Way	6,532,362	669,209	603,791	65,418	9.08	(7,208)
397	Communication Equipment - AES	7,071,726	3,976,600	3,587,868	388,732	7.39	(52,605)
397	Communication Equipment - EMS	47,275,858	8,169,456	7,370,853	798,604	12.66	(63,074)
398	Miscellaneous Equipment	2,723,841	2,211,897	2,004,226	207,671	4.06	(51,122)
	Total General	421,416,370	168,002,764	153,265,408	14,737,356		(2,139,579)
	Total Electric Intangible and General	536,588,924	240,446,274	230,970,175	9,476,099		313,892

Excluding Fully Accrued Assets

FERC Account	Description	Plant Balance 01/01/2017	Allocated Reserve 01/01/2017	Amortization Life	Net Salvage %	Annual Amortization	Accrual For Reserve Difference	Total Amortization	Amortization Rate
Intangible									
303	Intangible Computer Software - 5 Year	87,361,384	44,632,341	5.00	0.00%	17,472,277	2,453,471	19,925,748	22.81%
	Total Intangible	87,361,384	44,632,341			17,472,277	2,453,471	19,925,748	
General									
391	Office Furniture & Equipment	27,593,861	14,947,880	20.00	0.00%	1,379,693	(142,888)	1,236,805	4.48%
391	Network Equipment	32,398,061	11,957,884	6.00	0.00%	5,399,677	(287,324)	5,112,352	15.78%
392	Transportation Equipment - Automobiles	1,108,813	391,080	10.00	5.00%	105,337	(5,749)	99,589	8.98%
392	Transportation Equipment - Light Trucks	26,592,763	13,147,406	10.00	10.00%	2,393,349	(247,756)	2,145,592	8.07%
392	Transportation Equipment - Trailers	17,878,078	5,631,534	12.00	20.00%	1,191,872	(67,898)	1,123,974	6.29%
392	Transportation Equipment - Heavy Trucks	93,469,576	32,963,431	12.00	15.00%	6,620,762	(421,554)	6,199,207	6.63%
393	Stores Equipment	1,648,791	790,289	20.00	0.00%	82,440	(6,635)	75,804	4.60%
394	Tools, Shop & Garage Equipment	81,113,250	33,506,944	15.00	0.00%	5,407,550	(334,430)	5,073,120	6.25%
395	Laboratory Equipment	3,209,733	1,630,248	10.00	0.00%	320,973	(26,532)	294,441	9.17%
396	Power Operated Equipment	45,134,817	15,825,286	12.00	15.00%	3,197,050	(200,287)	2,996,763	6.64%
397	Communication Equipment	16,958,859	11,477,639	10.00	0.00%	1,695,886	(224,517)	1,471,369	8.68%
397	Communication Equipment - Two Way	6,532,362	669,209	10.00	0.00%	653,236	(7,208)	646,028	9.89%
397	Communication Equipment - AES	7,071,726	3,976,600	15.00	0.00%	471,448	(52,605)	418,844	5.92%
397	Communication Equipment - EMS	47,275,858	8,169,456	15.00	0.00%	3,151,724	(63,074)	3,088,650	6.53%
398	Miscellaneous Equipment	2,657,198	2,145,253	15.00	0.00%	177,147	(51,122)	126,025	4.74%
	Total General	410,643,745	157,230,139			32,248,143	(2,139,579)	30,108,564	
	Total Electric Intangible & General	498,005,130	201,862,480			49,720,419	313,892	50,034,312	

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Gas Utility

FERC Account	Description	Plant Balance 01/01/2017	Allocated Reserve 01/01/2017	Theoretical Reserve 01/01/2017	Reserve Difference	Remaining Life	Amortize Reserve Difference
Intangible							
303	Intangible Computer Software - 10 Year	7,256,644	5,122,739	5,090,801	31,937.94	2.58	(12,369)
303	Intangible Computer Software - 5 Year	234,274	85,975	81,996	3,978.61	6.50	(612)
	Total Intangible	7,490,919	5,208,713	5,172,797	35,917		(12,981)
General							
391	Office Furniture & Equipment	906,378	467,586	299,696	167,890	13.39	(12,541)
391	Network Equipment	38,023	25,279	15,843	9,436	3.50	(2,696)
392	Transportation Equipment - Automobiles	376,943	67,568	42,346	25,222	8.82	(2,860)
392	Transportation Equipment - Light Trucks	6,054,537	3,889,243	2,961,227	928,016	5.49	(169,051)
392	Transportation Equipment - Trailers	1,504,110	753,603	550,626	202,977	6.84	(29,686)
392	Transportation Equipment - Heavy Trucks	8,425,887	5,125,059	3,787,150	1,337,909	6.39	(209,494)
393	Stores Equipment	10,091	4,428	2,775	1,653	14.50	(114)
394	Tools, Shop & Garage Equipment	6,257,777	2,797,083	1,878,476	918,606	10.40	(88,335)
396	Power Operated Equipment	2,858,219	946,052	622,370	323,682	8.93	(36,263)
397	Communication Equipment	4,722,283	4,554,658	3,635,958	918,700	2.30	(399,361)
397	Communication Equipment - Two Way	120,072	15,970	10,009	5,961	9.17	(650)
397	Communication Equipment - AES	15,492,768	6,555,265	4,108,288	2,446,977	11.02	(222,001)
397	Communication Equipment - EMS	764,413	356,090	223,167	132,923	10.62	(12,515)
398	Miscellaneous Equipment	50,705	42,589	33,509	9,080	5.09	(1,785)
	Total General	47,582,206	25,600,471	18,171,440	7,429,031		(1,187,353)
	Total Gas Intangible & General	55,073,125	30,809,184	23,344,237	7,464,947		(1,200,334)

Excluding Fully Accrued Assets

FERC Account	Description	Plant Balance 01/01/2017	Allocated Reserve 01/01/2017	Amortization Life	Net Salvage %	Annual Amortization	Accrual For Reserve Difference	Total Amortization	Amortization Rate
Intangible									
303	Intangible Computer Software - 5 Year	4,194,027	2,060,121	5	0	838,805	(12,369)	826,436	19.71%
303	Intangible Computer Software - 10 Year	234,274	81,996	10	0	23,427	(612)	22,815	9.74%
	Total Intangible	4,428,301	2,142,117			862,233	(12,981)	849,251	
General									
391	Office Furniture & Equipment	906,378	468,787	20	0.00%	45,319	(12,541)	32,778	3.62%
391	Network Equipment	38,023	25,348	6	0.00%	6,337	(2,696)	3,641	9.58%
392	Transportation Equipment - Automobiles	376,943	67,753	10	5.00%	35,810	(2,860)	32,949	8.74%
392	Transportation Equipment - Light Trucks	5,207,054	3,044,907	10	10.00%	468,635	(169,051)	299,584	5.75%
392	Transportation Equipment - Trailers	1,453,858	704,544	12	20.00%	96,924	(29,686)	67,238	4.62%
392	Transportation Equipment - Heavy Trucks	7,700,813	4,406,250	12	15.00%	545,474	(209,494)	335,981	4.36%
393	Stores Equipment	10,091	4,440	20	0.00%	505	(114)	391	3.87%
394	Tools, Shop & Garage Equipment	6,316,850	2,861,461	15	0.00%	421,123	(88,335)	332,788	5.27%
396	Power Operated Equipment	2,858,219	947,870	12	15.00%	202,457	(36,263)	166,194	5.81%
397	Communication Equipment	4,722,283	4,556,223	10	0.00%	472,228	(399,361)	72,867	1.54%
397	Communication Equipment - Two Way	120,072	16,014	10	0.00%	12,007	(650)	11,357	9.46%
397	Communication Equipment - AES	15,492,768	6,573,194	15	0.00%	1,032,851	(222,001)	810,850	5.23%
397	Communication Equipment - EMS	764,413	357,064	15	0.00%	50,961	(12,515)	38,446	5.03%
398	Miscellaneous Equipment	50,705	2,878	15	0.00%	3,380	(1,785)	1,596	3.15%
	Total General	46,018,470	24,036,734			3,394,012	(1,187,353)	2,206,659	
	Total Gas Intangible & General	50,446,771	26,178,851			4,256,244	(1,200,334)	3,055,910	

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Common Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Allocated Reserve 01/01/2017	Theoretical Reserve 01/01/2017	Reserve Difference	Remaining Life	Amortize Reserve Difference
Intangible							
303	Intangible Computer Software - 3 Year	7,673,530	7,673,530	7,673,530	0	0.00	0
303	Intangible Computer Software - 5 Year	197,541,349	133,587,921	137,960,011	(4,372,090)	2.70	1,617,774
303	Intangible Computer Software - 7 Year	44,140,612	44,140,612	44,140,612	0	0.00	0
303	Intangible Computer Software - 10 Year	68,449,240	61,860,387	62,199,795	(339,408)	6.14	55,296
303	Intangible Computer Software - 15 Year	61,015,418	3,523,252	3,856,103	(332,851)	14.05	23,687
	Total Intangible	378,820,150	250,785,703	255,830,052	(5,044,349)		1,696,756
General							
391	Office Furniture & Equipment	27,141,560	15,321,726	14,505,093	816,633	10.44	(78,237)
391	Network Equipment	100,446,164	46,842,989	43,560,690	3,282,299	2.83	(1,159,189)
392	Transportation Equipment - Automobiles	823,465	290,391	270,044	20,346	6.55	(3,107)
392	Transportation Equipment - Light Trucks	3,431,469	1,949,727	1,924,358	25,369	3.81	(6,667)
392	Transportation Equipment - Trailers	1,099,687	661,080	622,073	39,008	4.20	(9,292)
392	Transportation Equipment - Heavy Trucks	5,505,442	3,756,624	3,612,498	144,126	4.17	(34,598)
393	Stores Equipment	246,162	44,140	41,047	3,093	16.67	(186)
394	Tools, Shop & Garage Equipment	4,041,708	1,492,666	1,389,262	103,404	9.87	(10,476)
395	Laboratory Equipment	0	0	0	0	0.00	0
396	Power Operated Equipment	990,912	565,370	545,459	19,912	6.74	(2,953)
397	Communication Equipment	964,432	831,102	790,286	40,815	2.43	(16,778)
397	Communication Equipment - Two Way	75,068	4,036	3,753	283	9.50	(30)
398	Miscellaneous Equipment	582,227	420,760	400,574	20,186	4.68	(4,313)
	Total General	145,348,298	72,180,609	67,665,137	4,515,473		(1,325,825)
	Total Common Intangible & General	524,168,448	322,966,313	323,495,189	(528,876)		370,931

Common Utility

Excluding Fully Accrued Assets

FERC Account	Description	Plant Balance 01/01/2017	Allocated Reserve 01/01/2017	Amortization Life	Net Salvage %	Annual Amortization	Accrual For Reserve Difference	Total Amortization	Amortization Rate	
Intangible										
303	Intangible Computer Software - 3 Year	0	0	3.00	0.00%	0	0	0	33.33%	(2)
303	Intangible Computer Software - 5 Year	110,232,298	46,278,871	5.00	0.00%	22,046,460	1,617,774	23,664,233	21.47%	
303	Intangible Computer Software - 7 Year	0	0	7.00	0.00%	0	0	0	14.29%	(2)
303	Intangible Computer Software - 10 Year	10,181,505	3,592,653	10.00	0.00%	1,018,150	55,296	1,073,446	10.54%	
303	Intangible Computer Software - 15 Year	61,015,418	3,523,252	15.00	0.00%	4,067,695	23,687	4,091,382	6.71%	
	Total Intangible	181,429,222	53,394,775			27,132,305	1,696,756	28,829,061		
(2) Rate if new plant is added										
General										
391	Office Furniture & Equipment	24,212,478	12,392,643	20	0.00%	1,210,624	(78,237)	1,132,387	4.68%	
391	Network Equipment	100,449,425	46,846,249	5	0.00%	20,089,885	(1,159,189)	18,930,696	18.85%	
392	Transportation Equipment - Automobiles	823,465	290,391	10	5.00%	78,229	(3,107)	75,122	9.12%	
392	Transportation Equipment - Light Trucks	3,406,217	1,924,475	10	10.00%	306,560	(6,667)	299,892	8.80%	
392	Transportation Equipment - Trailers	995,338	556,732	12	20.00%	66,356	(9,292)	57,063	5.73%	
392	Transportation Equipment - Heavy Trucks	4,253,089	2,504,271	12	15.00%	301,260	(34,598)	266,663	6.27%	
393	Stores Equipment	246,162	44,140	20	0.00%	12,308	(186)	12,123	4.92%	
394	Tools, Shop & Garage Equipment	4,030,816	1,481,774	15	0.00%	268,721	(10,476)	258,245	6.41%	
395	Laboratory Equipment	0	0	10	0.00%	0	0	0	10.00%	
396	Power Operated Equipment	709,729	284,187	12	15.00%	50,272	(2,953)	47,320	6.67%	
397	Communication Equipment	715,864	582,533	10	0.00%	71,586	(16,778)	54,808	7.66%	
397	Communication Equipment - Two Way	75,068	4,036	10	0.00%	7,507	(30)	7,477	9.96%	
398	Miscellaneous Equipment	582,227	420,760	15	0.00%	38,815	(4,313)	34,502	5.93%	
	Total General	140,499,879	67,332,190			22,502,124	(1,325,825)	21,176,299		
	Total Common Intangible & General	321,929,101	120,726,966			49,634,429	370,931	50,005,360		

APPENDIX B

Depreciation Expense Comparison

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Accruals
Average Service Life
Electric Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
Transmission									
352	Structures & Improvements	103,086,366		103,086,366	1.47	1,515,976	1.51%	1,556,604	40,628
353	Station Equipment	1,181,449,210		1,181,449,210	1.96	23,207,038	2.07%	24,455,999	1,248,961
354	Towers & Fixtures	118,631,858		118,631,858	1.93	2,287,900	1.85%	2,194,689	(93,211)
355	Poles & Fixtures	1,330,556,061		1,330,556,061	2.18	28,971,785	2.43%	32,332,512	3,360,727
356	Overhead Conductor & Devices	532,704,102		532,704,102	2.06	10,992,307	2.03%	10,813,893	(178,414)
357	Underground Conduit	25,910,138		25,910,138	1.37	354,933	1.38%	357,560	2,627
358	Underground Conductor & Devices	30,710,573		30,710,573	1.82	558,374	2.12%	651,064	92,690
	Total Transmission	3,323,048,309		3,323,048,309		67,888,314		72,362,322	4,474,008
Distribution - Minnesota Only									
361	Structures & Improvements	43,721,596		43,721,596	2.17	947,301	2.07%	905,037	(42,264)
362	Station Equipment	552,978,032		552,978,032	2.18	12,064,975	2.37%	13,105,579	1,040,604
364	Poles, Towers & Fixtures	343,536,905		343,536,905	4.55	15,615,314	4.69%	16,111,881	496,567
365	Overhead Conductor & Devices	373,235,852		373,235,852	3.08	11,484,180	3.21%	11,980,871	496,691
366	Underground Conduit	261,312,548		261,312,548	2.12	5,527,765	2.15%	5,618,220	90,454
367	Underground Conductor & Devices	967,850,933		967,850,933	2.22	21,507,799	2.25%	21,776,646	268,847
369	Services - Overhead	71,641,753		71,641,753	4.25	3,044,774	4.43%	3,173,730	128,955
369	Services - Underground	185,773,119		185,773,119	2.56	4,757,604	2.40%	4,458,555	(299,049)
373	Street Lighting & Signal Systems	64,184,329		64,184,329	4.66	2,987,891	4.84%	3,106,522	118,630
	Total Distribution	2,864,235,067		2,864,235,067		77,937,604		80,237,040	2,299,436
General									
390	Structures & Improvements	63,508,306		63,508,306	2.11	1,337,017	2.27%	1,441,639	104,622
390	Leasehold Improvements	35,652		35,652	10.00	3,565	10.00%	3,565	-
	Total General	63,543,958		63,543,958		1,340,582		1,445,204	104,622
	Total Electric Utility	6,250,827,334		6,250,827,334		147,166,500		154,044,565	6,878,065

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Accruals
Average Service Life
Gas Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
Transmission									
366	Structures & Improvements	1,130,639		1,130,639	2.02	22,830	1.15%	13,002	(9,828)
367	Mains	65,790,678		65,790,678	1.53	1,008,790	1.31%	861,858	(146,933)
369	Measure & Regulating Station Equipment	13,617,811		13,617,811	3.94	536,459	2.68%	364,957	(171,502)
	Total Transmission	80,539,128		80,539,128		1,568,080		1,239,818	(328,262)
Distribution - Minnesota Only									
375	Structures & Improvements	727,864		727,864	2.44	17,753	2.06%	14,994	(2,759)
376	Mains - Metallic	135,069,020		135,069,020	2.35	3,178,095	1.85%	2,498,777	(679,318)
376	Mains - Plastic	384,394,656		384,394,656	2.56	9,823,419	2.05%	7,880,090	(1,943,329)
378	Measure & Regulating Station Equipment - General	22,768,672		22,768,672	3.29	748,969	3.18%	724,044	(24,926)
379	Measure & Regulating Station Equipment - City Gate	1,392,566		1,392,566	2.68	37,379	2.63%	36,624	(755)
380	Services - Metallic	12,590,915		12,590,915	3.50	440,682	2.06%	259,373	(181,309)
380	Services - Plastic	272,681,597		272,681,597	3.33	9,089,387	2.82%	7,689,621	(1,399,766)
	Total Distribution	829,625,290		829,625,290		23,335,684		19,103,523	(4,232,160)
General									
390	Structures & Improvements	1,493,079		1,493,079	2.18	32,576	2.36%	35,237	2,660
	Total General	1,493,079		1,493,079		32,576		35,237	2,660
	Total Gas Utility	911,657,497		911,657,497		24,936,340		20,378,578	(4,557,762)

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Accruals
Average Service Life
Common Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
General									
390	Structures & Improvements	151,813,406		151,813,406	2.18	3,312,292	2.58%	3,916,786	604,493
390	Structures & Improvements - Leased	18,509,449		18,509,449	10.00	1,850,945	10.22%	1,891,666	40,721
	Total General	170,322,855		170,322,855		5,163,237		5,808,452	645,214
	Total Common Utility	170,322,855		170,322,855		5,163,237		5,808,452	645,214
	Total ASL All Utilities	7,332,807,686		7,332,807,686		177,266,077		180,231,595	2,965,517

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Accruals
Vintage Group
Electric Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
Intangible									
303	Intangible Computer Software - 5 Year	115,172,555	27,811,170	87,361,385	20.00	17,472,277	22.81%	19,927,132	2,454,855
	Total Intangible	115,172,555	27,811,170	87,361,385		17,472,277		19,927,132	2,454,855
General									
391	Office Furniture & Equipment	27,593,861	-	27,593,861	5.00	1,379,693	4.48%	1,236,205	(143,488)
391	Network Equipment	32,398,061	-	32,398,061	25.00	8,099,515	15.78%	5,112,414	(2,987,101)
392	Transportation Equipment - Automobiles	1,108,813	-	1,108,813	10.00	110,881	8.98%	99,571	(11,310)
392	Transportation Equipment - Light Trucks	32,832,470	6,239,706	26,592,763	8.33	2,216,064	8.07%	2,146,036	(70,028)
392	Transportation Equipment - Trailers	17,878,078	-	17,878,078	6.67	1,191,872	6.29%	1,124,531	(67,341)
392	Transportation Equipment - Heavy Trucks	97,589,361	4,119,785	93,469,576	7.14	6,676,398	6.63%	6,197,033	(479,365)
393	Stores Equipment	1,648,791	-	1,648,791	5.00	82,440	4.60%	75,844	(6,595)
394	Tools, Shop & Garage Equipment	81,301,137	187,888	81,113,250	6.67	5,407,550	6.25%	5,069,578	(337,972)
395	Laboratory Equipment	3,209,733	-	3,209,733	10.00	320,973	9.17%	294,333	(26,641)
396	Power Operated Equipment	45,134,817	-	45,134,817	8.33	3,761,235	6.64%	2,996,952	(764,283)
397	Communication Equipment	17,117,461.30	158,602	16,958,859	11.11	1,884,318	8.68%	1,472,029	(412,289)
		6,532,362.47	-	6,532,362	11.11	725,818	9.89%	646,051	(79,767)
397	Communication Equipment - AES	7,071,725.74	-	7,071,726	6.67	471,448	5.92%	418,646	(52,802)
397	Communication Equipment - EMS	47,275,857.53	-	47,275,858	6.67	3,151,724	6.53%	3,087,113	(64,610)
398	Miscellaneous Equipment	2,723,841	66,643	2,657,198	6.67	177,147	4.74%	125,951	(51,195)
	Total General	421,416,370	10,772,624	410,643,745		35,657,075		30,102,288	(5,554,788)
Distribution - Minnesota Only (Vintage Group Treatment)		Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017					
368	Line Transformers	372,629,100	0.00	372,629,100	3.28	12,226,892	3.23%	12,035,920	(190,972)
368	Line Capacitors	18,759,258	3,570,694.95	15,188,563	4.40	668,297	4.20%	637,920	(30,377)
370	Meters	96,316,591	41,953,643	54,362,948	6.67	3,624,197	6.90%	3,751,043	126,847
	Total Distribution	487,704,949	45,524,338	442,180,610		16,519,386		16,424,883	(94,503)
	Total Electric Utility	1,024,293,873	84,108,133	940,185,740		69,648,738		66,454,302	(3,194,435)

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Accruals
Vintage Group
Gas Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
Intangible									
303	Intangible Computer Software - 5 Year	7,256,644	3,062,618	4,194,027	20.00	838,805	19.71%	826,643	(12,163)
303	Intangible Computer Software - 10 Year	234,274	-	234,274	10.00	23,427	9.74%	22,818	(609)
	Total Intangible	7,490,919	3,062,618	4,428,301		862,233		849,461	(12,772)
General									
391	Office Furniture & Equipment	906,378	-	906,378	5.00	45,319	3.62%	32,811	(12,508)
391	Network Equipment	38,023	-	38,023	25.00	9,506	9.58%	3,643	(5,863)
392	Transportation Equipment - Automobiles	376,943	-	376,943	10.00	37,694	8.74%	32,945	(4,749)
392	Transportation Equipment - Light Trucks	6,054,537	847,483	5,207,054	8.33	433,921	5.75%	299,406	(134,516)
392	Transportation Equipment - Trailers	1,504,110	50,252	1,453,858	6.67	96,924	4.62%	67,168	(29,756)
392	Transportation Equipment - Heavy Trucks	8,425,887	725,075	7,700,813	7.14	550,058	4.36%	335,755	(214,303)
393	Stores Equipment	10,091	-	10,091	5.00	505	3.87%	391	(114)
394	Tools, Shop & Garage Equipment	6,257,777	(59,073)	6,316,850	6.67	421,123	5.27%	332,898	(88,225)
396	Laboratory Equipment	2,858,219	-	2,858,219	8.33	238,185	5.81%	166,062	(72,122)
397	Communication Equipment	4,722,283	-	4,722,283	11.11	524,698	1.54%	72,723	(451,975)
397	Communication Equipment - Two Way	120,072	-	120,072	11.11	13,341	9.46%	11,359	(1,983)
397	Communication Equipment - AES	15,492,768	-	15,492,768	6.67	1,032,851	5.23%	810,272	(222,579)
397	Communication Equipment - EMS	764,413	-	764,413	6.67	50,961	5.03%	38,450	(12,511)
398	Miscellaneous Equipment	50,705	-	50,705	6.67	3,380	3.15%	1,597	(1,783)
	Total General	47,582,206	1,563,737	46,018,470		3,458,467		2,205,480	(1,252,987)

		Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
Distribution - Minnesota Only (Vintage Group Treatment)									
381	Meters	105,068,640	12,890,367	92,178,273	5.15	4,747,181	4.32%	3,982,101	(765,080)
381	Meters - Telemetering	36,778	36,778	-	12.50	-	12.50%	-	-
383	House Regulators	10,070,258	-	10,070,258	5.00	-	0.00%	-	-
	Total Distribution	115,175,677	12,927,145	102,248,532		4,747,181		3,982,101	(765,080)
	Total Gas Utility	170,248,802	17,553,499	152,695,302		9,067,880		7,037,042	(2,030,839)

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Accruals
Vintage Group
Common Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Adjusted Plant Balance 01/01/2017	Present Annual Rate	Present Annual Accrual	Proposed Annual Rate	Proposed Annual Accrual	Proposed Less Present Accrual
Intangible									
303	Intangible Computer Software - 3 Year	7,673,530	7,673,530	-	33.33	-	33.33%	-	-
303	Intangible Computer Software - 5 Year	197,541,349	87,309,050	110,232,298	20.00	22,046,460	21.47%	23,666,874	1,620,415
303	Intangible Computer Software - 7 Year	44,140,612	44,140,612	-	14.29	-	14.29%	-	-
303	Intangible Computer Software - 10 Year	68,449,240	58,267,735	10,181,505	10.00	1,018,150	10.54%	1,073,131	54,980
303	Intangible Computer Software - 15 Year	61,015,418		61,015,418	6.67	4,067,695	6.71%	4,094,135	26,440
	Total Intangible	378,820,150	197,390,928	181,429,222		27,132,305		28,834,140	1,701,835
General									
391	Office Furniture & Equipment	27,141,560	2,929,083	24,212,478	5.00	1,210,624	4.68%	1,133,144	(77,480)
391	Network Equipment	100,446,164	(3,261)	100,449,425	25.00	25,112,356	18.85%	18,934,717	(6,177,640)
392	Transportation Equipment - Automobiles	823,465	-	823,465	10.00	82,347	9.12%	75,100	(7,246)
392	Transportation Equipment - Light Trucks	3,431,469	25,252	3,406,217	8.33	283,851	8.80%	299,747	15,896
392	Transportation Equipment - Trailers	1,099,687	104,349	995,338	6.67	66,356	5.73%	57,033	(9,323)
392	Transportation Equipment - Heavy Trucks	5,505,442	1,252,353	4,253,089	7.14	303,792	6.27%	266,669	(37,123)
393	Stores Equipment	246,162	-	246,162	5.00	12,308	4.92%	12,111	(197)
394	Tools, Shop & Garage Equipment	4,041,708	10,892	4,030,816	6.67	268,721	6.41%	258,375	(10,346)
395	Laboratory Equipment	-	-	-	10.00	-	10.00%	-	-
396	Power Operated Equipment	990,912	281,183	709,729	8.33	59,144	6.67%	47,339	(11,805)
397	Communication Equipment	964,432	248,569	715,864	11.11	79,540	7.66%	54,835	(24,705)
397	Communication Equipment - Two Way	75,068	-	75,068	11.11	8,341	9.96%	7,477	(864)
398	Miscellaneous Equipment	582,227	-	582,227	6.67	38,815	5.93%	34,526	(4,289)
	Total General	145,348,298	4,848,419	140,499,879		27,526,196		21,181,073	(6,345,123)
	Total Common Utility	524,168,448	202,239,347	321,929,101		54,658,501		50,015,212	(4,643,288)
	Total Vintage All Utilities	1,718,711,122	303,900,979	1,414,810,143		133,375,119		123,506,557	(9,868,562)
	Total ASL and Vintage All Utilities	9,051,518,808	303,900,979	8,747,617,828		310,641,196		303,738,151	(6,903,045)
	Total Electric Utility	7,275,121,206	84,108,133	7,191,013,073		216,815,238		220,498,868	3,683,630
	Total Gas Utility	1,081,906,298	17,553,499	1,064,352,799		34,004,220		27,415,620	(6,588,601)
	Total Common Utility	694,491,303	202,239,347	492,251,956		59,821,738		55,823,664	(3,998,074)
	Total ASL and Vintage All Utilities	9,051,518,808	303,900,979	8,747,617,828		310,641,196		303,738,151	(6,903,045)

APPENDIX C

Depreciation Parameter Comparison

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Depreciation Rates
Average Service Life
Electric Utility

FERC Account	Account Description	Present Average Life	Present Curve	Present Net Salvage	Proposed Average Life	Proposed Curve	Proposed Net Salvage	Difference Life	Difference Net Salvage
Transmission									
352	Structures & Improvements	68	R5	0	70	R5	-5	2	-5
353	Station Equipment	56	R2	-10	56	R2	-15	0	-5
354	Towers & Fixtures	70	R4	-35	75	R4	-35	5	0
355	Poles & Fixtures	62	R2	-35	62	R2	-50	0	-15
356	Overhead Conductor & Devices	63	R1	-30	67	R1	-35	4	-5
357	Underground Conduit	73	R4	0	73	R4	0	0	0
358	Underground Conductor & Devices	55	R2	0	50	R3	-5	-5	-5
Distribution									
361	Structures & Improvements	60	R3	-30	63	R2.5	-30	3	0
362	Station Equipment	55	R1.5	-20	53	R2	-25	-2	-5
364	Poles, Towers & Fixtures	44	R1	-100	47	R1	-120	3	-20
365	Overhead Conductor & Devices	39	L0	-20	39	L0	-25	0	-5
366	Underground Conduit	52	R3	-10	56	R3	-20	4	-10
367	Underground Conductor & Devices	45	R2.5	0	49	R1.5	-10	4	-10
369	Services - Overhead	40	R1.5	-70	42	R1.5	-85	2	-15
369	Services - Underground	41	R4	-5	44	R4	-5	3	0
373	Street Lighting & Signal Systems	29	L0	-35	29	L0	-40	0	-5
General									
390	Structures & Improvements	57	R1.5	-20	55	R1.5	-20	-2	0
390	Leasehold Improvements	10	SQ	0	10	SQ	0	0	0

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Depreciation Rates
Average Service Life
Gas Utility

FERC Account	Account Description	Present Average Life	Present Curve	Present Net Salvage	Proposed Average Life	Proposed Curve	Proposed Net Salvage	Difference Life	Difference Net Salvage
Transmission									
366	Structures & Improvements	52	R3	-5	65	R4	-5	13	0
367	Mains	75	R2.5	-15	75	R2.5	-15	0	0
369	Measure & Regulating Station Equipment	33	R1.5	-30	40	R1	-30	7	0
Distribution									
375	Structures & Improvements	41	R5	0	50	R5	-5	9	-5
376	Mains - Metallic	51	R1.5	-20	63	R2	-25	12	-5
376	Mains - Plastic	45	R2.5	-15	54	R2.5	-20	9	-5
378	Measure & Regulating Station Equipment - General	38	R0.5	-25	38	R0.5	-25	0	0
379	Measure & Regulating Station Equipment - City Gate	38	R0.5	-2	38	R0.5	-5	0	-3
380	Services - Metallic	40	S3	-40	51	R3	-40	11	0
380	Services - Plastic	39	R2.5	-30	39	R2.5	-25	0	5
General									
390	Structures & Improvements	55	R1.5	-20	55	R1.5	-14	0	6

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Depreciation Rates
Average Service Life
Common Utility

FERC Account	Account Description	Present Average Life	Present Curve	Present Net Salvage	Proposed Average Life	Proposed Curve	Proposed Net Salvage	Difference Life	Difference Net Salvage
390	Structures & Improvements	55	R1.5	-20	50	L0	-25	-5	-5
390	Structures & Improvements - Leased	10	SQ	0	10	SQ	0	0	0

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Depreciation Rates
Vintage Group
Electric Utility

		Present			Proposed			Difference	
FERC Account	Account Description	Average Life	Curve	Net Salvage	Average Life	Curve	Net Salvage	Life	Net Salvage
Intangible									
303	Intangible Computer Software - 5 Year	5	(1)	0	5	(1)	0	0	0
General									
391	Office Furniture & Equipment	20	(1)	0	20	(1)	0	0	0
391	Network Equipment	4	(1)	0	6	(1)	0	2	0
392	Transportation Equipment - Automobiles	10	(1)	0	10	(1)	5	0	5
392	Transportation Equipment - Light Trucks	12	(1)	0	10	(1)	10	-2	10
392	Transportation Equipment - Trailers	15	(1)	0	12	(1)	20	-3	20
392	Transportation Equipment - Heavy Trucks	14	(1)	0	12	(1)	15	-2	15
393	Stores Equipment	20	(1)	0	20	(1)	0	0	0
394	Tools, Shop & Garage Equipment	15	(1)	0	15	(1)	0	0	0
395	Laboratory Equipment	10	(1)	0	10	(1)	0	0	0
396	Power Operated Equipment	12	(1)	0	12	(1)	15	0	15
397	Communication Equipment	9	(1)	0	10	(1)	0	1	0
397	Communication Equipment - Two Way	9	(1)	0	10	(1)	0	1	0
397	Communication Equipment - AES	15	(1)	0	15	(1)	0	0	0
397	Communication Equipment - EMS	15	(1)	0	15	(1)	0	0	0
398	Miscellaneous Equipment	15	(1)	0	15	(1)	0	0	0
Distribution (Vintage Group Treatment)									
368	Line Transformers	32	(1)	-5	32	(1)	-5	0	0
368	Line Capacitors	25	(1)	-10	25	(1)	-7	0	3
370	Meters - Old	20	(1)	0	20	(1)	-5	0	-5
370	Meters	15	(1)	0	15	(1)	-5	0	-5

(1) No curve is used for amortized accounts.

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Depreciation Rates
Vintage Group
Gas Utility

FERC Account	Account Description	Present Average Life	Present Curve	Present Net Salvage	Proposed Average Life	Proposed Curve	Proposed Net Salvage	Difference Life	Difference Net Salvage
Intangible									
303	Intangible Computer Software - 5 Year	5	(1)	0	5	(1)	0	0	0
303	Intangible Computer Software - 10 Year	10	(1)	0	10	(1)	0	0	0
General									
391	Office Furniture & Equipment	20	(1)	0	20	(1)	0	0	0
391	Network Equipment	4	(1)	0	6	(1)	0	2	0
392	Transportation Equipment - Automobiles	10	(1)	0	10	(1)	5	0	5
392	Transportation Equipment - Light Trucks	12	(1)	0	10	(1)	10	-2	10
392	Transportation Equipment - Trailers	15	(1)	0	12	(1)	20	-3	20
392	Transportation Equipment - Heavy Trucks	14	(1)	0	12	(1)	15	-2	15
393	Stores Equipment	20	(1)	0	20	(1)	0	0	0
394	Tools, Shop & Garage Equipment	15	(1)	0	15	(1)	0	0	0
395	Laboratory Equipment	10	(1)	0	10	(1)	0	0	0
396	Power Operated Equipment	12	(1)	0	12	(1)	15	0	15
397	Communication Equipment	9	(1)	0	10	(1)	0	1	0
397	Communication Equipment - Two Way	9	(1)	0	10	(1)	0	1	0
397	Communication Equipment - AES	15	(1)	0	15	(1)	0	0	0
397	Communication Equipment - EMS	15	(1)	0	15	(1)	0	0	0
398	Miscellaneous Equipment	15	(1)	0	15	(1)	0	0	0
Distribution (Vintage Group Treatment)									
381	Meters	20	(1)	-3	20	(1)	-5	0	-2
381	Meters - Telemetering	8	(1)	0	8	(1)	0	0	0
383	House Regulators	20	(1)	0	20	(1)	-1	0	-1

(1) No curve is used for amortized accounts.

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Present and Proposed Depreciation Rates
Vintage Group
Common Utility

		Present			Proposed			Difference	
		Average Life	Curve	Net Salvage	Average Life	Curve	Net Salvage	Life	Net Salvage
303	Intangible Computer Software - 3 Year	3	(1)	0	3	(1)	0	0	0
303	Intangible Computer Software - 5 Year	5	(1)	0	5	(1)	0	0	0
303	Intangible Computer Software - 7 Year	7	(1)	0	7	(1)	0	0	0
303	Intangible Computer Software - 10 Year	10	(1)	0	10	(1)	0	0	0
303	Intangible Computer Software - 15 Year	15	(1)	0	15	(1)	0	0	0
General									
391	Office Furniture & Equipment	20	(1)	0	20	(1)	0	0	0
391	Network Equipment	4	(1)	0	5	(1)	0	1	0
392	Transportation Equipment - Automobiles	10	(1)	0	10	(1)	5	0	5
392	Transportation Equipment - Light Trucks	12	(1)	0	10	(1)	10	-2	10
392	Transportation Equipment - Trailers	15	(1)	0	12	(1)	20	-3	20
392	Transportation Equipment - Heavy Trucks	14	(1)	0	12	(1)	15	-2	15
393	Stores Equipment	20	(1)	0	20	(1)	0	0	0
394	Tools, Shop & Garage Equipment	15	(1)	0	15	(1)	0	0	0
395	Laboratory Equipment	10	(1)	0	10	(1)	0	0	0
396	Power Operated Equipment	12	(1)	0	12	(1)	15	0	15
397	Communication Equipment	9	(1)	0	10	(1)	0	1	0
397	Communication Equipment - Two Way	9	(1)	0	10	(1)	0	1	0
398	Miscellaneous Equipment	15	(1)	0	15	(1)	0	0	0

(1) No curve is used for amortized accounts.

APPENDIX D

Comparison of Book and Theoretical Depreciation Reserve

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Comparison of Actual and Theoretical Reserve
Electric Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Recoverable Cost	Theoretical Reserve	Actual Reserve	Difference
Transmission						
352	Structure & Improvements	103,086,366	103,086,366	17,398,079	16,791,010	(607,070)
353	Station Equipment	1,181,449,210	1,181,449,210	275,895,262	266,220,136	(9,675,127)
354	Towers & Fixtures	118,631,858	118,631,858	68,909,593	66,493,064	(2,416,530)
355	Poles & Fixtures	1,330,556,061	1,330,556,061	195,211,295	188,365,602	(6,845,692)
356	Overhead Conductor & Devices	532,704,102	532,704,102	92,484,304	89,241,054	(3,243,250)
357	Underground Conduit	25,910,138	25,910,138	3,857,479	3,722,204	(135,275)
358	Underground Conductor & Devices	30,710,573	30,710,573	6,968,325	6,723,959	(244,366)
	Total Transmission	3,323,048,309	3,323,048,309	660,724,337	637,557,028	(23,167,309)
Distribution - Minnesota Only						
361	Structure & Improvements	43,721,596	43,721,596	14,204,039	14,082,032	(122,007)
362	Station Equipment	552,978,032	552,978,032	195,739,418	194,058,095	(1,681,323)
364	Poles, Towers & Fixtures	343,536,905	343,536,905	195,767,725	194,086,158	(1,681,566)
365	Overhead Conductor & Devices	373,235,852	373,235,852	102,847,356	101,963,938	(883,418)
366	Underground Conduit	261,312,548	261,312,548	77,733,025	77,065,329	(667,695)
367	Underground Conductor & Devices	967,850,933	967,850,933	269,040,527	266,729,577	(2,310,950)
369	Services - Overhead	71,641,753	71,641,753	54,408,242	53,940,897	(467,345)
369	Services - Underground	185,773,119	185,773,119	83,922,749	83,201,886	(720,863)
373	Street Lighting & Signal Systems	64,184,329	64,184,329	21,101,842	20,920,586	(181,256)
	Total Distribution	2,864,235,067	2,864,235,067	1,014,764,923	1,006,048,499	(8,716,423)
General						
390	Structures and Improvements	63,508,306	63,508,306	25,927,493	23,807,986	(2,119,507)
390	Leasehold Improvements	35,652	35,652	35,652	35,652	-
	Total General	63,543,958	63,543,958	25,963,144	23,843,637	(2,119,507)
	Total Electric Utility	6,250,827,334	6,250,827,334	1,701,452,404	1,667,449,165	(34,003,239)

Xcel Energy
Comparison of Actual and Theoretical Reserve
Gas Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Recoverable Cost	Theoretical Reserve	Actual Reserve	Difference
Transmission						
366	Structure & Improvements	1,130,639	1,130,639	403,631	631,260	227,629
367	Mains	65,790,678	65,790,678	14,689,913	23,607,633	8,917,720
369	Measure & Regulating Station Equipment	13,617,811	13,617,811	3,924,334	6,322,674	2,398,340
	Total Transmission	80,539,128	80,539,128	19,017,879	30,561,568	11,543,689
Distribution - Minnesota Only						
375	Structure & Improvements	727,864	727,864	64,516	78,795	14,279
376	Mains - Metallic	135,069,020	135,069,020	38,610,427	47,649,540	9,039,114
376	Mains - Plastic	384,394,656	384,394,656	112,391,017	138,702,955	26,311,938
378	Measure & Regulating Station Equipment - General	22,768,672	22,768,672	3,670,958	4,523,719	852,761
379	Measure & Regulating Station Equipment - City Gat	1,392,566	1,392,566	246,046	303,648	57,602
380	Services - Metallic	12,590,915	12,590,915	9,287,056	11,375,605	2,088,549
380	Services - Plastic	272,681,597	272,681,597	115,177,977	142,142,133	26,964,156
	Total Distribution	829,625,290	829,625,290	279,447,997	344,776,397	65,328,400
General						
390	Structure & Improvements	1,493,079	1,493,079	269,011	70,882	(198,129)
	Total Gas Utility	911,657,497	911,657,497	298,734,887	375,408,846	76,673,959

Xcel Energy
Comparison of Actual and Theoretical Reserve
Common Utility

FERC Account	Account Description	Plant Balance 01/01/2017	Recoverable Cost	Theoretical Reserve	Actual Reserve	Difference
General						
390	Structures & Improvements	151,813,406	151,813,406	26,814,057	21,297,336	(5,516,722)
390	Structures & Improvements - Leased	18,509,449	18,509,449	1,774,458	1,409,381	(365,077)
	Total Common Utility	170,322,855	170,322,855	28,588,515	22,706,717	(5,881,799)
	Total All Utilities	7,332,807,686	7,332,807,686	2,028,775,806	2,065,564,727	36,788,921

Xcel Energy
Comparison of Actual and Theoretical Reserve
Electric Utility
Amortized Acct

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Recoverable Cost	Theoretical Reserve	Actual Reserve	Difference
Intangible							
303	Intangible Computer Software - 5 Year	115,172,555	27,811,170	87,361,384	49,893,597	44,632,341	(5,261,257)
	Total Intangible	115,172,555	27,811,170	87,361,384	49,893,597	44,632,341	(5,261,257)
General						-	
391	Office Furniture & Equipment	27,593,861	-	27,593,861	13,486,891	14,947,880	1,460,989
391	Network Equipment	32,398,061	-	32,398,061	10,809,106	11,957,884	1,148,778
392	Transportation Equipment - Automobiles	1,108,813	-	1,108,813	352,850	391,080	38,230
392	Transportation Equipment - Light Trucks	32,832,470	6,239,706	26,592,763	11,901,913	13,147,406	1,245,493
392	Transportation Equipment - Trailers	17,878,078	-	17,878,078	5,107,733	5,631,534	523,801
392	Transportation Equipment - Heavy Trucks	97,589,361	4,119,785	93,469,576	29,802,341	32,963,431	3,161,090
393	Stores Equipment	1,648,791	-	1,648,791	715,144	790,289	75,145
394	Tools, Shop & Garage Equipment	81,301,137	187,888	81,113,250	30,368,648	33,506,944	3,138,296
395	Laboratory Equipment	3,209,733	-	3,209,733	1,487,920	1,630,248	142,328
396	Power Operated Equipment	45,134,817	-	45,134,817	14,318,885	15,825,286	1,506,401
397	Communication Equipment	17,117,461	158,602	16,958,859	10,641,258	11,477,639	836,381
397	Communication Equipment - Two Way	6,532,362	-	6,532,362	603,791	669,209	65,418
397	Communication Equipment - AES	7,071,726	-	7,071,726	3,587,868	3,976,600	388,732
397	Communication Equipment - EMS	47,275,858	-	47,275,858	7,370,853	8,169,456	798,604
398	Miscellaneous Equipment	2,723,841	66,643	2,657,198	1,937,582	2,145,253	207,671
	Total General	421,416,370	10,772,624	410,643,745	142,492,783	157,230,139	14,737,356
Distribution - Minnesota Only (Vintage Group Treatment)							
368	Line Transformers	372,629,100	-	372,629,100	167,927,992	171,239,942	3,311,950
368	Line Capacitors	18,759,258	3,570,695	15,188,563	7,990,287	8,150,381	160,095
370	Meters	96,316,591	41,953,643	54,362,948	24,217,649	24,702,877	485,229
	Total Distribution	487,704,949	45,524,338	442,180,610	200,135,927	204,093,201	3,957,273
	Total Electric Utility	1,024,293,873	84,108,133	940,185,740	392,522,307	405,955,680	13,433,373

Xcel Energy
Comparison of Actual and Theoretical Reserve
Gas Utility

Amortized Acct FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Recoverable Cost	Theoretical Reserve	Actual Reserve	Difference
Intangible							
303	Intangible Computer Software - 5 Year	7,256,644	3,062,618	4,194,027	2,028,183	2,060,121	31,938
303	Intangible Computer Software - 10 Year	234,274	-	234,274	81,996	85,975	3,979
	Total Intangible	7,490,919	3,062,618	4,428,301	2,110,179	2,146,096	35,917
General							
391	Office Furniture & Equipment	906,378	-	906,378	299,696	467,586	167,890
391	Network Equipment	38,023	-	38,023	15,843	25,279	9,436
392	Transportation Equipment - Automobiles	376,943	-	376,943	42,346	67,568	25,222
392	Transportation Equipment - Light Trucks	6,054,537	847,483	5,207,054	2,113,744	3,041,760	928,016
392	Transportation Equipment - Trailers	1,504,110	50,252	1,453,858	500,374	703,350	202,977
392	Transportation Equipment - Heavy Trucks	8,425,887	725,075	7,700,813	3,062,075	4,399,984	1,337,909
393	Stores Equipment	10,091	-	10,091	2,775	4,428	1,653
394	Tools, Shop & Garage Equipment	6,257,777	(59,073)	6,316,850	1,937,549	2,856,156	918,606
396	Power Operated Equipment	2,858,219	-	2,858,219	622,370	946,052	323,682
397	Communication Equipment	4,722,283	-	4,722,283	3,635,958	4,554,658	918,700
397	Communication Equipment - Two Way	120,072	-	120,072	10,009	15,970	5,961
397	Communication Equipment - AES	15,492,768	-	15,492,768	4,108,288	6,555,265	2,446,977
397	Communication Equipment - EMS	764,413	-	764,413	223,167	356,090	132,923
398	Miscellaneous Equipment	50,705	-	50,705	33,509	42,589	9,080
	Total General	47,582,206	1,563,737	46,018,470	16,607,703	24,036,734	7,429,031
Distribution - Minnesota Only (Vintage Group Treatment)							
381	Meters	105,068,640	12,890,367	92,178,273	49,567,409	57,890,884	8,323,475
381	Meters - Telemetering	36,778	36,778	-	-	-	-
383	House Regulators	10,070,258	-	10,070,258	10,170,961	10,170,961	-
	Total Distribution	115,175,677	12,927,145	102,248,532	59,738,370	68,061,845	8,323,475
	Total Gas Utility	170,248,802	17,553,499	152,695,302	78,456,252	94,244,675	15,788,422

Xcel Energy
Comparison of Present and Proposed Accruals
Common Utility

Vintage Group

FERC Account	Account Description	Plant Balance 01/01/2017	Fully Accrued	Recoverable Cost	Theoretical Reserve	Actual Reserve	Difference
Intangible							
303.004	Computer Software- 3 Year	7,673,530	7,673,530	-	-	-	-
303.004	Computer Software- 5 Year	197,541,349	87,309,050	110,232,298	50,650,961	46,278,871	(4,372,090)
303.004	Computer Software- 7 Year	44,140,612	44,140,612	-	-	-	
303.004	Computer Software- 10 Year	68,449,240	58,267,735	10,181,505	3,932,060	3,592,653	(339,408)
303	Computer Software- 15 Year	61,015,418	-	61,015,418	3,856,103	3,523,252	(332,851)
	Total Intangible	378,820,150	197,390,928	181,429,222	58,439,124	53,394,775	(5,044,349)
General Plant							
391	Office Furniture & Equipment	27,141,560	2,929,083	24,212,478	11,576,010	12,392,643	816,633
391	Network Equipment	100,446,164	(3,261)	100,449,425	43,563,951	46,846,249	3,282,299
392	Transportation Equipment - Automobiles	823,465	-	823,465	270,044	290,391	20,346
392	Transportation Equipment - Light Trucks	3,431,469	25,252	3,406,217	1,899,106	1,924,475	25,369
392	Transportation Equipment - Trailers	1,099,687	104,349	995,338	517,724	556,732	39,008
392	Transportation Equipment - Heavy Trucks	5,505,442	1,252,353	4,253,089	2,360,145	2,504,271	144,126
393	Stores Equipment	246,162	-	246,162	41,047	44,140	3,093
394	Tools, Shop & Garage Equipment	4,041,708	10,892	4,030,816	1,378,370	1,481,774	103,404
395	Laboratory Equipment	-	-	-	-	-	-
396	Power Operated Equipment	990,912	281,183	709,729	264,275	284,187	19,912
397	Communication Equipment	964,432	248,569	715,864	541,718	582,533	40,815
397	Communication Equipment - Two Way	75,068	-	75,068	3,753	4,036	283
398	Miscellaneous Equipment	582,227	-	582,227	400,574	420,760	20,186
				-			
	Total General	145,348,298	4,848,419	140,499,879	62,816,718	67,332,190	4,515,473
	Total Common Utility	524,168,448	202,239,347	321,929,101	121,255,842	120,726,966	(528,876)
	Total Vintage All Utilities	1,718,711,122	303,900,979	1,414,810,143	592,234,402	620,927,321	28,692,919
	Total ASL and Vintage All Utilities	9,051,518,808	303,900,979	8,747,617,828	2,621,010,208	2,686,492,048	65,481,840

APPENDIX E

Net Salvage Analysis

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Structures & Improvements
Account 352
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	896	1,731	1,775	(44)	-4.91%									
1951	1,487	199	528	(329)	-22.13%	-15.65%								
1952	2,385	503	316	187	7.84%	-3.67%	-3.90%							
1953	538	38	246	(208)	-38.66%	-0.72%	-7.94%	-7.43%						
1954	11,453	1,211	514	697	6.09%	4.08%	4.70%	2.19%	1.81%					
1955	3,562	69	424	(355)	-9.97%	2.28%	0.86%	1.79%	-0.04%	-0.26%				
1956	181	50	(8)	58	32.04%	-7.93%	2.63%	1.22%	2.09%	0.26%	0.03%			
1957	3,790	4,473	371	4,102	108.23%	104.76%	50.51%	23.71%	21.99%	20.45%	17.75%	16.91%		
1958	698	-	387	(387)	-55.44%	82.78%	80.81%	41.53%	20.91%	19.32%	18.11%	15.63%	14.89%	
1959	3,809	1,309	499	810	21.27%	9.39%	54.54%	54.06%	35.12%	20.96%	19.63%	18.56%	16.40%	15.73%
1960	6,773	-	1,048	(1,048)	-15.47%	-2.25%	-5.54%	23.07%	23.18%	16.90%	12.81%	11.91%	11.62%	10.17%
1961	-	-	4	(4)	NA	-15.53%	-2.29%	-5.58%	23.05%	23.15%	16.88%	12.80%	11.90%	11.61%
1962	-	-	-	0	NA	NA	-15.53%	-2.29%	-5.58%	23.05%	23.15%	16.88%	12.80%	11.90%
1963	7766	-	-	0	0.00%	0.00%	-0.05%	-7.24%	-1.32%	-3.30%	15.21%	15.34%	11.95%	10.18%
1964	847	63	169	(106)	-12.51%	-1.23%	-1.23%	-1.28%	-7.53%	-1.81%	-3.69%	14.22%	14.35%	11.19%
1965	-	-	-	0	NA	-12.51%	-1.23%	-1.23%	-1.28%	-7.53%	-1.81%	-3.69%	14.22%	14.35%
1966	1820	-	899	(899)	-49.40%	-49.40%	-37.68%	-9.63%	-9.63%	-9.67%	-11.96%	-5.93%	-7.53%	9.68%
1967	-	-	-	0	NA	-49.40%	-49.40%	-37.68%	-9.63%	-9.63%	-9.67%	-11.96%	-5.93%	-7.53%
1968	1262	157	116	41	3.25%	3.25%	-27.84%	-27.84%	-24.54%	-8.24%	-8.24%	-8.28%	-10.92%	-5.41%
1969	1221	-	-	0	0.00%	1.65%	1.65%	-19.94%	-19.94%	-18.72%	-7.46%	-7.46%	-7.49%	-10.24%
1970	67	-	272	(272)	-405.97%	-21.12%	-9.06%	-9.06%	-25.86%	-25.86%	-23.69%	-9.52%	-9.52%	-9.55%
1971	7298	82	-	82	1.12%	-2.58%	-2.21%	-1.51%	-1.51%	-8.98%	-8.98%	-9.22%	-5.69%	-5.69%
1972	1105	100	181	(81)	-7.33%	0.01%	-3.20%	-2.80%	-2.10%	-2.10%	-8.84%	-8.84%	-9.07%	-5.77%
1973	-	150	304	(154)	NA	-21.27%	-1.82%	-5.02%	-4.39%	-3.51%	-3.51%	-10.04%	-10.04%	-10.20%
1974	-	-	-	0	NA	NA	-21.27%	-1.82%	-5.02%	-4.39%	-3.51%	-3.51%	-10.04%	-10.04%
1975	-	-	144	(144)	NA	NA	NA	-34.30%	-3.53%	-6.72%	-5.87%	-4.82%	-4.82%	-11.17%
1976	906	30	20	10	1.10%	-14.79%	-14.79%	-31.79%	-18.35%	-3.08%	-5.96%	-5.28%	-4.37%	-4.37%
1977	7646	30,541	1,288	29,253	382.59%	342.18%	340.49%	340.49%	338.69%	299.10%	170.84%	168.57%	157.29%	147.32%
1978	862	-	29	(29)	-3.36%	343.49%	310.54%	309.01%	309.01%	307.37%	274.31%	162.41%	160.28%	150.04%
1979	763	-	-	0	0.00%	-1.78%	315.22%	287.26%	285.84%	285.84%	284.33%	255.76%	155.74%	153.72%
1980	7535	527	465	62	0.82%	0.75%	0.36%	174.26%	165.40%	164.59%	164.59%	163.72%	153.67%	111.04%
1981	1415	-	95	(95)	-6.71%	-0.37%	-0.34%	-0.59%	160.21%	152.67%	151.92%	151.92%	151.11%	142.46%
1982	4801	-	50	(50)	-1.04%	-2.33%	-0.60%	-0.57%	-0.73%	126.58%	121.83%	121.23%	121.23%	120.58%
1983	26150	1,249	3,697	(2,448)	-9.36%	-8.07%	-8.01%	-6.34%	-6.22%	-6.16%	54.28%	53.32%	53.04%	53.04%
1984	281115	-	-	0	0.00%	-0.80%	-0.80%	-0.83%	-0.79%	-0.79%	-0.79%	8.08%	8.06%	8.02%
1985	610	5,816	-	5,816	953.44%	2.06%	1.09%	1.06%	1.03%	1.02%	1.02%	1.01%	9.82%	9.80%
1986	358	86,263	34	86,229	24086.31%	9508.78%	32.63%	29.07%	28.61%	28.45%	27.80%	27.74%	27.65%	35.84%
1987	99	29,269	264	29,005	29297.98%	25215.32%	11344.89%	42.90%	38.47%	37.86%	37.66%	36.80%	36.71%	36.60%
1988	-	-	-	0	NA	29297.98%	25215.32%	11344.89%	42.90%	38.47%	37.86%	37.66%	36.80%	36.71%
1989	1577	-	-	0	0.00%	0.00%	1730.61%	5665.39%	4578.29%	42.66%	38.27%	37.67%	37.47%	36.62%
1990	-	-	-	0	NA	0.00%	0.00%	1730.61%	5665.39%	4578.29%	42.66%	38.27%	37.67%	37.47%
1991	399	-	540	(540)	-135.34%	-135.34%	-27.33%	-27.33%	1371.81%	4714.10%	3960.24%	42.41%	38.05%	37.45%
1992	-	-	-	0	NA	-135.34%	-135.34%	-27.33%	-27.33%	1371.81%	4714.10%	3960.24%	42.41%	38.05%
1993	-	-	-	0	NA	NA	-135.34%	-135.34%	-27.33%	-27.33%	1371.81%	4714.10%	3960.24%	42.41%
1994	-	-	-	0	NA	NA	NA	-135.34%	-135.34%	-27.33%	-27.33%	1371.81%	4714.10%	3960.24%
1995	-	-	-	0	NA	NA	NA	NA	-135.34%	-135.34%	-27.33%	-27.33%	1371.81%	4714.10%
1996	226	-	7,845	(7,845)	-3471.24%	-3471.24%	-3471.24%	-3471.24%	-3471.24%	-1341.60%	-1341.60%	-380.79%	-380.79%	896.13%
1997	100	-	572	(572)	-572.00%	-2581.90%	-2581.90%	-2581.90%	-2581.90%	-2581.90%	-1235.45%	-1235.45%	-389.10%	-389.10%
1998	7266	-	13,664	(13,664)	-188.05%	-193.27%	-290.85%	-290.85%	-290.85%	-290.85%	-290.85%	-283.08%	-283.08%	-236.42%
1999	1369	-	1,254	(1,254)	-91.60%	-172.76%	-177.33%	-260.41%	-260.41%	-260.41%	-260.41%	-260.41%	-255.07%	-255.07%
2000	20274	2,888	195	2,693	13.28%	6.65%	-42.29%	-44.11%	-70.61%	-70.61%	-70.61%	-70.61%	-70.61%	-71.48%
2001	-	-	-	0	NA	13.28%	6.65%	-42.29%	-44.11%	-70.61%	-70.61%	-70.61%	-70.61%	-70.61%
2002	167	-	-	0	0.00%	0.00%	13.17%	6.60%	-42.04%	-43.86%	-70.21%	-70.21%	-70.21%	-70.21%
2003	-	-	(293,236)	293,236	NA	175590.56%	175590.56%	1447.72%	1351.10%	966.47%	961.20%	927.13%	927.13%	927.13%
2004	-	-	-	0	NA	NA	175590.56%	175590.56%	1447.72%	1351.10%	966.47%	961.20%	927.13%	927.13%
2005	302.4	-	265,029	(265,029)	-87641.87%	-87641.87%	9327.79%	6009.21%	6009.21%	148.96%	134.07%	54.40%	52.28%	25.47%
2006	29998.99	-	-	0	0.00%	-874.64%	-874.64%	93.09%	92.58%	92.58%	60.90%	56.89%	26.92%	25.91%
2007	-	-	6,761	(6,761)	NA	-22.54%	-896.96%	-896.96%	70.78%	70.39%	70.39%	47.57%	43.92%	15.53%
2008	18372.08	-	6,167	(6,167)	-33.57%	-70.37%	-26.73%	-571.06%	-571.06%	31.39%	31.28%	31.28%	26.00%	23.72%
2009	27,066.74	0.00	-	0	0.00%	-13.57%	-28.45%	-17.14%	-366.99%	-366.99%	20.17%	20.13%	20.13%	18.69%
2010	34,423.64	0	865	(865)	-2.51%	-1.41%	-8.81%	-17.27%	-12.56%	-253.10%	-253.10%	13.08%	13.06%	13.06%
2011	10,040.30	0	-	0	0.00%	-1.95%	-1.21%	-7.82%	-15.34%	-11.50%	-231.96%	-231.96%	11.99%	11.97%
2012	4,777.00	0	2,381	(2,381)	-49.84%	-16.07%	-6.59%	-4.25%	-9.94%	-17.08%	-12.97%	-225.00%	-225.00%	9.63%
2013	70,691.00	2,866	11,272	(8,406)	-11.89%	-14.29%	-12.62%	-9.72%	-7.93%	-10.78%	-14.86%	-12.58%	-148.01%	-148.01%
2014	5,105.00	0	24,713	(24,713)	-484.09%	-43.69%	-44.06%	-39.18%	-29.08%	-23.91%	-24.95%	-28.92%	-24.59%	-156.55%
2015	70,653.00	0	2	(2)	0.00%	-32.62%	-22.62%	-23.48%	-22.01%	-18.58%	-16.33%	-17.64%	-20.44%	-18.18%
2016	34,538.00	3,552	28,076	(24,524)	-71.01%	-23.32%	-44.64%	-31.85%	-32.31%	-30.66%	-26.45%	-23.67%	-24.33%	-26.78%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Station Equipment
Account 353
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	191,964	176,340	48,541	127,799	66.57%									
1951	70,561	180,071	42,101	137,970	195.53%	101.24%								
1952	159,975	54,947	23,152	31,795	19.87%	73.64%	70.43%							
1953	110,652	79,731	13,886	65,845	59.51%	36.08%	69.06%	68.16%						
1954	116,832	31,302	23,187	8,115	6.95%	32.51%	27.29%	53.21%	57.16%					
1955	146,434	87,842	9,116	78,726	53.76%	32.99%	40.83%	34.55%	53.35%	56.53%				
1956	74,919	50,355	8,746	41,609	55.54%	54.36%	37.98%	43.29%	37.14%	53.59%	56.45%			
1957	88,488	12,975	5,396	7,579	8.57%	30.10%	41.28%	31.88%	37.57%	33.51%	48.40%	52.03%		
1958	410,941	163,277	53,339	109,938	26.75%	23.53%	27.71%	33.00%	29.37%	32.88%	31.00%	40.85%	44.46%	
1959	397,946	118,581	18,089	100,492	25.25%	26.01%	24.29%	26.70%	30.24%	28.04%	30.63%	29.48%	36.92%	40.13%
1960	549,879	386,301	41,072	345,229	62.78%	47.03%	40.89%	38.92%	39.74%	40.97%	38.74%	39.95%	38.39%	43.60%
1961	159,757	59,808	9,108	50,700	31.74%	55.79%	44.82%	39.93%	38.20%	38.98%	40.16%	38.17%	39.31%	37.91%
1962	389,752	161,049	54,014	107,035	27.46%	28.70%	45.75%	40.30%	37.38%	36.11%	36.81%	37.93%	36.38%	37.43%
1963	72,639	24,783	9,442	15,341	21.12%	26.47%	27.82%	44.22%	39.41%	36.79%	35.58%	36.28%	37.40%	35.92%
1964	726,080	297,566	85,882	211,684	29.15%	28.42%	28.11%	28.54%	38.46%	36.17%	34.74%	33.91%	34.48%	35.41%
1965	225,943	84,153	5,444	78,709	34.84%	30.50%	29.84%	29.18%	29.44%	38.07%	36.05%	34.75%	33.98%	34.50%
1966	507,545	192,714	26,904	165,810	32.67%	33.34%	31.26%	30.78%	30.10%	30.23%	37.03%	35.48%	34.44%	33.79%
1967	279,550	35,831	3,231	32,600	11.66%	25.21%	27.36%	28.11%	27.83%	27.76%	28.03%	34.59%	33.47%	32.73%
1968	486,289	167,934	18,934	149,000	30.64%	23.71%	27.28%	28.42%	28.66%	28.42%	28.28%	28.48%	34.03%	33.11%
1969	508,667	126,873	46,479	80,394	15.80%	23.06%	20.56%	24.01%	25.22%	26.27%	26.14%	26.30%	26.56%	31.66%
1970	736,674	216,280	80,729	135,551	18.40%	17.34%	21.08%	19.77%	22.37%	23.39%	24.60%	24.53%	24.82%	25.09%
1971	531,867	201,148	98,705	102,443	19.26%	18.76%	17.92%	20.65%	19.66%	21.83%	22.72%	23.89%	23.84%	24.16%
1972	248,789	83,290	17,122	66,168	26.60%	21.60%	20.05%	18.98%	21.24%	20.28%	22.18%	23.00%	24.05%	24.00%
1973	423,612	132,467	69,255	63,212	14.92%	19.24%	19.25%	18.93%	18.28%	20.33%	19.57%	21.36%	22.13%	23.22%
1974	200,482	25,328	16,391	8,937	4.46%	11.56%	15.85%	17.14%	17.57%	17.23%	19.31%	18.69%	20.49%	21.28%
1975	362,121	119,581	48,000	71,581	19.77%	14.31%	14.57%	17.00%	17.68%	17.89%	17.54%	19.36%	18.79%	20.43%
1976	379,610	312,892	69,690	243,202	64.07%	42.44%	34.36%	28.33%	28.06%	25.88%	23.97%	22.75%	23.74%	22.92%
1977	801,014	206,243	101,718	104,525	13.05%	29.45%	27.18%	24.57%	22.68%	23.08%	22.39%	21.60%	20.89%	21.91%
1978	491,438	136,324	60,333	75,991	15.46%	13.97%	25.34%	24.35%	22.56%	21.35%	21.80%	21.40%	20.87%	20.32%
1979	648,564	132,686	108,806	23,880	3.68%	8.76%	10.53%	19.29%	19.35%	18.32%	17.88%	18.49%	18.59%	18.56%
1980	896,318	233,732	200,756	32,976	3.68%	3.68%	6.52%	8.37%	14.94%	15.43%	14.85%	14.85%	15.51%	15.91%
1981	96,150	130,929	69,919	61,010	63.45%	9.47%	7.18%	9.09%	10.17%	16.35%	16.68%	16.05%	15.94%	16.52%
1982	538,499	(26,070)	141,399	(167,469)	-31.10%	-16.77%	-4.80%	-2.28%	0.99%	3.77%	9.71%	10.58%	10.30%	10.70%
1983	1,076,523	132,045	18,020	114,025	10.59%	-3.31%	0.44%	1.55%	1.98%	3.75%	5.39%	9.91%	10.58%	10.36%
1984	3,778,188	299,712	168,894	130,818	3.46%	5.04%	1.43%	2.52%	2.68%	2.78%	3.60%	4.51%	7.11%	7.61%
1985	1,333,389	55,528	177,732	(122,204)	-9.16%	0.17%	1.98%	-0.67%	0.24%	0.64%	0.87%	1.68%	2.62%	4.95%
1986	681,949	197,685	121,556	76,129	11.16%	-2.29%	1.46%	2.89%	0.42%	1.23%	1.49%	1.65%	2.36%	3.19%
1987	1,495,011	307,955	393,909	(85,954)	-5.75%	-0.45%	-3.76%	-0.02%	1.35%	-0.61%	0.07%	0.40%	0.60%	1.26%
1988	367,753	114,656	102,754	11,902	3.24%	-3.98%	0.08%	-3.10%	0.14%	1.43%	-0.46%	0.19%	0.50%	0.69%
1989	783,633	281,424	111,715	169,709	21.66%	15.77%	3.61%	5.16%	1.06%	2.14%	3.09%	1.26%	1.85%	2.00%
1990	989,156	22,256	96,524	(74,268)	-7.51%	5.38%	5.01%	0.59%	2.26%	-0.44%	1.13%	2.10%	0.48%	1.02%
1991	802,610	53,860	210,915	(157,055)	-19.57%	-12.91%	-2.39%	-1.69%	-3.06%	-1.16%	-2.82%	-0.50%	0.56%	-0.88%
1992	2,030,582	2,259	69,634	(67,375)	-3.32%	-7.92%	-7.81%	-2.80%	-2.35%	-3.14%	-1.77%	-2.94%	-0.96%	-0.03%
1993	1,561,351	13,192	148,591	(135,399)	-8.67%	-5.65%	-8.19%	-8.06%	-4.29%	-3.86%	-4.21%	-3.01%	-3.83%	-1.84%
1994	710,094	314,444	207,985	106,459	14.99%	-1.27%	-2.24%	-4.96%	-5.38%	-2.30%	-2.02%	-2.65%	-1.65%	-2.59%
1995	3,944,102	16,898	264,933	(248,035)	-6.29%	-3.04%	-4.46%	-4.18%	-5.54%	-5.73%	-3.75%	-3.52%	-3.78%	-3.02%
1996	1,224,121	440,616	149,425	291,191	23.79%	0.84%	2.55%	0.19%	-0.56%	-2.05%	-2.53%	-0.95%	-0.83%	-1.36%
1997	914,410	637,637	155,031	482,606	52.78%	36.18%	8.64%	9.31%	5.95%	4.14%	2.43%	1.63%	2.84%	2.85%
1998	831,318	18,885	241,920	(223,035)	-26.83%	14.87%	18.55%	4.38%	5.37%	2.98%	1.84%	0.41%	-0.19%	1.05%
1999	1,315,619	36,091	156,238	(120,147)	-9.13%	-15.98%	4.55%	10.05%	2.22%	3.23%	1.46%	0.69%	-0.53%	-1.01%
2000	1,639,005	(1,744)	190,275	(192,019)	-11.72%	-10.57%	-14.14%	-1.12%	4.03%	-0.10%	0.92%	-0.32%	-0.75%	-1.76%
2001	39,440	(3,176)	17,727	(20,903)	-53.00%	-12.69%	-11.12%	-14.54%	-1.55%	3.65%	-0.31%	0.72%	-0.49%	-0.89%
2002	1,859,766		-	0	0.00%	-1.10%	-6.02%	-6.86%	-9.78%	-1.11%	2.78%	-0.26%	0.61%	-0.42%
2003	1,085,106	(1,209)	381,872	(383,081)	-35.30%	-13.01%	-13.54%	-12.89%	-12.06%	-13.87%	-5.94%	-1.86%	-3.22%	-2.26%
2004	542,834		41,245	(41,245)	-7.60%	-26.07%	-12.17%	-12.62%	-12.34%	-11.69%	-13.41%	-6.05%	-2.19%	-3.39%
2005	2,000,659	4,383	52,568	(48,185)	-2.41%	-3.52%	-13.02%	-8.61%	-8.93%	-9.56%	-9.50%	-11.04%	-5.34%	-2.23%
2006	3,692,015	550	130,120	(129,570)	-3.51%	-3.12%	-3.51%	-8.22%	-6.56%	-6.76%	-7.51%	-7.68%	-8.91%	-4.85%
2007	1,694,619	7,351	460,554	(453,203)	-26.74%	-10.82%	-8.54%	-8.48%	-11.71%	-9.70%	-9.86%	-10.10%	-10.01%	-10.96%
2008	5,601,754	6,241	479,200	(472,959)	-8.44%	-12.69%	-9.61%	-8.50%	-8.46%	-10.46%	-9.28%	-9.38%	-9.59%	-9.56%
2009	4,134,752	171,442	1,930,047	(1,758,605)	-42.53%	-22.92%	-23.49%	-18.61%	-16.72%	-16.44%	-17.53%	-15.95%	-16.02%	-15.70%
2010	3,712,372	274,770	1,252,152	(977,382)	-26.33%	-34.87%	-23.86%	-24.18%	-20.13%	-18.43%	-18.15%	-18.98%	-17.53%	-17.59%
2011	1,981,644	53,259	535,803	(482,544)	-24.35%	-25.64%	-32.75%	-23.92%	-24.20%	-20.53%	-18.94%	-18.68%	-19.42%	-18.04%
2012	4,500,809.00	220,390	887,873	(667,483)	-14.83%	-17.74%	-20.87%	-27.12%	-21.87%	-22.25%	-19.52%	-18.27%	-18.06%	-18.70%
2013	12,886,849.00	124,426	1,958,717	(1,834,291)	-14.23%	-14.39%	-15.41%	-17.16%	-21.02%	-18.87%	-19.26%	-17.74%	-16.97%	-16.85%
2014	611,451.00	722,177	425,055	297,122	48.59%	-11.39%	-12.25%	-13.45%	-15.47%	-19.49%	-17.64%	-18.08%	-16.69%	-15.99%
2015	3,507,159.00	11,006	739,545	(728,539)	-20.77%	-10.47%	-13.32%	-13.64%	-14.54%	-16.15%	-19.63%	-17.94%	-18.32%	-17.03%
2016	718,155.00	76,216	905,860	(829,644)	-115.52%	-36.88%	-26.07%	-17.46%	-16.93%	-17.54%	-18.71%	-21.78%	-19.80%	-20.10%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Towers & Fixtures
Account 354
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	5,137	1,126	1,198	(72)	-1.40%									
1951	4,469	1,211	1,883	(672)	-15.04%	-7.75%								
1952	17,453	3,625	6,653	(3,028)	-17.35%	-16.88%	-13.94%							
1953	95,405	25	1,152	(1,127)	-1.18%	-3.68%	-4.11%	-4.00%						
1954	28,378	6,829	22,713	(15,884)	-55.97%	-13.74%	-14.19%	-14.21%	-13.78%					
1955	48,056	11,358	3,906	7,452	15.51%	-11.03%	-5.56%	-6.65%	-6.84%	-6.70%				
1956	75,376	20,286	10,283	10,003	13.27%	14.14%	1.03%	0.18%	-0.98%	-1.21%	-1.21%			
1957	15,608	(4,253)	3,233	(7,486)	-47.96%	2.77%	7.17%	-3.53%	-2.68%	-3.59%	-3.77%	-3.73%		
1958	4,259	142	473	(331)	-7.77%	-39.35%	2.30%	6.73%	-3.64%	-2.76%	-3.66%	-3.83%	-3.79%	
1959	27,921	2,034	4,693	(2,659)	-9.52%	-9.29%	-21.92%	-0.38%	4.08%	-4.46%	-3.40%	-4.18%	-4.33%	-4.29%
1960	139,212	8,729	11,417	(2,688)	-1.93%	-3.20%	-3.31%	-7.04%	-1.20%	1.38%	-3.42%	-2.93%	-3.49%	-3.60%
1961	80	9,850	116	9,734	12167.50%	5.06%	2.62%	2.37%	-1.83%	2.50%	4.52%	-0.55%	-0.69%	-1.33%
1962	65,157	5,507	6,346	(839)	-1.29%	13.63%	3.04%	1.53%	1.36%	-1.69%	1.75%	3.51%	-0.67%	-0.77%
1963	11,484	1,946	416	1,530	13.32%	0.90%	13.59%	3.58%	2.08%	1.91%	-1.04%	2.14%	3.80%	-0.28%
1964	42,181	12,565	4,938	7,627	18.08%	17.06%	7.00%	15.18%	5.95%	4.44%	4.26%	1.60%	3.91%	5.20%
1965	108,461	32,823	25,965	6,858	6.32%	9.62%	9.88%	6.68%	10.96%	6.06%	4.96%	4.82%	2.83%	4.44%
1966	66,602	11,585	23,391	(11,806)	-17.73%	-2.83%	1.23%	1.84%	1.15%	4.46%	2.40%	1.68%	1.60%	-0.01%
1967	24,852	3,837	2,376	1,461	5.88%	-11.31%	-1.74%	1.71%	2.24%	1.52%	4.57%	2.59%	1.90%	1.81%
1968		21,334	109	21,225	NA	91.28%	11.90%	8.87%	10.48%	10.61%	8.17%	11.23%	7.23%	6.26%
1969	126,023	5,071	4,382	689	0.55%	17.39%	15.49%	5.32%	5.65%	7.08%	7.27%	6.01%	8.20%	5.79%
1970	19,867	22,427	13,606	8,821	44.40%	6.52%	21.07%	18.86%	8.59%	7.88%	8.99%	9.11%	7.65%	9.75%
1971	252,127	35,726	22,723	13,003	5.16%	8.02%	5.66%	10.99%	10.69%	6.82%	6.73%	7.48%	7.58%	6.78%
1972	61,161	(2,185)	13,532	(15,717)	-25.70%	-0.87%	1.83%	1.48%	6.10%	6.09%	3.21%	3.72%	4.59%	4.73%
1973	149,420	42,544	17,215	25,329	16.95%	4.56%	4.89%	6.51%	5.28%	8.77%	8.65%	6.14%	6.17%	6.76%
1974	49,170	18,174	4,985	13,189	26.82%	19.40%	8.78%	6.99%	8.39%	6.89%	10.12%	9.96%	7.50%	7.35%
1975	23,642	14,772	17,507	(2,735)	-11.57%	14.36%	16.10%	7.08%	6.18%	7.54%	6.25%	9.36%	9.24%	6.92%
1976	-	22,717	10,400	12,317	NA	40.53%	31.27%	21.64%	11.43%	8.48%	9.76%	8.06%	11.17%	10.98%
1977	169,482	70,815	29,259	41,556	24.52%	31.79%	26.48%	26.55%	22.89%	16.33%	12.33%	13.21%	11.34%	13.83%
1978	350,643	257,809	41,825	215,984	61.60%	49.52%	51.88%	49.12%	47.28%	41.17%	36.08%	28.70%	28.99%	26.00%
1979	18,201	9,958	12,121	(2,163)	-11.88%	57.97%	47.44%	49.73%	47.15%	45.51%	39.90%	35.02%	28.01%	28.31%
1980	100,524	18,387	14,219	4,168	4.15%	1.69%	46.44%	40.63%	42.55%	40.62%	39.67%	35.73%	31.65%	25.97%
1981	29,197	1,775	5,039	(3,264)	-11.18%	0.70%	-0.85%	43.07%	38.36%	40.21%	38.44%	37.67%	34.19%	30.34%
1982	5,835	(33,129)	9,454	(42,583)	-729.79%	-130.87%	-30.75%	-28.51%	34.13%	31.71%	33.54%	32.01%	31.67%	29.21%
1983	122,176	29,994	41,975	(11,981)	-9.81%	-42.62%	-36.78%	-20.82%	-20.23%	25.56%	25.34%	26.89%	25.78%	25.84%
1984	-	19,000	-	19,000	NA	5.74%	-27.78%	-24.70%	-13.45%	-13.34%	28.59%	27.73%	29.27%	28.10%
1985	1,470	72,266	635	71,631	4872.86%	6165.37%	63.61%	27.86%	20.67%	14.26%	12.55%	39.93%	36.66%	38.20%
1986	771,164	304,620	126,208	178,412	23.14%	32.36%	34.82%	28.73%	23.81%	22.72%	20.90%	20.33%	30.67%	30.01%
1987	85,031	597,823	23,267	574,556	675.70%	87.94%	96.14%	98.36%	84.87%	80.05%	77.43%	70.82%	69.49%	67.63%
1988	6,013	(606,158)	2,157	(608,315)	-10116.66%	-37.08%	16.78%	25.04%	27.24%	22.65%	18.22%	17.38%	16.20%	15.75%
1989	298,129	84,516	154,395	(69,879)	-23.44%	-222.99%	-26.63%	6.44%	12.60%	14.24%	11.95%	8.59%	8.16%	7.87%
1990	32,696	83,803	18,930	64,873	198.41%	-1.51%	-182.08%	-9.19%	11.71%	17.69%	19.28%	16.58%	13.29%	12.76%
1991	9,185	4,127	3,153	974	10.60%	157.22%	-1.19%	-176.97%	-8.77%	11.70%	17.63%	19.21%	16.54%	13.27%
1992	7,695	(71)	1,568	(1,639)	-21.30%	-3.94%	129.51%	-1.63%	-173.58%	-8.99%	11.49%	17.39%	18.95%	16.32%
1993	1,675	2,196	3,800	(1,604)	-95.76%	-34.61%	-12.23%	122.15%	-2.08%	-173.21%	-9.32%	11.34%	17.23%	18.80%
1994	70,269	(2,585)	17,612	(20,197)	-28.74%	-30.30%	-29.43%	-25.29%	34.90%	-6.55%	-149.36%	-11.99%	9.14%	14.71%
1995	69,321	3,601	49,139	(45,538)	-65.69%	-47.09%	-47.67%	-46.31%	-43.00%	-1.64%	-14.93%	-137.65%	-18.41%	5.30%
1996	58,445	1,437	27,924	(26,487)	-45.32%	-56.37%	-46.57%	-46.98%	-46.03%	-43.63%	-11.88%	-18.18%	-127.90%	-20.87%
1997	164,171	22,683	136,727	(114,044)	-69.47%	-63.13%	-63.74%	-56.95%	-57.13%	-56.38%	-54.77%	-34.75%	-30.01%	-114.53%
1998	64,321	157,833	59,740	98,093	152.51%	-6.98%	-14.79%	-24.69%	-25.36%	-25.64%	-25.56%	-24.81%	-9.54%	-14.88%
1999	79,359	80,232	130,791	(50,559)	-63.71%	33.08%	-21.60%	-25.39%	-31.80%	-31.38%	-31.59%	-31.44%	-30.70%	-17.25%
2000	60,059	214,554	(40,817)	255,371	425.20%	146.90%	148.67%	51.33%	38.08%	23.57%	17.08%	16.74%	16.23%	16.15%
2001	-	-	-	0	NA	425.20%	146.90%	148.67%	51.33%	38.08%	23.57%	17.08%	16.74%	16.23%
2002	-	-	-	0	NA	NA	425.20%	146.90%	148.67%	51.33%	38.08%	23.57%	17.08%	16.74%
2003	2,106	-	8,428	(8,428)	-400.19%	-400.19%	-400.19%	397.24%	138.76%	143.06%	48.76%	35.93%	21.78%	15.53%
2004	-	-	-	0	NA	-400.19%	-400.19%	-400.19%	397.24%	138.76%	143.06%	48.76%	35.93%	21.78%
2005	48,071	2,048	-	2,048	4.26%	4.26%	-12.71%	-12.71%	-12.71%	225.87%	104.66%	116.78%	43.65%	32.74%
2006	33,506	-	2,918	(2,918)	-8.71%	-1.07%	-1.07%	-11.11%	-11.11%	-11.11%	171.19%	87.63%	102.15%	39.76%
2007	703,227	15,884	324,292	(308,408)	-43.86%	-42.26%	-39.41%	-39.41%	-40.37%	-40.37%	-40.37%	-7.36%	-12.19%	-1.49%
2008	234,988	34,836	101,780	(66,944)	-28.49%	-40.01%	-38.93%	-36.89%	-36.89%	-37.64%	-37.64%	-37.64%	-11.95%	-15.49%
2009	105,709	1,658	150,046	(148,388)	-140.37%	-63.20%	-50.17%	-48.88%	-46.61%	-46.61%	-47.27%	-47.27%	-47.27%	-23.38%
2010	173,217	9,004	455,095	(446,091)	-257.53%	-213.13%	-128.70%	-79.68%	-77.78%	-74.74%	-74.74%	-75.27%	-75.27%	-75.27%
2011	237,279	69,915	149,116	(79,201)	-33.38%	-127.97%	-130.51%	-98.59%	-72.13%	-70.70%	-68.35%	-68.35%	-68.81%	-68.81%
2012	12,067	1,445	111,364	(109,919)	-910.91%	-75.85%	-150.32%	-148.33%	-111.44%	-79.03%	-77.46%	-74.92%	-74.92%	-75.36%
2013	70,570.00	7,996	79,968	(71,972)	-101.99%	-220.11%	-81.61%	-143.41%	-142.87%	-110.64%	-80.08%	-78.56%	-76.10%	-76.10%
2014	40,284.00	180	30,660	(30,480)	-75.66%	-92.42%	-172.77%	-80.95%	-138.29%	-138.63%	-109.02%	-79.97%	-78.49%	-76.09%
2015	10,264.00	3,645	37,334	(33,689)	-328.22%	-126.95%	-112.40%	-184.75%	-87.80%	-141.88%	-141.63%	-111.57%	-81.58%	-80.07%
2016		0		0	NA	-328.22%	-126.95%	-112.40%	-184.75%	-87.80%	-141.88%	-141.63%	-111.57%	-81.58%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Poles & Fixtures
Account 355
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	70,100	32,402	22,397	10,005	14.27%									
1951	50,082	22,546	19,593	2,953	5.90%	10.78%								
1952	201,436	36,689	39,127	(2,438)	-1.21%	0.20%	3.27%							
1953	206,370	35,077	43,073	(7,996)	-3.87%	-2.56%	-1.63%	0.48%						
1954	127,421	24,869	53,065	(28,196)	-22.13%	-10.84%	-7.22%	-6.10%	-3.92%					
1955	91,662	29,835	26,367	3,468	3.78%	-11.29%	-7.69%	-5.61%	-4.76%	-2.97%				
1956	128,899	28,462	57,629	(29,167)	-22.63%	-11.65%	-15.49%	-11.16%	-8.51%	-7.62%	-5.86%			
1957	167,895	43,254	60,301	(17,047)	-10.15%	-15.57%	-11.00%	-13.75%	-10.93%	-8.81%	-8.05%	-6.55%		
1958	111,243	23,080	37,105	(14,025)	-12.61%	-11.13%	-14.76%	-11.36%	-13.55%	-11.15%	-9.22%	-8.52%	-7.14%	
1959	247,433	54,609	65,786	(11,177)	-4.52%	-7.03%	-8.02%	-10.90%	-9.09%	-10.99%	-9.63%	-8.31%	-7.78%	-6.68%
1960	110,397	26,450	29,450	(3,000)	-2.72%	-3.96%	-6.01%	-7.10%	-9.72%	-8.27%	-10.07%	-8.99%	-7.87%	-7.39%
1961	83,212	29,390	27,880	1,510	1.81%	-0.77%	-2.87%	-4.83%	-6.07%	-8.59%	-7.38%	-9.14%	-8.29%	-7.32%
1962	223,750	60,045	74,847	(14,802)	-6.62%	-4.33%	-3.90%	-4.13%	-5.35%	-6.20%	-8.18%	-7.23%	-8.70%	-8.04%
1963	123,649	36,193	37,982	(1,789)	-1.45%	-4.78%	-3.50%	-3.34%	-3.71%	-4.81%	-5.65%	-7.48%	-6.68%	-8.07%
1964	171,286	39,546	88,834	(49,288)	-28.78%	-17.32%	-12.70%	-10.69%	-9.46%	-8.18%	-8.64%	-8.85%	-10.15%	-9.27%
1965	239,572	59,859	91,231	(31,372)	-13.10%	-19.63%	-15.43%	-12.83%	-11.38%	-10.37%	-9.17%	-9.46%	-9.54%	-10.59%
1966	268,572	56,610	93,246	(36,636)	-13.64%	-13.38%	-17.26%	-14.83%	-13.04%	-11.93%	-11.09%	-9.98%	-10.17%	-10.17%
1967	236,404	41,635	69,071	(27,436)	-11.61%	-12.69%	-12.82%	-15.80%	-14.10%	-12.77%	-11.87%	-11.18%	-10.21%	-10.36%
1968	68,692	22,497	800	21,697	31.59%	-1.88%	-7.39%	-9.07%	-12.50%	-11.26%	-10.48%	-9.76%	-9.25%	-8.59%
1969	79,370	19,302	29,837	(10,535)	-13.27%	7.54%	-4.23%	-8.10%	-9.44%	-12.55%	-11.40%	-10.64%	-9.95%	-9.45%
1970	252,523	111,140	99,614	11,526	4.56%	0.30%	5.66%	-0.75%	-4.57%	-6.35%	-9.27%	-8.60%	-8.33%	-7.85%
1971	370,127	138,795	165,556	(26,761)	-7.23%	-2.45%	-3.67%	-0.53%	-3.13%	-5.34%	-6.57%	-8.82%	-8.32%	-8.13%
1972	267,968	84,801	98,589	(13,788)	-5.15%	-6.35%	-3.26%	-4.08%	-1.72%	-3.55%	-5.31%	-6.35%	-8.32%	-7.91%
1973	331,314	61,745	111,817	(50,072)	-15.11%	-10.66%	-9.35%	-6.47%	-6.89%	-4.96%	-5.94%	-7.04%	-7.73%	-9.30%
1974	224,263	131,581	36,855	94,726	42.24%	8.04%	3.75%	0.34%	1.08%	0.33%	1.68%	-0.04%	-1.78%	-2.94%
1975	100,106	204,026	127,550	76,476	76.40%	52.78%	18.47%	11.62%	6.23%	5.96%	5.02%	6.09%	3.93%	1.78%
1976	137,635	184,179	75,773	108,406	78.76%	77.77%	60.52%	28.93%	20.33%	13.20%	11.91%	10.77%	11.55%	8.91%
1977	575,616	333,652	213,369	120,283	20.90%	32.06%	37.52%	38.54%	25.55%	20.53%	15.41%	14.20%	13.27%	13.79%
1978	330,102	256,514	215,647	40,867	12.38%	17.79%	25.84%	30.26%	32.23%	22.99%	19.16%	14.98%	13.97%	13.16%
1979	130,511	270,156	73,349	196,807	150.80%	51.60%	34.54%	39.73%	42.61%	42.55%	32.11%	27.35%	22.16%	20.53%
1980	80,479	168,944	104,321	64,623	80.30%	123.91%	55.87%	37.84%	42.33%	44.85%	44.48%	34.14%	29.31%	24.00%
1981	1,347,903	308,088	81,854	226,234	16.78%	20.36%	31.28%	27.98%	26.33%	29.10%	30.85%	31.72%	26.96%	24.52%
1982	188,625	213,387	220,081	(6,694)	-3.55%	14.29%	17.57%	27.52%	25.12%	24.20%	26.89%	28.61%	29.59%	25.29%
1983	284,723	100,616	186,190	(85,574)	-30.06%	-19.49%	7.36%	10.44%	19.46%	18.47%	18.94%	21.62%	23.35%	24.59%
1984	128,508	122,917	98,108	24,809	19.31%	-14.70%	-11.21%	8.14%	11.00%	19.45%	18.51%	18.96%	21.53%	23.19%
1985	203,768	355,866	235,581	120,285	59.03%	43.67%	9.65%	6.56%	12.96%	15.38%	22.86%	21.57%	21.46%	23.77%
1986	334,582	1,323,661	229,431	1,094,230	327.04%	225.60%	185.85%	121.25%	100.60%	55.19%	55.98%	60.57%	55.31%	49.82%
1987	249,239	354,980	119,514	235,466	94.47%	227.76%	184.10%	160.99%	115.69%	99.50%	58.77%	59.39%	63.43%	58.29%
1988	193,583	497,454	146,452	351,002	181.32%	132.44%	216.19%	183.55%	164.53%	124.80%	109.51%	66.86%	67.22%	70.70%
1989	169,113	753,487	170,878	582,609	344.51%	257.41%	191.05%	239.12%	207.22%	188.33%	148.56%	132.19%	82.01%	81.97%
1990	143,770	1,000,396	177,284	823,112	572.52%	449.28%	346.86%	263.62%	283.08%	247.80%	227.16%	184.27%	165.58%	103.75%
1991	87,872	683,749	100,947	582,802	663.24%	606.93%	496.19%	393.64%	305.25%	311.44%	274.22%	252.53%	207.71%	187.62%
1992	711,569	103,508	311,292	(207,784)	-29.20%	46.91%	127.03%	160.09%	163.24%	152.22%	183.17%	171.09%	162.31%	140.46%
1993	231,185	404,483	281,046	123,437	53.39%	-8.95%	48.36%	112.53%	141.73%	146.72%	139.43%	169.03%	159.38%	152.05%
1994	459,243	375,526	373,995	1,531	0.33%	18.10%	-5.91%	33.56%	80.99%	105.71%	113.04%	110.98%	139.00%	133.15%
1995	416,978	204,081	423,835	(219,754)	-52.70%	-24.91%	-8.56%	-16.63%	14.70%	53.81%	75.95%	84.40%	85.35%	112.33%
1996	489,131	308,154	243,738	64,416	13.17%	-17.14%	-11.27%	-1.90%	-10.32%	14.38%	45.98%	64.62%	72.40%	74.15%
1997	781,592	997,904	466,262	531,642	68.02%	46.91%	22.30%	17.60%	21.08%	9.50%	27.58%	51.17%	65.38%	71.47%
1998	2,027,225	795,153	1,218,497	(423,344)	-20.88%	3.86%	5.24%	-1.27%	-1.09%	1.77%	-2.54%	8.70%	23.86%	33.69%
1999	930,274	1,274,243	438,875	835,368	89.80%	13.93%	25.24%	23.84%	16.97%	15.47%	17.12%	11.67%	21.00%	33.63%
2000	289,043	270,031	334,971	(64,940)	-22.47%	63.19%	10.69%	21.81%	20.88%	14.66%	13.44%	15.08%	10.11%	19.04%
2001	-	-	3,212	(3,212)	NA	-23.58%	62.92%	10.59%	21.73%	20.81%	14.60%	13.38%	15.03%	10.06%
2002	12,905	-	5,879	(5,879)	-45.56%	-70.45%	-24.52%	61.79%	10.37%	21.52%	20.62%	14.44%	13.24%	14.89%
2003	162,498	17,469	377,435	(359,966)	-221.52%	-208.57%	-210.41%	-93.44%	28.78%	-0.64%	12.12%	12.23%	6.93%	6.39%
2004	2,241		(1,739)	1,739	77.61%	-217.45%	-204.96%	-206.77%	-92.62%	28.86%	-0.59%	12.16%	12.26%	6.97%
2005	412,293	31,152	399,304	(368,152)	-89.29%	-88.39%	-125.88%	-124.13%	-124.67%	-91.06%	1.93%	-10.12%	3.10%	4.07%
2006	259,110	1,912	145,405	(143,492)	-55.38%	-76.21%	-75.69%	-104.03%	-103.15%	-103.52%	-82.94%	-5.25%	-12.99%	0.00%
2007	1,628,805 **	137,389	1,732,775	(1,595,386)	-97.95%	-92.11%	-91.60%	-91.44%	-100.01%	-99.73%	-99.86%	-91.77%	-46.09%	-37.16%
2008	1,099,496 **	191,085	2,265,061	(2,073,976)	-188.63%	-134.49%	-127.63%	-122.98%	-122.85%	-127.35%	-127.05%	-127.14%	-119.32%	-78.76%
2009	1,265,628	266,673	2,742,996	(2,476,323)	-195.66%	-192.39%	-153.88%	-147.87%	-142.70%	-142.59%	-145.25%	-144.98%	-145.05%	-138.14%
2010	1,555,659	106,822	2,089,498	(1,982,676)	-127.45%	-158.05%	-166.62%	-146.47%	-142.40%	-138.88%	-138.81%	-140.91%	-140.72%	-140.77%
2011	3,743,214	124,122	1,466,900	(1,342,778)	-35.87%	-62.76%	-88.38%	-102.76%	-101.92%	-100.66%	-100.19%	-100.15%	-102.09%	-102.02%
2012	2,168,890	312,346	1,707,632	(1,395,286)	-64.33%	-46.31%	-63.21%	-82.41%	-94.29%	-94.81%	-93.93%	-93.78%	-93.75%	-95.43%
2013	1,667,730.00	368,255	5,261,059	(4,892,804)	-293.38%	-163.90%	-100.67%	-105.23%	-116.24%	-123.16%	-120.03%	-118.78%	-117.90%	-117.87%
2014	180,243.00	78,812	1,201,242	(1,122,430)	-622.73%	-325.50%	-184.49%	-112.80%	-115.25%	-124.86%	-130.87%	-126.84%	-125.47%	-124.41%
2015	3,955,680.00	366,954	2,377,568	(2,010,614)	-50.83%	-75.75%	-138.29%	-118.17%	-91.88%	-96.05%	-104.72%	-110.62%	-109.42%	-108.62%
2016	811,686.00	40,463	179,993	(139,530)	-17.19%	-45.10%	-66.14%	-123.43%	-108.84%	-87.04%	-91.50%	-100.09%	-106.01%	-105.28%

** Includes retirements not posted until 2012 removal cost posted 2007and 2008

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Overhead Conductors & Devices
Account 356
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	66,825	51,664	18,824	32,840	49.14%									
1951	84,714	33,273	21,542	11,731	13.85%	29.41%								
1952	93,134	60,409	32,050	28,359	30.45%	22.54%	29.81%							
1953	348,127	168,272	43,587	124,685	35.82%	34.68%	31.33%	33.34%						
1954	130,287	177,443	55,960	121,483	93.24%	51.46%	48.03%	43.62%	44.13%					
1955	99,963	53,912	12,266	41,646	41.66%	70.85%	49.76%	47.08%	43.36%	43.83%				
1956	192,894	187,331	51,025	136,306	70.66%	60.76%	70.76%	54.99%	52.35%	48.91%	48.92%			
1957	175,856	120,104	39,717	80,387	45.71%	58.76%	55.12%	63.41%	53.27%	51.22%	48.41%	48.45%		
1958	139,213	67,143	33,274	33,869	24.33%	36.26%	49.33%	48.07%	56.04%	49.56%	48.05%	45.76%	45.93%	
1959	267,860	147,854	46,604	101,250	37.80%	33.19%	36.97%	45.35%	44.93%	51.18%	47.23%	46.15%	44.37%	44.57%
1960	155,789	106,235	26,450	79,785	51.21%	42.73%	38.18%	39.97%	46.33%	45.88%	51.19%	47.64%	46.64%	45.00%
1961	103,733	70,900	31,932	38,968	37.57%	45.76%	41.72%	38.08%	39.68%	45.45%	45.12%	50.07%	47.00%	46.09%
1962	256,965	133,567	75,527	58,040	22.59%	26.89%	34.23%	35.45%	33.77%	35.68%	40.90%	40.96%	45.43%	43.64%
1963	118,219	64,060	35,581	28,479	24.09%	23.06%	26.20%	32.34%	33.96%	32.67%	34.56%	39.49%	39.64%	43.89%
1964	183,379	71,468	53,360	18,108	9.87%	15.45%	18.73%	21.68%	27.31%	29.89%	29.26%	31.33%	36.09%	36.42%
1965	213,562	104,613	60,847	43,766	20.49%	15.59%	17.54%	19.22%	21.39%	25.90%	28.35%	27.96%	29.89%	34.24%
1966	295,258	151,009	83,481	67,528	22.87%	21.87%	18.69%	19.48%	20.23%	21.76%	25.22%	27.33%	27.09%	28.81%
1967	188,886	92,577	48,030	44,547	23.58%	23.15%	22.34%	19.74%	20.26%	20.73%	22.02%	25.02%	26.94%	26.75%
1968	92,881	46,343	655	45,688	49.19%	32.02%	27.34%	25.49%	22.55%	22.72%	22.69%	23.75%	26.41%	28.04%
1969	85,761	55,659	33,591	22,068	25.73%	37.93%	30.56%	27.13%	25.51%	22.81%	22.94%	22.87%	23.86%	26.38%
1970	266,406	151,399	81,777	69,622	26.13%	26.04%	30.87%	28.70%	26.85%	25.66%	23.48%	23.53%	23.38%	24.20%
1971	494,579	189,987	136,339	53,648	10.85%	16.20%	17.16%	20.33%	20.87%	21.29%	21.18%	20.05%	20.29%	20.56%
1972	264,526	93,323	81,191	12,132	4.59%	8.67%	13.20%	14.17%	16.87%	17.78%	18.67%	18.88%	18.08%	18.41%
1973	179,397	116,504	103,292	13,212	7.36%	5.71%	8.42%	12.33%	13.22%	15.64%	16.59%	17.59%	17.88%	17.24%
1974	196,988	146,743	29,911	116,832	59.31%	34.55%	22.18%	17.25%	18.93%	19.33%	21.08%	21.35%	21.57%	21.47%
1975	134,395	240,271	105,041	135,230	100.62%	76.06%	51.94%	35.78%	26.07%	26.08%	26.06%	27.31%	26.94%	26.40%
1976	106,926	145,175	62,401	82,774	77.41%	90.34%	76.39%	56.35%	40.83%	30.06%	29.42%	29.24%	30.26%	29.63%
1977	611,357	494,298	175,552	318,746	52.14%	55.90%	62.95%	62.27%	54.25%	45.46%	36.85%	35.58%	35.22%	35.75%
1978	343,077	364,284	152,650	211,634	61.69%	55.57%	57.77%	62.59%	62.12%	55.87%	48.49%	40.50%	39.03%	38.60%
1979	74,994	266,280	64,971	201,309	268.43%	98.77%	71.08%	71.67%	74.73%	72.66%	65.55%	57.12%	47.61%	45.47%
1980	93,579	84,918	85,311	(393)	-0.42%	119.19%	80.63%	65.12%	66.19%	69.58%	68.28%	62.01%	54.43%	45.81%
1981	1,689,484	247,910	30,473	217,437	12.87%	12.17%	22.52%	28.62%	33.73%	35.33%	38.21%	39.48%	37.80%	35.43%
1982	139,903	758,104	927,671	(169,567)	-121.20%	2.62%	2.47%	12.45%	19.67%	26.39%	28.17%	31.22%	32.85%	31.57%
1983	328,391	120,578	241,973	(121,395)	-36.97%	-62.13%	-3.41%	-3.28%	5.48%	12.70%	20.05%	21.86%	24.87%	26.69%
1984	170,389	27,135	124,969	(97,834)	-57.42%	-43.95%	-60.87%	-7.36%	-7.09%	1.18%	8.49%	16.22%	18.06%	21.07%
1985	191,637	238,772	160,619	78,153	40.78%	-5.44%	-20.43%	-37.41%	-3.70%	-3.58%	4.01%	10.53%	17.52%	19.22%
1986	623,823	561,713	222,874	338,839	54.32%	51.14%	32.37%	15.05%	1.94%	7.81%	7.58%	13.48%	18.01%	22.90%
1987	389,119	215,415	154,512	60,903	15.65%	39.46%	39.67%	27.64%	15.19%	4.83%	8.68%	8.44%	13.71%	17.78%
1988	243,975	325,768	163,428	162,340	66.54%	35.26%	44.72%	44.20%	33.50%	21.62%	12.05%	12.41%	12.10%	16.98%
1989	413,472	397,933	367,640	30,293	7.33%	29.30%	24.23%	35.46%	36.01%	28.18%	19.12%	11.27%	11.91%	11.64%
1990	162,316	196,148	197,065	(917)	-0.56%	5.10%	23.39%	20.90%	32.27%	33.08%	26.05%	17.85%	10.54%	11.45%
1991	86,293	485,828	83,157	402,671	466.63%	161.60%	65.26%	65.60%	50.59%	51.80%	50.80%	42.72%	32.69%	24.86%
1992	1,222,511	292,579	476,128	(183,549)	-15.01%	16.74%	14.83%	13.19%	19.30%	18.74%	25.80%	26.66%	22.57%	17.47%
1993	288,459	221,104	359,990	(138,886)	-48.15%	-21.34%	5.02%	4.51%	5.04%	11.25%	11.86%	19.58%	20.70%	17.19%
1994	411,416	118,412	395,767	(277,355)	-67.41%	-59.47%	-31.20%	-9.81%	-9.12%	-6.49%	-0.19%	1.72%	10.27%	11.72%
1995	917,726	335,547	518,325	(182,778)	-19.92%	-34.62%	-37.03%	-27.55%	-12.98%	-12.33%	-10.01%	-5.02%	-3.08%	4.45%
1996	1,007,759	367,203	675,241	(308,038)	-30.57%	-25.49%	-32.87%	-34.55%	-28.34%	-17.49%	-16.82%	-14.60%	-10.44%	-8.46%
1997	859,056	808,761	494,959	313,802	36.53%	0.31%	-6.36%	-14.22%	-17.03%	-16.50%	-7.81%	-7.57%	-6.42%	-3.25%
1998	1,165,034	498,655	801,651	(302,996)	-26.01%	0.53%	-9.80%	-12.15%	-17.37%	-19.28%	-18.39%	-11.36%	-11.08%	-9.91%
1999	701,725	877,112	529,973	347,139	49.47%	2.36%	13.13%	1.34%	-2.86%	-8.10%	-10.26%	-11.15%	-4.95%	-4.85%
2000	243,948	263,013	209,472	53,541	21.95%	42.37%	4.63%	13.86%	2.60%	-1.62%	-6.72%	-8.86%	-9.96%	-4.00%
2001	-	-	-	0	NA	21.95%	42.37%	4.63%	13.86%	2.60%	-1.62%	-6.72%	-8.86%	-9.96%
2002	5,128	-	5,403	(5,403)	-105.37%	-105.37%	19.33%	41.57%	4.36%	13.65%	2.46%	-1.73%	-6.82%	-8.95%
2003	220,143	30,977	234,143	(203,167)	-92.29%	-92.59%	-92.59%	-33.04%	16.41%	-4.75%	6.35%	-2.50%	-5.62%	-10.22%
2004	-	-	137,278	(137,278)	NA	-154.65%	-153.53%	-153.53%	-62.30%	4.68%	-10.62%	2.05%	-5.77%	-8.30%
2005	429,863	12,429	646,727	(634,298)	-147.56%	-179.49%	-149.96%	-149.61%	-149.61%	-103.06%	-36.20%	-31.91%	-15.69%	-18.92%
2006	288,470	-	309,266	(309,266)	-107.21%	-131.35%	-150.47%	-136.82%	-136.65%	-136.65%	-104.07%	-47.04%	-39.02%	-22.43%
2007	1,593,569 **	221,414	1,896,807	(1,675,393)	-105.13%	-105.45%	-113.28%	-119.22%	-116.88%	-116.85%	-116.85%	-104.68%	-73.62%	-61.69%
2008	1,389,790 **	341,108	1,389,569	(1,048,461)	-75.44%	-91.30%	-92.70%	-99.07%	-102.78%	-102.19%	-102.20%	-102.20%	-94.94%	-74.14%
2009	2,037,880	376,190	1,075,084	(698,894)	-34.30%	-50.98%	-68.17%	-70.29%	-76.07%	-78.47%	-78.98%	-79.00%	-79.00%	-75.03%
2010	4,956,065	130,964	958,324	(827,359)	-16.69%	-21.82%	-30.71%	-42.60%	-44.41%	-48.56%	-49.84%	-50.70%	-50.72%	-50.72%
2011	6,369,157	307,363	507,005	(199,642)	-3.13%	-9.07%	-12.92%	-18.81%	-27.22%	-28.61%	-31.60%	-32.41%	-33.17%	-33.19%
2012	733,460	38,688	330,222	(291,534)	-39.75%	-6.92%	-10.93%	-14.31%	-19.80%	-27.76%	-29.08%	-31.94%	-32.71%	-33.44%
2013	4,677,654.00	436,936	3,140,476	(2,703,540)	-57.80%	-55.35%	-27.12%	-24.03%	-25.15%	-28.61%	-34.22%	-35.17%	-37.32%	-37.93%
2014	591,007.00	103,338	1,190,684	(1,087,346)	-183.98%	-71.95%	-68.02%	-34.61%	-29.49%	-29.99%	-33.04%	-38.18%	-39.06%	-41.08%
2015	2,428,649.00	391,777	2,051,275	(1,659,498)	-68.33%	-90.97%	-70.81%	-68.11%	-40.15%	-34.26%	-34.27%	-36.73%	-41.13%	-41.89%
2016	435.00	62,207	197,930	(135,723)	-31200.69%	-73.91%	-95.45%	-72.57%	-69.71%	-41.06%	-34.95%	-34.89%	-37.32%	-41.68%

** Includes retirements not posted until 2012 removal cost posted 2007and 2008

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Underground Conduit
Account 357
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	11	-	11	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	-	0	NA	NA	NA							
1953	-	302	51	251	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	882	1,363	(481)	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1973	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1976	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1977	236	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1978	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1979	-	78,366	-	78,366	NA	NA	33205.93%	33205.93%	33205.93%	33205.93%	33205.93%	33205.93%	33205.93%	33205.93%
1980	46,030	123,082	7,690	115,392	250.69%	420.94%	420.94%	418.79%	418.79%	418.79%	418.79%	418.79%	418.79%	418.79%
1981	-	494,201	-	494,201	NA	1324.34%	1494.59%	1494.59%	1486.96%	1486.96%	1486.96%	1486.96%	1486.96%	1486.96%
1982	-	(68)	-	(68)	NA	NA	1324.19%	1494.44%	1494.44%	1486.82%	1486.82%	1486.82%	1486.82%	1486.82%
1983	117,534	118,874	3,186	115,688	98.43%	98.37%	518.85%	443.38%	491.29%	491.29%	490.59%	490.59%	490.59%	490.59%
1984	-	(7,504)	-	(7,504)	NA	92.04%	91.99%	512.46%	438.79%	486.71%	486.71%	486.00%	486.00%	486.00%
1985	9,155	(44,834)	3,000	(47,834)	-522.49%	-604.46%	47.64%	47.58%	437.67%	387.84%	433.21%	433.21%	432.62%	432.62%
1986	16,478	(80,601)	5,820	(86,421)	-524.46%	-523.76%	-553.03%	-18.21%	-18.26%	326.93%	308.38%	349.80%	349.80%	349.37%
1987	-	-	-	0	NA	-524.46%	-523.76%	-553.03%	-18.21%	-18.26%	326.93%	308.38%	349.80%	349.80%
1988	-	-	-	0	NA	NA	-524.46%	-523.76%	-553.03%	-18.21%	-18.26%	326.93%	308.38%	349.80%
1989	-	-	-	0	NA	NA	NA	-524.46%	-523.76%	-553.03%	-18.21%	-18.26%	326.93%	308.38%
1990	-	-	-	0	NA	NA	NA	NA	-524.46%	-523.76%	-553.03%	-18.21%	-18.26%	326.93%
1991	-	-	-	0	NA	NA	NA	NA	NA	-524.46%	-523.76%	-553.03%	-18.21%	-18.26%
1992	-	-	-	0	NA	NA	NA	NA	NA	NA	-524.46%	-523.76%	-553.03%	-18.21%
1993	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-524.46%	-523.76%	-553.03%
1994	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	-524.46%	-523.76%
1995	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-524.46%
1996	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1997	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1998	105,702	1	4,183	(4,182)	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%
1999	-	-	-	0	NA	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%
2000	-	-	-	0	NA	NA	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%
2001	-	-	-	0	NA	NA	NA	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%
2002	-	-	-	0	NA	NA	NA	NA	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%
2003	-	-	-	0	NA	NA	NA	NA	NA	-3.96%	-3.96%	-3.96%	-3.96%	-3.96%
2004	-	-	-	0	NA	NA	NA	NA	NA	NA	-3.96%	-3.96%	-3.96%	-3.96%
2005	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-3.96%	-3.96%	-3.96%
2006	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	-3.96%	-3.96%
2007	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-3.96%
2008	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	14,529	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	-	-	-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2015	-	-	16,825	(16,825)	NA	NA	NA	NA	NA	NA	-115.80%	-115.80%	-115.80%	-115.80%
2016	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-115.80%	-115.80%	-115.80%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Transmission Underground Conductor & Devices
Account 358
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	3	12	(9)	NA									
1951	-	-	-	0	NA	NA								
1952	-	1,588	401	1,187	NA	NA	NA							
1953	-	-	(2)	2	NA	NA	NA	NA						
1954	-	1	-	1	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	528	155	373	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	1,887	3,293	(1,406)	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	7	31	(24)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	235	-	31	(31)	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-23.40%
1973	-	-	-	0	NA	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%	-13.19%
1974	194	124	122	2	1.03%	1.03%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%
1975	-	-	-	0	NA	1.03%	1.03%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%	-6.76%
1976	-	256	-	256	NA	NA	132.99%	132.99%	52.91%	52.91%	52.91%	52.91%	52.91%	52.91%
1977	9,333	64	254	(190)	-2.04%	0.71%	0.71%	0.71%	0.71%	0.38%	0.38%	0.38%	0.38%	0.38%
1978	-	-	-	0	NA	-2.04%	0.71%	0.71%	0.71%	0.71%	0.38%	0.38%	0.38%	0.38%
1979	-	78,366	-	78,366	NA	NA	837.63%	840.37%	840.37%	823.28%	823.28%	803.14%	803.14%	803.14%
1980	29,359	129,405	4,905	124,500	424.06%	690.98%	690.98%	523.82%	524.48%	524.48%	521.87%	521.87%	518.65%	518.65%
1981	-	494,201	-	494,201	NA	2107.36%	2374.29%	2374.29%	1801.09%	1801.75%	1801.75%	1792.77%	1792.77%	1781.92%
1982	-	(71)	-	(71)	NA	NA	2107.12%	2374.05%	2374.05%	1800.90%	1801.57%	1801.57%	1792.58%	1792.58%
1983	109,217	118,874	3,186	115,688	105.92%	105.86%	558.35%	529.90%	586.45%	586.45%	549.32%	549.49%	549.49%	548.77%
1984	-	670,436	-	670,436	NA	719.78%	719.72%	1172.21%	1013.71%	1070.26%	1070.26%	1002.60%	1002.77%	1002.77%
1985	-	(54,902)	-	(54,902)	NA	NA	669.51%	669.45%	1121.94%	974.09%	1030.64%	1030.64%	965.48%	965.65%
1986	22,182	896,968	19,888	877,080	3954.02%	3706.51%	6728.94%	1223.98%	1223.93%	1600.04%	1385.27%	1434.02%	1434.02%	1355.22%
1987	-	-	-	0	NA	3954.02%	3706.51%	6728.94%	1223.98%	1223.93%	1600.04%	1385.27%	1434.02%	1434.02%
1988	-	-	-	0	NA	NA	3954.02%	3706.51%	6728.94%	1223.98%	1223.93%	1600.04%	1385.27%	1434.02%
1989	-	-	-	0	NA	NA	NA	3954.02%	3706.51%	6728.94%	1223.98%	1223.93%	1600.04%	1385.27%
1990	-	-	-	0	NA	NA	NA	NA	3954.02%	3706.51%	6728.94%	1223.98%	1223.93%	1600.04%
1991	-	-	-	0	NA	NA	NA	NA	NA	3954.02%	3706.51%	6728.94%	1223.98%	1223.93%
1992	-	-	-	0	NA	NA	NA	NA	NA	NA	3954.02%	3706.51%	6728.94%	1223.98%
1993	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	3954.02%	3706.51%	6728.94%
1994	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	3954.02%	3706.51%
1995	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	3954.02%
1996	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1997	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1998	640,008	72,657	99,359	(26,702)	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%
1999	-	-	-	0	NA	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%
2000	-	-	-	0	NA	NA	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%
2001	-	-	-	0	NA	NA	NA	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%
2002	-	-	-	0	NA	NA	NA	NA	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%
2003	-	-	-	0	NA	NA	NA	NA	NA	-4.17%	-4.17%	-4.17%	-4.17%	-4.17%
2004	-	-	-	0	NA	NA	NA	NA	NA	NA	-4.17%	-4.17%	-4.17%	-4.17%
2005	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-4.17%	-4.17%	-4.17%
2006	-	-	521	(521)	NA	NA	NA	NA	NA	NA	NA	NA	-4.25%	-4.25%
2007	-	-	(10,495)	10,495	NA	NA	NA	NA	NA	NA	NA	NA	NA	-2.61%
2008	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	393,655	-	58,795	(58,795)	-14.94%	-14.94%	-12.27%	-12.40%	-12.40%	-12.40%	-12.40%	-12.40%	-12.40%	-12.40%
2010	-	-	-	0	NA	-14.94%	-14.94%	-12.27%	-12.40%	-12.40%	-12.40%	-12.40%	-12.40%	-12.40%
2011	-	-	-	0	NA	NA	-14.94%	-14.94%	-12.27%	-12.40%	-12.40%	-12.40%	-12.40%	-12.40%
2012	-	-	-	0	NA	NA	NA	-14.94%	-14.94%	-12.27%	-12.40%	-12.40%	-12.40%	-12.40%
2013	0.00	0	-	0	NA	NA	NA	NA	-14.94%	-14.94%	-12.27%	-12.40%	-12.40%	-12.40%
2014	12,708.00	0	16,820	(16,820)	-132.36%	-132.36%	-132.36%	-132.36%	-132.36%	-18.61%	-18.61%	-16.03%	-16.15%	-16.15%
2015	0.00	0	-	0	NA	-132.36%	-132.36%	-132.36%	-132.36%	-132.36%	-18.61%	-18.61%	-16.03%	-16.15%
2016		0		0	NA	NA	-132.36%	-132.36%	-132.36%	-132.36%	-132.36%	-18.61%	-18.61%	-16.03%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Structures & Improvements
Account 361
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	4,668	1,727	805	922	19.75%									
1951	15,211	1,144	1,317	(173)	-1.14%	3.77%								
1952	4,097	334	1,128	(794)	-19.38%	-5.01%	-0.19%							
1953	4,717	1,146	987	159	3.37%	-7.20%	-3.36%	0.40%						
1954	8,964	392	520	(128)	-1.43%	0.23%	-4.29%	-2.84%	-0.04%					
1955	10,152	1,415	1,094	321	3.16%	1.01%	1.48%	-1.58%	-1.43%	0.64%				
1956	16,258	3,047	8,223	(5,176)	-31.84%	-18.38%	-14.09%	-12.03%	-12.71%	-9.75%	-7.60%			
1957	24,758	2,062	10,512	(8,450)	-34.13%	-33.22%	-26.00%	-22.34%	-20.47%	-20.40%	-16.92%	-14.99%		
1958	17,385	1,911	3,197	(1,286)	-7.40%	-23.10%	-25.53%	-21.28%	-18.99%	-17.71%	-17.79%	-15.29%	-13.75%	
1959	40,574	6,694	3,832	2,862	7.05%	2.72%	-8.31%	-12.17%	-10.75%	-10.04%	-9.53%	-9.84%	-8.91%	-8.00%
1960	33,009	4,751	12,367	(7,616)	-23.07%	-6.46%	-6.64%	-12.52%	-14.90%	-13.61%	-12.89%	-12.40%	-12.57%	-11.58%
1961	50,827	4,555	4,758	(203)	-0.40%	-9.33%	-3.98%	-4.40%	-8.82%	-10.87%	-10.13%	-9.74%	-9.44%	-9.64%
1962	43,137	2,904	20,442	(17,538)	-40.66%	-18.88%	-19.97%	-13.43%	-12.86%	-15.37%	-16.56%	-15.71%	-15.19%	-14.83%
1963	23,349	5,100	11,302	(6,202)	-26.56%	-35.71%	-20.41%	-20.99%	-15.03%	-14.40%	-16.49%	-17.49%	-16.68%	-16.18%
1964	44,172	2,864	16,446	(13,582)	-30.75%	-29.30%	-33.73%	-23.24%	-23.21%	-17.99%	-17.26%	-18.76%	-19.49%	-18.73%
1965	93,971	6,463	17,707	(11,244)	-11.97%	-17.97%	-19.21%	-23.73%	-19.09%	-19.55%	-16.27%	-15.82%	-17.04%	-17.66%
1966	44,516	14,397	24,947	(10,550)	-23.70%	-15.74%	-19.37%	-20.18%	-23.73%	-19.77%	-20.10%	-17.15%	-16.72%	-17.76%
1967	47,082	5,000	7,962	(2,962)	-6.29%	-14.75%	-13.34%	-16.69%	-17.60%	-20.96%	-17.95%	-18.39%	-15.94%	-15.60%
1968	100,728	24,978	10,696	14,282	14.18%	7.66%	0.40%	-3.66%	-7.28%	-8.55%	-12.04%	-10.72%	-11.57%	-10.12%
1969	45,723	34,090	15,429	18,661	40.81%	22.49%	15.49%	8.16%	2.47%	-1.43%	-2.90%	-6.58%	-5.94%	-7.02%
1970	79,325	28,343	14,637	13,706	17.28%	25.88%	20.66%	16.01%	10.44%	5.32%	1.82%	0.44%	-2.96%	-2.73%
1971	90,785	46,189	25,069	21,120	23.26%	20.47%	24.78%	21.41%	17.82%	13.29%	8.57%	5.39%	4.08%	0.93%
1972	79,179	12,811	11,132	1,679	2.12%	13.41%	14.64%	18.70%	17.55%	15.01%	11.48%	7.69%	4.97%	3.84%
1973	79,903	56	20,568	(20,512)	-25.67%	-11.84%	0.92%	4.86%	9.24%	10.29%	8.80%	6.24%	3.66%	1.50%
1974	98,153	10,602	18,608	(8,006)	-8.16%	-16.02%	-10.43%	-1.64%	1.87%	5.63%	7.13%	6.12%	4.12%	2.13%
1975	8,604	1,440	3,841	(2,401)	-27.91%	-9.75%	-16.56%	-11.00%	-2.28%	1.28%	5.03%	6.62%	5.65%	3.71%
1976	61,580	22,903	5,657	17,246	28.01%	21.15%	4.06%	-5.51%	-3.66%	2.18%	4.59%	7.64%	8.66%	7.64%
1977	35,275	4,109	15,065	(10,956)	-31.06%	6.49%	3.69%	-2.02%	-8.69%	-6.33%	-0.40%	2.23%	5.28%	6.60%
1978	13,789	1,635	2,687	(1,052)	-7.63%	-24.47%	4.73%	2.38%	-2.38%	-8.64%	-6.38%	-0.62%	1.98%	4.98%
1979	37,260	9,821	1,533	8,288	22.24%	14.17%	-4.31%	9.15%	7.11%	1.22%	-5.20%	-3.80%	1.07%	3.27%
1980	29,557	29,763	14,763	15,000	50.75%	34.85%	27.59%	9.73%	16.07%	14.04%	6.38%	-0.66%	-0.16%	3.82%
1981	55,983	(27,853)	28,361	(56,214)	-100.41%	-48.18%	-26.81%	-24.88%	-26.15%	-11.86%	-12.43%	-11.20%	-13.95%	-11.40%
1982	85,347	(838)	18,922	(19,760)	-23.15%	-53.76%	-35.68%	-25.31%	-24.21%	-25.15%	-14.88%	-15.23%	-13.60%	-15.50%
1983	66,282	4,622	19,315	(14,693)	-22.17%	-22.72%	-43.67%	-31.90%	-24.55%	-23.74%	-24.54%	-16.14%	-16.39%	-14.75%
1984	213,038	17,717	8,025	9,692	4.55%	-1.79%	-6.79%	-19.25%	-14.65%	-11.83%	-11.72%	-12.99%	-8.77%	-9.04%
1985	128,773	4,941	31,917	(26,976)	-20.95%	-5.06%	-7.84%	-10.48%	-19.65%	-16.05%	-13.74%	-13.60%	-14.53%	-10.93%
1986	106,345	23,029	5,751	17,278	16.25%	-4.12%	0.00%	-2.86%	-5.75%	-13.83%	-11.04%	-9.33%	-9.29%	-10.29%
1987	85,442	(9)	11,251	(11,260)	-13.18%	3.14%	-6.54%	-2.11%	-4.33%	-6.67%	-13.75%	-11.28%	-9.73%	-9.70%
1988	34,499	-	-	0	0.00%	-9.39%	2.66%	-5.90%	-1.98%	-4.09%	-6.35%	-13.14%	-10.80%	-9.33%
1989	59,494	5,347	1,552	3,795	6.38%	4.04%	-4.16%	3.43%	-4.14%	-1.19%	-3.19%	-5.38%	-11.75%	-9.61%
1990	158,940	10,747	44,037	(33,290)	-20.95%	-13.50%	-11.66%	-12.04%	-5.28%	-8.80%	-5.18%	-6.50%	-8.02%	-13.22%
1991	88,511	1,530	17,057	(15,527)	-17.54%	-19.73%	-14.67%	-13.19%	-13.18%	-7.31%	-9.97%	-6.43%	-7.54%	-8.84%
1992	6,597	2,833	36,184	(33,351)	-505.55%	-51.39%	-32.34%	-25.00%	-22.52%	-20.68%	-13.40%	-14.86%	-10.17%	-11.01%
1993	191,769	912	131,495	(130,583)	-68.09%	-82.64%	-62.56%	-47.72%	-41.35%	-38.71%	-35.22%	-27.74%	-26.72%	-20.52%
1994	59,748	(1,076)	51,894	(52,970)	-88.66%	-72.98%	-84.03%	-67.06%	-52.56%	-46.35%	-43.69%	-39.88%	-32.34%	-30.74%
1995	565,442	848	183,548	(182,700)	-32.31%	-37.70%	-44.83%	-48.52%	-45.52%	-41.87%	-39.33%	-38.17%	-36.46%	-32.33%
1996	145,351	16,460	798,066	(781,606)	-537.74%	-135.67%	-132.02%	-119.28%	-121.91%	-113.18%	-101.12%	-96.11%	-93.58%	-88.66%
1997	16,802	-	108,736	(108,736)	-647.16%	-549.08%	-147.48%	-143.01%	-128.34%	-130.86%	-121.53%	-108.56%	-103.27%	-100.59%
1998	72,654	(543)	9,690	(10,233)	-14.08%	-132.99%	-383.54%	-135.37%	-132.12%	-120.45%	-122.85%	-114.72%	-103.31%	-98.53%
1999	185,783	95	65,656	(65,561)	-35.29%	-29.33%	-67.04%	-229.71%	-116.51%	-114.92%	-107.66%	-109.77%	-103.65%	-94.84%
2000	130,869	1,531	117,556	(116,025)	-88.66%	-57.35%	-49.27%	-74.01%	-196.24%	-113.25%	-112.00%	-105.85%	-107.76%	-102.31%
2001	-	-	571	(571)	NA	-89.09%	-57.53%	-49.42%	-74.15%	-196.34%	-113.30%	-112.05%	-105.89%	-107.81%
2002	-	-	-	0	NA	NA	-89.09%	-57.53%	-49.42%	-74.15%	-196.34%	-113.30%	-112.05%	-105.89%
2003	1,313	-	379	(379)	-28.88%	-28.88%	-72.37%	-88.50%	-57.41%	-49.35%	-74.00%	-195.94%	-113.20%	-111.95%
2004	387,578	-	25,206	(25,206)	-6.50%	-6.58%	-6.58%	-6.73%	-27.36%	-29.44%	-28.01%	-41.10%	-117.86%	-85.74%
2005	26,913	-	-	0	0.00%	-6.08%	-6.15%	-6.15%	-6.29%	-26.01%	-28.36%	-27.07%	-39.75%	-114.58%
2006	36,406	-	3,203	(3,203)	-8.80%	-5.06%	-6.30%	-6.37%	-6.37%	-6.49%	-24.93%	-27.44%	-26.28%	-38.44%
2007	31	-	7,907	(7,907)	-25687.46%	-30.49%	-17.54%	-8.05%	-8.11%	-8.11%	-8.24%	-26.29%	-28.46%	-27.22%
2008	36,835	-	16,808	(16,808)	-45.63%	-67.04%	-38.10%	-27.87%	-10.89%	-10.94%	-10.94%	-11.06%	-27.44%	-29.25%
2009	407,177	532	571,354	(570,823)	-140.19%	-132.35%	-134.12%	-124.62%	-118.01%	-69.72%	-69.66%	-69.66%	-69.72%	-72.14%
2010	289,559	-	210,579	(210,579)	-72.72%	-112.15%	-108.81%	-109.88%	-105.11%	-101.56%	-70.45%	-70.41%	-70.41%	-70.46%
2011	6,315	-	6,899	(6,899)	-109.24%	-73.50%	-112.13%	-108.82%	-109.88%	-105.14%	-101.62%	-70.66%	-70.61%	-70.61%
2012	140,986	2,485	384,028	(381,543)	-270.62%	-263.71%	-137.12%	-138.60%	-134.71%	-135.61%	-130.57%	-126.85%	-91.83%	-91.77%
2013	90,141.00	72,376	39,055	33,321	36.97%	-150.66%	-149.56%	-107.34%	-121.66%	-118.78%	-119.59%	-115.58%	-112.58%	-83.66%
2014	12,249.00	46	40,402	(40,356)	-329.46%	-6.87%	-159.66%	-158.39%	-112.39%	-124.35%	-121.40%	-122.20%	-118.15%	-115.11%
2015	138,814.00	21,132	383,011	(361,879)	-260.69%	-266.27%	-152.95%	-196.36%	-194.94%	-142.75%	-141.79%	-138.63%	-139.33%	-135.23%
2016	0.00	2	166	(164)	NA	-260.81%	-266.38%	-153.01%	-196.40%	-194.98%	-142.77%	-141.80%	-138.65%	-139.35%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Station Equipment
Account 362
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	580,406	98,972	39,339	59,633	10.27%									
1951	486,275	68,206	36,237	31,969	6.57%	8.59%								
1952	408,213	106,440	27,175	79,265	19.42%	12.44%	11.59%							
1953	325,425	58,464	28,508	29,956	9.21%	14.89%	11.57%	11.15%						
1954	758,059	136,474	76,754	59,720	7.88%	8.28%	11.33%	10.16%	10.18%					
1955	497,109	114,311	56,995	57,316	11.53%	9.32%	9.30%	11.38%	10.43%	10.40%				
1956	413,464	189,776	41,358	148,418	35.90%	22.59%	15.91%	14.81%	15.60%	14.08%	13.44%			
1957	571,297	228,543	47,832	180,711	31.63%	33.42%	26.08%	19.92%	18.56%	18.68%	16.98%	16.01%		
1958	546,956	219,648	41,221	178,427	32.62%	32.12%	33.14%	27.84%	22.41%	21.03%	20.84%	19.11%	17.99%	
1959	955,632	286,162	69,482	216,680	22.67%	26.30%	27.77%	29.12%	26.19%	22.48%	21.42%	21.23%	19.80%	18.80%
1960	701,697	139,834	85,687	54,147	7.72%	16.34%	20.38%	22.70%	24.41%	22.67%	20.15%	19.40%	19.40%	18.30%
1961	611,125	203,606	48,278	155,328	25.42%	15.96%	18.79%	21.47%	23.19%	24.57%	23.06%	20.78%	20.08%	20.04%
1962	899,760	297,357	60,156	237,201	26.36%	25.98%	20.19%	20.94%	22.66%	23.85%	24.91%	23.63%	21.63%	20.98%
1963	726,973	291,149	46,228	244,921	33.69%	29.64%	28.48%	23.53%	23.32%	24.46%	25.28%	26.09%	24.87%	22.94%
1964	1,294,375	414,183	32,012	382,171	29.53%	31.02%	29.59%	28.87%	25.36%	24.87%	25.61%	26.15%	26.75%	25.70%
1965	935,518	399,358	66,813	332,545	35.55%	32.05%	32.45%	31.03%	30.27%	27.20%	26.50%	27.00%	27.36%	27.83%
1966	1,568,935	542,844	96,442	446,402	28.45%	31.10%	30.57%	31.07%	30.29%	29.79%	27.49%	26.90%	27.28%	27.56%
1967	855,704	297,807	58,020	239,787	28.02%	28.30%	30.32%	30.10%	30.58%	29.98%	29.57%	27.55%	27.01%	27.35%
1968	1,119,777	295,104	134,278	160,826	14.36%	20.28%	23.90%	26.33%	27.05%	27.79%	27.62%	27.45%	25.86%	25.54%
1969	2,116,252	342,102	126,493	215,609	10.19%	11.63%	15.06%	18.77%	21.15%	22.52%	23.47%	23.74%	23.84%	22.80%
1970	2,168,522	638,268	168,947	469,321	21.64%	15.99%	15.65%	17.34%	19.57%	21.27%	22.33%	23.10%	23.35%	23.45%
1971	1,947,078	501,021	179,219	321,802	16.53%	19.22%	16.15%	15.88%	17.15%	18.96%	20.41%	21.39%	22.09%	22.38%
1972	1,037,677	82,653	68,222	14,431	1.39%	11.27%	15.63%	14.05%	14.09%	15.38%	17.28%	18.73%	19.80%	20.53%
1973	718,039	374,958	108,811	266,147	37.07%	15.98%	16.27%	18.25%	16.12%	15.90%	16.94%	18.51%	19.79%	20.70%
1974	1,490,198	380,904	111,875	269,029	18.05%	24.24%	16.93%	16.78%	18.21%	16.42%	16.20%	17.09%	18.46%	19.60%
1975	1,738,144	614,293	162,415	451,878	26.00%	22.33%	25.01%	20.09%	19.09%	19.70%	17.91%	17.58%	18.26%	19.34%
1976	1,044,340	273,597	95,218	178,379	17.08%	22.65%	21.05%	23.35%	19.57%	18.83%	19.43%	17.83%	17.54%	18.17%
1977	1,647,038	562,726	253,421	309,305	18.78%	18.12%	21.21%	20.42%	22.22%	19.40%	18.82%	19.34%	17.95%	17.68%
1978	1,171,751	252,240	151,658	100,582	8.58%	14.54%	15.23%	18.57%	18.46%	20.17%	17.97%	17.71%	18.37%	17.22%
1979	2,167,258	604,763	189,746	415,017	19.15%	15.44%	16.54%	16.64%	18.73%	18.62%	19.95%	18.20%	17.95%	18.48%
1980	1,269,797	245,045	228,892	16,153	1.27%	12.54%	11.54%	13.44%	13.96%	16.28%	16.53%	17.84%	16.45%	16.46%
1981	847,117	390,650	114,912	275,738	32.55%	13.79%	16.50%	14.80%	15.72%	15.90%	17.67%	17.72%	18.87%	17.49%
1982	608,661	(168,164)	168,392	(336,556)	-55.29%	-4.18%	-1.64%	7.57%	7.77%	10.12%	10.95%	13.44%	14.01%	15.32%
1983	2,412,801	1,327,966	226,651	1,101,315	45.64%	25.31%	26.90%	20.56%	20.14%	18.55%	18.58%	18.44%	19.46%	19.32%
1984	1,795,506	(323,231)	196,978	(520,209)	-28.97%	13.81%	5.08%	9.19%	7.74%	10.45%	10.24%	11.42%	11.88%	13.55%
1985	2,110,292	633,564	533,137	100,427	4.76%	-10.75%	10.79%	4.98%	7.98%	7.04%	9.38%	9.31%	10.42%	10.88%
1986	1,118,393	304,196	228,745	75,451	6.75%	5.45%	-6.85%	10.18%	5.23%	7.83%	7.01%	9.14%	9.09%	10.15%
1987	1,754,370	1,094,746	236,977	857,769	48.89%	32.49%	20.74%	7.57%	17.57%	13.04%	14.59%	13.18%	14.09%	13.67%
1988	1,246,796	398,055	260,943	137,112	11.00%	33.15%	25.98%	18.79%	8.11%	16.78%	12.81%	14.22%	12.97%	13.84%
1989	1,549,267	(1,062,065)	255,034	(1,317,099)	-85.01%	-42.20%	-7.08%	-4.35%	-1.88%	-6.96%	3.63%	0.78%	2.78%	2.65%
1990	1,527,584	587,721	437,398	150,323	9.84%	-37.92%	-23.81%	-2.83%	-1.34%	0.04%	-4.65%	4.33%	1.76%	3.50%
1991	991,458	57,079	274,416	(217,337)	-21.92%	-2.66%	-34.02%	-23.46%	-5.51%	-3.83%	-2.07%	-6.07%	2.54%	0.21%
1992	2,093,341	176,967	371,143	(194,176)	-9.28%	-13.34%	-5.66%	-25.61%	-19.45%	-6.37%	-4.94%	-3.29%	-6.54%	1.05%
1993	2,850,572	11,209	484,649	(473,440)	-16.61%	-13.50%	-14.91%	-9.84%	-22.77%	-18.66%	-8.80%	-7.47%	-5.78%	-8.22%
1994	1,870,353	122,530	241,578	(119,048)	-6.37%	-12.55%	-11.54%	-12.86%	-9.15%	-19.95%	-16.77%	-8.47%	-7.34%	-5.84%
1995	5,159,212	287,613	945,396	(657,783)	-12.75%	-11.05%	-12.65%	-12.06%	-12.82%	-10.43%	-17.63%	-15.57%	-9.63%	-8.72%
1996	1,700,872	68,785	431,278	(362,493)	-21.31%	-14.87%	-13.05%	-13.93%	-13.21%	-13.80%	-11.57%	-17.99%	-16.08%	-10.59%
1997	2,402,522	144,366	365,288	(220,922)	-9.20%	-14.22%	-13.40%	-12.22%	-13.11%	-12.61%	-13.15%	-11.27%	-16.94%	-15.31%
1998	2,123,681	(4,117)	329,891	(334,008)	-15.73%	-12.26%	-14.73%	-13.83%	-12.78%	-13.46%	-12.98%	-13.44%	-11.72%	-16.82%
1999	2,140,164	499,705	335,508	164,197	7.67%	-3.98%	-5.86%	-9.00%	-10.43%	-9.94%	-10.98%	-10.80%	-11.32%	-9.91%
2000	5,933,577	48,117	1,176,442	(1,128,325)	-19.02%	-11.94%	-12.73%	-12.06%	-13.16%	-13.05%	-12.46%	-12.95%	-12.66%	-13.00%
2001	7,644	(26,011)	56,991	(83,002)	-1085.90%	-20.39%	-12.96%	-13.53%	-12.71%	-13.73%	-13.47%	-12.85%	-13.29%	-12.97%
2002	444,385	(890)	(890)	0	0.00%	-18.36%	-18.97%	-12.28%	-12.97%	-12.27%	-13.32%	-13.17%	-12.59%	-13.05%
2003	611,133	(209)	402,144	(402,353)	-65.84%	-38.12%	-45.65%	-23.06%	-15.86%	-15.84%	-14.67%	-15.41%	-14.74%	-14.04%
2004	1,918,984	153,620	389,606	(235,986)	-12.30%	-25.23%	-21.46%	-24.19%	-20.75%	-15.24%	-15.32%	-14.38%	-15.06%	-14.53%
2005	518,771	11,528	216,410	(204,882)	-39.49%	-18.08%	-27.66%	-24.14%	-26.46%	-21.78%	-16.33%	-16.24%	-15.19%	-15.77%
2006	2,176,283	-	257,631	(257,631)	-11.84%	-17.16%	-15.14%	-21.07%	-19.42%	-20.85%	-19.91%	-15.62%	-15.63%	-14.79%
2007	3,664,102	221,414	1,316,458	(1,095,043)	-29.89%	-23.16%	-24.49%	-21.67%	-24.70%	-23.53%	-24.40%	-22.31%	-18.62%	-18.31%
2008	3,455,741	341,108	719,927	(378,819)	-10.96%	-20.70%	-18.63%	-19.73%	-18.51%	-20.86%	-20.13%	-20.77%	-20.21%	-17.35%
2009	2,042,577	376,190	586,428	(210,238)	-10.29%	-10.71%	-18.38%	-17.12%	-18.10%	-17.29%	-19.36%	-18.78%	-19.33%	-19.24%
2010	3,222,362	130,964	2,165,848	(2,034,884)	-63.15%	-42.64%	-30.09%	-30.03%	-27.31%	-27.73%	-25.99%	-27.37%	-26.70%	-27.14%
2011	1,686,463	307,363	332,428	(25,066)	-1.49%	-41.96%	-32.66%	-25.45%	-26.61%	-24.63%	-25.09%	-23.78%	-25.11%	-24.54%
2012	2,226,359	184,444	917,217	(732,773)	-32.91%	-19.37%	-39.14%	-32.72%	-26.77%	-27.47%	-25.63%	-26.01%	-24.75%	-25.92%
2013	4,063,163.00	2,214,954	1,851,534	363,420	8.94%	-5.87%	-4.95%	-21.69%	-19.93%	-18.08%	-20.20%	-19.39%	-19.85%	-19.27%
2014	600,765.00	11,364	1,184,771	(1,173,407)	-195.32%	-17.37%	-22.39%	-18.28%	-30.53%	-27.55%	-24.23%	-25.22%	-23.96%	-24.30%
2015	3,618,822.00	153,570	1,513,650	(1,360,080)	-37.58%	-60.04%	-26.20%	-27.62%	-24.01%	-32.19%	-29.63%	-26.54%	-27.04%	-25.80%
2016	1,441,427.00	13,126	309,405	(296,279)	-20.55%	-32.73%	-49.99%	-25.36%	-26.77%	-23.64%	-31.19%	-28.94%	-26.16%	-26.68%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Poles, Towers & Fixtures
Account 364
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	362,810	138,721	157,389	(18,668)	-5.15%									
1951	390,340	167,709	171,357	(3,648)	-0.93%	-2.96%								
1952	469,069	193,928	203,469	(9,541)	-2.03%	-1.53%	-2.61%							
1953	471,325	201,761	211,768	(10,007)	-2.12%	-2.08%	-1.74%	-2.47%						
1954	546,267	194,142	227,302	(33,160)	-6.07%	-4.24%	-3.55%	-3.00%	-3.35%					
1955	453,354	166,190	207,220	(41,030)	-9.05%	-7.42%	-5.72%	-4.83%	-4.18%	-4.31%				
1956	560,734	211,800	270,036	(58,236)	-10.39%	-9.79%	-8.49%	-7.01%	-6.08%	-5.38%	-5.36%			
1957	665,054	225,191	321,788	(96,597)	-14.52%	-12.63%	-11.66%	-10.29%	-8.86%	-7.85%	-7.09%	-6.91%		
1958	585,324	184,524	316,709	(132,185)	-22.58%	-18.30%	-15.85%	-14.49%	-12.85%	-11.31%	-10.15%	-9.28%	-8.95%	
1959	599,575	205,710	308,655	(102,945)	-17.17%	-19.84%	-17.93%	-16.18%	-15.05%	-13.61%	-12.22%	-11.12%	-10.28%	-9.91%
1960	598,706	239,012	321,716	(82,704)	-13.81%	-15.49%	-17.82%	-16.92%	-15.71%	-14.83%	-13.64%	-12.43%	-11.44%	-10.68%
1961	567,584	143,220	315,362	(172,142)	-30.33%	-21.85%	-20.26%	-20.84%	-19.45%	-18.03%	-17.02%	-15.71%	-14.44%	-13.39%
1962	792,510	228,021	419,175	(191,154)	-24.12%	-26.71%	-22.77%	-21.46%	-21.67%	-20.42%	-19.13%	-18.18%	-16.95%	-15.75%
1963	690,456	189,208	371,385	(182,177)	-26.39%	-25.17%	-26.60%	-23.71%	-22.50%	-22.52%	-21.33%	-20.12%	-19.21%	-18.03%
1964	756,756	183,617	383,014	(199,397)	-26.35%	-26.37%	-25.57%	-26.53%	-24.30%	-23.23%	-23.15%	-22.06%	-20.93%	-20.07%
1965	804,409	169,470	424,453	(254,983)	-31.70%	-29.11%	-28.27%	-27.19%	-27.68%	-25.71%	-24.65%	-24.42%	-23.34%	-22.24%
1966	847,782	273,769	474,266	(200,497)	-23.65%	-27.57%	-27.19%	-27.01%	-26.42%	-26.92%	-25.37%	-24.50%	-24.32%	-23.37%
1967	805,477	233,692	536,116	(302,424)	-37.55%	-30.42%	-30.84%	-29.78%	-29.18%	-28.33%	-28.54%	-27.04%	-26.12%	-25.83%
1968	1,075,082	304,729	630,209	(325,480)	-30.27%	-33.39%	-30.36%	-30.67%	-29.91%	-29.42%	-28.69%	-28.84%	-27.54%	-26.72%
1969	1,031,876	327,687	692,795	(365,108)	-35.38%	-32.78%	-34.10%	-31.74%	-31.73%	-30.97%	-30.44%	-29.70%	-29.75%	-28.56%
1970	1,099,317	457,528	720,404	(262,876)	-23.91%	-29.47%	-29.74%	-31.31%	-29.97%	-30.22%	-29.76%	-29.43%	-28.90%	-28.99%
1971	789,082	316,327	579,299	(262,972)	-33.33%	-27.85%	-30.51%	-30.45%	-31.64%	-30.44%	-30.60%	-30.15%	-29.82%	-29.30%
1972	851,141	390,947	514,057	(123,110)	-14.46%	-23.54%	-23.69%	-26.89%	-27.64%	-29.05%	-28.35%	-28.72%	-28.49%	-28.33%
1973	786,997	357,350	442,644	(85,294)	-10.84%	-12.72%	-19.42%	-20.82%	-24.12%	-25.29%	-26.83%	-26.46%	-26.98%	-26.92%
1974	868,610	722,096	471,309	250,787	28.87%	10.00%	1.69%	-6.69%	-11.00%	-15.64%	-18.06%	-20.20%	-20.56%	-21.56%
1975	669,661	466,247	484,869	(18,622)	-2.78%	15.09%	6.32%	0.75%	-6.03%	-9.91%	-14.22%	-16.63%	-18.74%	-19.21%
1976	781,496	639,065	669,345	(30,280)	-3.87%	-3.37%	8.70%	3.75%	-0.16%	-5.68%	-9.11%	-13.05%	-15.38%	-17.42%
1977	855,685	608,648	808,910	(200,262)	-23.40%	-14.08%	-10.80%	0.05%	-2.11%	-4.30%	-8.38%	-10.93%	-14.19%	-16.16%
1978	806,509	598,244	957,979	(359,735)	-44.60%	-33.69%	-24.16%	-19.56%	-8.99%	-9.30%	-10.08%	-12.94%	-14.55%	-17.07%
1979	994,133	915,964	1,142,986	(227,022)	-22.84%	-32.59%	-29.63%	-23.77%	-20.35%	-11.76%	-11.63%	-12.00%	-14.27%	-15.52%
1980	997,429	1,077,699	1,134,786	(57,087)	-5.72%	-14.27%	-23.01%	-23.10%	-19.71%	-17.49%	-10.75%	-10.76%	-11.18%	-13.26%
1981	995,763	850,505	1,142,620	(292,115)	-29.34%	-17.52%	-19.29%	-24.67%	-24.44%	-21.48%	-19.43%	-13.41%	-13.15%	-13.28%
1982	859,241	750,335	904,844	(154,509)	-17.98%	-24.08%	-17.66%	-19.00%	-23.44%	-23.43%	-21.00%	-19.25%	-13.91%	-13.63%
1983	722,959	553,596	833,553	(279,957)	-38.72%	-27.46%	-28.18%	-21.92%	-22.12%	-25.49%	-25.20%	-22.83%	-21.08%	-16.01%
1984	811,245	634,607	990,768	(356,161)	-43.90%	-41.46%	-33.03%	-31.95%	-25.98%	-25.40%	-27.91%	-27.36%	-25.01%	-23.26%
1985	869,691	862,825	1,068,316	(205,491)	-23.63%	-33.41%	-35.01%	-30.53%	-30.25%	-25.59%	-25.16%	-27.38%	-26.95%	-24.87%
1986	761,199	721,560	1,019,111	(297,551)	-39.09%	-30.84%	-35.18%	-35.99%	-32.15%	-31.59%	-27.30%	-26.67%	-28.52%	-28.01%
1987	940,055	438,215	1,115,316	(677,101)	-72.03%	-57.29%	-45.90%	-45.42%	-44.24%	-39.70%	-37.97%	-33.34%	-32.03%	-33.19%
1988	782,576	593,197	928,440	(335,243)	-42.84%	-58.77%	-52.74%	-45.19%	-44.94%	-44.02%	-40.13%	-38.53%	-34.30%	-33.00%
1989	840,122	537,074	1,005,727	(468,653)	-55.78%	-49.54%	-57.79%	-53.51%	-47.31%	-46.76%	-45.74%	-42.12%	-40.44%	-36.41%
1990	954,826	382,133	1,115,170	(733,037)	-76.77%	-66.95%	-59.63%	-62.94%	-58.70%	-52.77%	-51.57%	-50.18%	-46.51%	-44.51%
1991	952,268	316,848	1,178,838	(861,990)	-90.52%	-83.64%	-75.12%	-67.96%	-68.82%	-64.49%	-58.67%	-56.93%	-55.21%	-51.44%
1992	920,840	273,420	1,548,982	(1,275,562)	-138.52%	-114.12%	-101.51%	-91.04%	-82.56%	-80.72%	-75.57%	-69.14%	-66.53%	-64.18%
1993	886,974	273,526	1,457,836	(1,184,310)	-133.52%	-136.07%	-120.35%	-109.15%	-99.31%	-91.03%	-88.18%	-82.87%	-76.36%	-73.34%
1994	735,765	273,404	1,202,388	(928,984)	-126.26%	-130.23%	-133.23%	-121.60%	-111.98%	-103.06%	-95.30%	-92.18%	-86.98%	-80.61%
1995	1,053,000	332,152	1,386,330	(1,054,178)	-100.11%	-110.87%	-118.38%	-123.54%	-116.62%	-109.71%	-102.57%	-96.01%	-93.21%	-88.55%
1996	1,330,016	450,572	1,468,879	(1,018,307)	-76.56%	-86.97%	-96.24%	-104.49%	-110.85%	-107.56%	-103.26%	-98.06%	-92.95%	-90.86%
1997	1,267,093	382,023	1,529,412	(1,147,389)	-90.55%	-83.39%	-88.21%	-94.60%	-101.14%	-106.70%	-104.54%	-101.27%	-97.00%	-92.64%
1998	1,659,671	538,137	1,847,881	(1,309,744)	-78.92%	-83.95%	-81.64%	-85.31%	-90.29%	-95.82%	-100.83%	-99.71%	-97.47%	-94.17%
1999	1,909,168	1,175,239	2,373,833	(1,198,594)	-62.78%	-70.28%	-75.60%	-75.80%	-79.35%	-83.69%	-88.69%	-93.39%	-93.13%	-91.79%
2000	1,918,722	545,808	2,086,404	(1,540,596)	-80.29%	-71.56%	-73.78%	-76.93%	-76.87%	-79.55%	-83.03%	-87.19%	-91.24%	-91.18%
2001	1,332,653	172,764	1,799,297	(1,626,533)	-122.05%	-97.41%	-84.60%	-83.22%	-84.36%	-83.26%	-84.96%	-87.67%	-91.03%	-94.39%
2002	739,364	55,756.79	795,800	(740,044)	-100.09%	-114.22%	-97.91%	-86.54%	-84.87%	-85.68%	-84.49%	-85.96%	-88.44%	-91.55%
2003	640,353	-	463,689	(463,689)	-72.41%	-87.24%	-104.35%	-94.38%	-85.16%	-83.89%	-84.78%	-83.77%	-85.22%	-87.62%
2004	923,703	-	282,566	(282,566)	-30.59%	-47.71%	-64.53%	-85.61%	-83.77%	-78.40%	-78.50%	-79.97%	-79.58%	-81.27%
2005	876,456	-	488,383	(488,383)	-55.72%	-42.83%	-50.59%	-62.10%	-79.80%	-79.95%	-76.02%	-76.50%	-78.08%	-77.92%
2006	1,328,528	5,788.00	647,767	(641,979)	-48.32%	-51.26%	-45.16%	-49.79%	-58.04%	-72.64%	-74.54%	-72.21%	-73.20%	-74.94%
2007	832,466	-	4,027,184.12	(4,027,184)	-483.77%	-216.07%	-169.80%	-137.34%	-128.30%	-124.40%	-123.93%	-114.18%	-104.84%	-101.30%
2008	984,341	-	1,819,603.36	(1,819,603)	-184.85%	-321.82%	-206.30%	-173.48%	-146.79%	-138.27%	-133.80%	-131.76%	-121.45%	-111.70%
2009	661,009	-	1,827,129.46	(1,827,129)	-276.42%	-221.64%	-309.70%	-218.47%	-188.01%	-162.08%	-152.89%	-147.30%	-143.25%	-131.45%
2010	912,450	-	1,538,628.63	(1,538,629)	-168.63%	-213.91%	-202.73%	-271.74%	-208.84%	-184.85%	-162.99%	-154.89%	-149.76%	-145.76%
2011	1,690,352	-	2,664,541.08	(2,664,541)	-157.63%	-161.49%	-184.76%	-184.78%	-233.77%	-195.33%	-178.54%	-161.89%	-155.42%	-151.15%
2012	937,758	1,459,534	2,842,830	(1,383,296)	-147.51%	-154.02%	-157.78%	-176.45%	-178.04%	-220.33%	-189.23%	-175.00%	-160.42%	-154.66%
2013	906,698.00	1,067,618	2,798,945	(1,731,327)	-190.95%	-168.86%	-163.49%	-164.55%	-179.02%	-179.96%	-216.48%	-189.42%	-176.58%	-163.17%
2014	1,114,666.00	1,113,335	2,774,147	(1,660,812)	-149.00%	-167.81%	-161.38%	-160.02%	-161.43%	-173.64%	-175.17%	-207.13%	-184.61%	-173.58%
2015	1,455,614.00	663,949	3,394,032	(2,730,083)	-187.56%	-170.83%	-176.08%	-170.01%	-166.58%	-166.85%	-176.28%	-177.26%	-204.13%	-185.00%
2016	600,771.00	679,237	5,983,222	(5,303,985)	-882.86%	-390.69%	-305.73%	-280.21%	-255.40%	-230.75%	-223.31%	-227.55%	-223.02%	-244.52%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Overhead Conductors & Devices
Account 365
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	311,231	188,324	74,502	113,822	36.57%									
1951	321,364	190,799	81,674	109,125	33.96%	35.24%								
1952	390,977	245,915	97,882	148,033	37.86%	36.10%	36.24%							
1953	376,791	295,560	105,941	189,619	50.32%	43.98%	41.02%	40.03%						
1954	396,215	338,733	110,064	228,669	57.71%	54.11%	48.65%	45.47%	43.93%					
1955	425,512	351,830	93,288	258,542	60.76%	59.29%	56.47%	51.89%	48.88%	47.15%				
1956	491,978	369,139	118,549	250,590	50.94%	55.49%	56.16%	54.86%	51.67%	49.30%	47.84%			
1957	684,494	393,508	138,560	254,948	37.25%	42.97%	47.70%	49.68%	49.78%	48.10%	46.63%	45.71%		
1958	615,131	369,685	136,084	233,601	37.98%	37.59%	41.26%	45.00%	46.93%	47.35%	46.26%	45.19%	44.52%	
1959	563,107	397,873	137,600	260,273	46.22%	41.92%	40.20%	42.44%	45.25%	46.80%	47.18%	46.25%	45.33%	44.73%
1960	605,124	371,815	150,747	221,068	36.53%	41.20%	40.09%	39.30%	41.23%	43.69%	45.16%	45.63%	44.96%	44.23%
1961	612,283	344,925	155,362	189,563	30.96%	33.73%	37.68%	37.76%	37.64%	39.47%	41.74%	43.18%	43.74%	43.30%
1962	913,571	479,590	221,981	257,609	28.20%	29.31%	31.36%	34.46%	35.12%	35.48%	37.18%	39.22%	40.60%	41.25%
1963	777,890	371,578	195,240	176,338	22.67%	25.66%	27.07%	29.03%	31.82%	32.75%	33.39%	35.03%	36.96%	38.31%
1964	790,038	374,700	205,126	169,574	21.46%	22.06%	24.32%	25.63%	27.42%	29.90%	30.92%	31.70%	33.26%	35.07%
1965	1,086,662	442,064	273,496	168,568	15.51%	18.02%	19.38%	21.64%	23.00%	24.71%	26.98%	28.11%	29.05%	30.56%
1966	1,181,692	526,799	229,649	297,150	25.15%	20.53%	20.77%	21.16%	22.51%	23.48%	24.80%	26.65%	27.62%	28.46%
1967	1,131,512	462,766	264,397	198,369	17.53%	21.42%	19.53%	19.90%	20.33%	21.55%	22.44%	23.64%	25.30%	26.24%
1968	1,364,210	588,198	306,146	282,052	20.68%	19.25%	21.14%	19.86%	20.09%	20.41%	21.39%	22.13%	23.16%	24.60%
1969	1,533,663	608,005	330,668	277,337	18.08%	19.30%	18.81%	20.24%	19.43%	19.65%	19.95%	20.81%	21.47%	22.38%
1970	1,540,399	676,390	344,155	332,235	21.57%	19.83%	20.09%	19.57%	20.55%	19.85%	20.00%	20.22%	20.92%	21.49%
1971	1,115,794	432,839	241,627	191,212	17.14%	19.71%	19.11%	19.50%	19.16%	20.06%	19.51%	19.67%	19.89%	20.55%
1972	1,148,405	511,359	277,138	234,221	20.40%	18.79%	19.91%	19.39%	19.65%	19.34%	20.10%	19.61%	19.75%	19.94%
1973	1,094,044	551,011	272,272	278,739	25.48%	22.87%	20.97%	21.16%	20.42%	20.47%	20.10%	20.69%	20.18%	20.27%
1974	1,186,378	982,553	296,225	686,328	57.85%	42.32%	34.98%	30.60%	28.31%	26.25%	25.41%	24.52%	24.59%	23.79%
1975	1,001,179	727,041	334,658	392,383	39.19%	49.31%	41.37%	35.93%	32.15%	29.85%	27.76%	26.79%	25.85%	25.78%
1976	1,139,105	746,008	404,527	341,481	29.98%	34.29%	42.69%	38.43%	34.71%	31.78%	29.87%	28.01%	27.11%	26.23%
1977	1,052,882	727,239	531,781	195,458	18.56%	24.50%	29.10%	36.89%	34.61%	32.14%	29.98%	28.58%	27.09%	26.38%
1978	1,036,168	617,860	529,372	88,488	8.54%	13.59%	19.37%	24.07%	31.47%	30.46%	28.95%	27.45%	26.57%	25.47%
1979	1,217,414	1,089,903	581,581	508,322	41.75%	26.48%	23.96%	25.50%	28.02%	33.35%	32.24%	30.71%	29.19%	28.17%
1980	1,206,570	1,215,879	812,525	403,354	33.43%	37.61%	28.91%	26.49%	27.20%	29.00%	33.37%	32.40%	31.03%	29.65%
1981	1,348,144	813,255	1,023,266	(210,011)	-15.58%	7.57%	18.60%	16.43%	16.82%	18.96%	21.49%	26.18%	26.11%	25.54%
1982	1,184,273	891,439	861,742	29,697	2.51%	-7.12%	5.97%	14.76%	13.68%	14.41%	16.58%	19.04%	23.48%	23.67%
1983	983,821	705,168	719,722	(14,554)	-1.48%	0.70%	-5.54%	4.41%	12.07%	11.54%	12.46%	14.64%	17.06%	21.32%
1984	1,142,514	1,223,869	923,090	300,779	26.33%	13.46%	9.54%	2.27%	8.68%	14.37%	13.62%	14.19%	15.93%	17.99%
1985	1,287,338	1,219,214	1,018,726	200,488	15.57%	20.63%	14.26%	11.23%	5.15%	9.92%	14.55%	13.89%	14.36%	15.89%
1986	1,006,210	1,104,204	886,423	217,781	21.64%	18.24%	20.93%	15.94%	13.10%	7.54%	11.37%	15.31%	14.64%	15.00%
1987	1,271,033	874,009	991,850	(117,841)	-9.27%	4.39%	8.43%	12.77%	10.31%	8.96%	4.94%	8.59%	12.38%	12.04%
1988	1,102,260	1,250,157	893,030	357,127	32.40%	10.08%	13.52%	14.09%	16.50%	13.89%	12.20%	8.19%	11.08%	14.26%
1989	1,364,652	814,344	1,001,622	(187,278)	-13.72%	6.89%	1.39%	5.69%	7.80%	10.75%	9.27%	8.42%	5.39%	8.23%
1990	1,518,591	763,122	968,484	(205,362)	-13.52%	-13.62%	-0.89%	-2.92%	1.03%	3.51%	6.51%	5.70%	5.35%	3.04%
1991	1,373,240	516,756	1,100,444	(583,688)	-42.50%	-27.29%	-22.94%	-11.55%	-11.12%	-6.80%	-3.57%	-0.18%	-0.29%	-0.02%
1992	2,644,759	478,960	1,670,950	(1,191,990)	-45.07%	-44.19%	-35.78%	-31.42%	-22.63%	-20.80%	-16.65%	-13.06%	-9.52%	-8.94%
1993	2,405,576	323,269	1,490,514	(1,167,245)	-48.52%	-46.71%	-45.81%	-39.64%	-35.84%	-28.61%	-26.51%	-22.69%	-19.16%	-15.73%
1994	1,906,308	382,459	1,138,160	(755,701)	-39.64%	-44.60%	-44.78%	-44.40%	-39.64%	-36.49%	-30.32%	-28.35%	-24.90%	-21.62%
1995	1,999,112	736,309	1,327,071	(590,762)	-29.55%	-34.48%	-39.83%	-41.38%	-41.53%	-37.94%	-35.44%	-30.21%	-28.51%	-25.46%
1996	2,458,589	603,448	1,311,527	(708,079)	-28.80%	-29.14%	-32.28%	-36.74%	-38.67%	-39.08%	-36.37%	-34.40%	-30.01%	-28.55%
1997	2,231,917	560,259	1,303,589	(743,330)	-33.30%	-30.94%	-30.53%	-32.55%	-36.04%	-37.79%	-38.22%	-35.95%	-34.26%	-30.39%
1998	2,976,280	751,165	1,692,351	(941,186)	-31.62%	-32.34%	-31.21%	-30.86%	-32.31%	-35.10%	-36.69%	-37.13%	-35.29%	-33.88%
1999	3,519,349	1,165,780	2,105,564	(939,784)	-26.70%	-28.96%	-30.07%	-29.79%	-29.75%	-31.00%	-33.41%	-34.94%	-35.43%	-33.98%
2000	3,583,144	599,171	1,853,315	(1,254,144)	-35.00%	-30.89%	-31.11%	-31.50%	-31.05%	-30.88%	-31.77%	-33.68%	-34.95%	-35.36%
2001	2,245,747	186,080	1,521,713	(1,335,634)	-59.47%	-44.43%	-37.76%	-36.28%	-35.82%	-34.81%	-34.25%	-34.74%	-36.17%	-37.07%
2002	267,023	$6,396.46	1,177,045	(1,170,649)	-438.41%	-99.74%	-61.69%	-48.88%	-44.80%	-43.07%	-41.04%	-39.85%	-39.83%	-40.72%
2003	1,321,734	$70,481.49	8,623	61,859	4.68%	-69.79%	-63.75%	-49.86%	-42.41%	-40.10%	-39.16%	-37.79%	-36.99%	-37.22%
2004	2,180,897	$515,567.28	372,909	142,658	6.54%	5.84%	-25.63%	-38.26%	-37.05%	-34.27%	-33.78%	-33.72%	-33.14%	-32.83%
2005	3,285,767	$490,005.10	1,348,786	(858,781)	-26.14%	-13.10%	-9.64%	-25.87%	-33.98%	-34.26%	-32.64%	-32.49%	-32.57%	-32.18%
2006	3,588,071	$578,188.59	1,216,234	(638,045)	-17.78%	-21.78%	-14.96%	-12.45%	-23.14%	-29.47%	-30.67%	-29.97%	-30.19%	-30.46%
2007	6,258,148	681,882.43	3,036,373.43	(2,354,491)	-37.62%	-30.39%	-29.33%	-24.22%	-21.92%	-28.50%	-32.14%	-32.59%	-31.80%	-31.78%
2008	6,843,323	1,074,260.89	1,662,865.20	(588,604)	-8.60%	-22.46%	-21.46%	-22.23%	-19.40%	-18.04%	-22.77%	-25.94%	-27.04%	-27.00%
2009	4,581,574	435,034.28	1,876,982.35	(1,441,948)	-31.47%	-17.77%	-24.80%	-23.61%	-23.95%	-21.46%	-20.23%	-24.18%	-26.77%	-27.63%
2010	5,179,417	571,162.57	1,512,856.92	(941,694)	-18.18%	-24.42%	-17.90%	-23.30%	-22.55%	-22.95%	-20.93%	-19.91%	-23.25%	-25.52%
2011	9,863,938	778,236.49	2,802,065.45	(2,023,829)	-20.52%	-19.71%	-22.46%	-18.88%	-22.46%	-22.00%	-22.34%	-20.83%	-20.05%	-22.63%
2012	7,598,664	593,007	3,088,170	(2,495,162)	-32.84%	-25.88%	-24.12%	-25.36%	-21.99%	-24.42%	-23.87%	-24.03%	-22.68%	-21.97%
2013	7,305,864.41	1,637,565	3,265,206	(1,627,641)	-22.28%	-27.66%	-24.82%	-23.67%	-24.70%	-22.04%	-24.09%	-23.65%	-23.80%	-22.63%
2014	8,867,420.47	2,002,597	5,200,285	(3,197,688)	-36.06%	-29.84%	-30.79%	-27.78%	-26.50%	-27.02%	-24.52%	-25.97%	-25.48%	-25.51%
2015	6,966,420.18	300,048	3,003,725	(2,703,677)	-38.81%	-37.27%	-32.54%	-32.61%	-29.67%	-28.37%	-28.66%	-26.26%	-27.38%	-26.86%
2016	2,840,964.44	218,763	5,047,648	(4,828,885)	-169.97%	-76.81%	-57.46%	-47.57%	-44.23%	-38.85%	-36.65%	-36.20%	-33.06%	-33.49%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Underground Conduit
Account 366
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	12,207	1,647	1,354	293	2.40%									
1951	10,409	870	683	187	1.80%	2.12%								
1952	19,407	1,945	2,080	(135)	-0.70%	0.17%	0.82%							
1953	8,226	3,019	1,514	1,505	18.30%	4.96%	4.09%	3.68%						
1954	5,417	640	499	141	2.60%	12.06%	4.57%	3.91%	3.58%					
1955	6,073	492	1,779	(1,287)	-21.19%	-9.97%	1.82%	0.57%	0.83%	1.14%				
1956	27,113	3,770	6,185	(2,415)	-8.91%	-11.16%	-9.22%	-4.39%	-3.31%	-2.61%	-1.93%			
1957	22,217	6,215	4,801	1,414	6.36%	-2.03%	-4.13%	-3.53%	-0.93%	-0.88%	-0.60%	-0.27%		
1958	33,073	3,984	5,085	(1,101)	-3.33%	0.57%	-2.55%	-3.83%	-3.46%	-1.71%	-1.55%	-1.28%	-0.97%	
1959	46,508	2,679	7,852	(5,173)	-11.12%	-7.88%	-4.77%	-5.64%	-6.34%	-6.00%	-4.65%	-4.20%	-3.85%	-3.45%
1960	9,760	2,516	2,278	238	2.44%	-8.77%	-6.76%	-4.14%	-5.07%	-5.75%	-5.45%	-4.22%	-3.83%	-3.52%
1961	18,699	2,882	2,991	(109)	-0.58%	0.45%	-6.73%	-5.69%	-3.63%	-4.54%	-5.16%	-4.91%	-3.83%	-3.52%
1962	71,602	4,325	9,478	(5,153)	-7.20%	-5.83%	-5.02%	-6.96%	-6.29%	-4.90%	-5.37%	-5.78%	-5.59%	-4.80%
1963	28,679	2,092	10,094	(8,002)	-27.90%	-13.12%	-11.15%	-10.12%	-10.38%	-9.26%	-7.76%	-7.88%	-8.19%	-7.97%
1964	64,509	2,062	10,198	(8,136)	-12.61%	-17.32%	-12.92%	-11.66%	-10.95%	-10.98%	-10.06%	-8.82%	-8.83%	-9.06%
1965	107,616	5,297	25,282	(19,985)	-18.57%	-16.34%	-17.99%	-15.15%	-14.22%	-13.68%	-13.33%	-12.46%	-11.43%	-11.27%
1966	97,080	3,169	12,141	(8,972)	-9.24%	-14.15%	-13.78%	-15.14%	-13.60%	-12.97%	-12.59%	-12.44%	-11.81%	-11.00%
1967	100,758	2,186	14,937	(12,751)	-12.66%	-10.98%	-13.65%	-13.47%	-14.51%	-13.40%	-12.91%	-12.61%	-12.48%	-11.96%
1968	153,763	1,264	16,202	(14,938)	-9.71%	-10.88%	-10.43%	-12.34%	-12.37%	-13.18%	-12.49%	-12.14%	-11.93%	-11.87%
1969	47,362	2,231	11,081	(8,850)	-18.69%	-11.83%	-12.10%	-11.41%	-12.93%	-12.89%	-13.61%	-12.93%	-12.59%	-12.38%
1970	115,293	27,677	12,374	15,303	13.27%	3.97%	-2.68%	-5.09%	-5.87%	-8.07%	-8.50%	-9.28%	-9.09%	-8.89%
1971	28,305	107,839	4,197	103,642	366.16%	82.83%	57.65%	27.60%	18.50%	13.53%	8.22%	6.34%	5.02%	3.95%
1972	94,916	58,557	6,053	52,504	55.32%	126.72%	71.88%	56.88%	33.59%	24.96%	19.76%	14.22%	12.08%	10.71%
1973	74,941	4,053	4,667	(614)	-0.82%	30.55%	78.49%	54.50%	44.89%	28.58%	21.82%	17.59%	12.85%	10.99%
1974	62,399	100,932	5,912	95,020	152.28%	68.74%	63.25%	96.16%	70.73%	60.73%	41.95%	33.84%	28.44%	22.71%
1975	47,348	59,204	6,160	53,044	112.03%	134.91%	79.84%	71.51%	98.60%	75.35%	65.89%	47.27%	38.94%	33.25%
1976	65,310	7,541	13,377	(5,836)	-8.94%	41.90%	81.25%	56.65%	56.28%	79.78%	64.09%	56.77%	41.95%	34.99%
1977	94,788	(147,647)	12,009	(159,656)	-168.43%	-103.37%	-54.21%	-6.46%	-5.23%	7.84%	29.51%	26.30%	22.92%	16.52%
1978	81,337	93,985	27,880	66,105	81.27%	-53.12%	-41.17%	-16.05%	13.86%	11.28%	19.30%	37.17%	33.03%	29.59%
1979	51,770	252,268	17,178	235,090	454.10%	226.28%	62.11%	46.28%	55.42%	70.42%	59.25%	58.60%	73.08%	63.46%
1980	87,626	263,113	35,992	227,121	259.19%	331.58%	239.35%	116.84%	95.27%	97.12%	104.14%	90.23%	85.21%	96.76%
1981	153,243	285,943	48,113	237,830	155.20%	193.03%	239.22%	204.87%	129.38%	112.47%	112.43%	116.29%	104.08%	98.39%
1982	70,298	68,384	67,679	705	1.00%	106.71%	149.65%	193.08%	172.61%	112.64%	99.50%	100.41%	104.94%	94.90%
1983	87,920	136,677	48,879	87,798	99.86%	55.94%	104.77%	138.68%	174.90%	160.59%	110.85%	99.55%	100.35%	104.39%
1984	89,831	58,144	37,340	20,804	23.16%	61.10%	44.07%	86.50%	117.45%	149.69%	140.74%	99.86%	90.77%	91.99%
1985	125,149	428,363	43,028	385,335	307.90%	188.92%	163.07%	132.54%	139.14%	156.27%	179.43%	168.74%	130.78%	120.72%
1986	98,818	446,485	51,961	394,524	399.24%	348.20%	255.15%	221.17%	188.38%	180.24%	189.95%	207.83%	195.67%	158.98%
1987	156,712	774,890	102,067	672,823	429.34%	417.70%	381.60%	313.17%	279.58%	248.44%	230.16%	233.09%	245.51%	232.19%
1988	136,359	472,096	57,192	414,904	304.27%	371.15%	378.23%	361.21%	311.17%	284.43%	258.39%	241.17%	242.74%	253.08%
1989	230,601	342,776	134,559	208,217	90.29%	169.81%	247.47%	271.57%	277.65%	250.35%	236.05%	219.46%	210.89%	214.31%
1990	1,253,640	544,563	106,837	437,726	34.92%	43.52%	65.46%	97.54%	113.44%	125.60%	121.20%	120.33%	116.61%	119.07%
1991	265,292	283,435	124,229	159,206	60.01%	39.30%	46.02%	64.69%	92.67%	106.82%	117.92%	114.31%	113.79%	110.63%
1992	679,154	257,592	189,751	67,841	9.99%	24.04%	30.24%	35.94%	50.21%	72.04%	83.50%	93.04%	90.97%	91.22%
1993	236,075	22,618	126,605	(103,987)	-44.05%	-3.95%	10.42%	23.04%	28.86%	42.27%	62.77%	73.65%	82.86%	81.23%
1994	207,963	355,249	97,881	257,368	123.76%	34.54%	19.70%	27.40%	30.97%	35.73%	47.90%	66.78%	76.84%	85.37%
1995	157,297	176,532	124,802	51,730	32.89%	84.62%	34.11%	21.32%	27.96%	31.07%	35.58%	47.15%	65.18%	74.82%
1996	75,286	43,887	114,390	(70,503)	-93.65%	-8.07%	54.16%	19.89%	14.93%	22.31%	27.81%	32.45%	43.88%	61.66%
1997	178,315	832,358	75,488	756,870	424.46%	270.65%	179.63%	160.85%	104.27%	62.53%	62.16%	50.97%	53.74%	63.72%
1998	409,975	270,319	123,277	147,042	35.87%	153.65%	125.59%	107.83%	111.05%	82.10%	56.91%	57.28%	49.19%	51.75%
1999	534,118	169,728	115,914	53,814	10.08%	21.28%	85.33%	74.08%	69.30%	76.54%	60.72%	46.82%	48.09%	43.96%
2000	265,029	130,300	77,995	52,305	19.74%	13.28%	20.94%	72.80%	64.23%	61.19%	68.31%	55.46%	44.20%	45.59%
2001	138,922	17,074	63,950	(46,876)	-33.74%	1.34%	6.32%	15.30%	63.10%	55.73%	53.69%	61.10%	49.83%	40.44%
2002	46,710	1,180	54,777	(53,597)	-114.74%	-54.12%	-10.69%	0.57%	10.95%	57.82%	50.90%	49.33%	57.02%	46.41%
2003	210,418	-	2,981	(2,981)	-1.42%	-22.00%	-26.12%	-7.74%	0.22%	9.33%	50.83%	44.98%	44.04%	51.49%
2004	82,296	-	93,947	(93,947)	-114.16%	-33.11%	-44.35%	-41.27%	-19.52%	-7.15%	3.30%	43.55%	38.23%	37.83%
2005	368,295	-	463,130	(463,130)	-125.75%	-123.63%	-84.73%	-86.71%	-78.02%	-54.71%	-33.69%	-19.82%	15.64%	12.08%
2006	749,130	-	150,174	(150,174)	-20.05%	-54.89%	-58.95%	-50.37%	-52.43%	-50.80%	-40.76%	-29.42%	-19.88%	6.68%
2007	216,824	0.00	544,491.27	(544,491)	-251.12%	-71.91%	-86.77%	-88.37%	-77.12%	-78.17%	-74.77%	-62.71%	-47.83%	-36.47%
2008	174,689	0.00	120,236.12	(120,236)	-68.83%	-169.78%	-71.44%	-84.70%	-86.22%	-76.32%	-77.29%	-74.24%	-63.19%	-49.14%
2009	116,985	0.00	197,695.85	(197,696)	-168.99%	-109.00%	-169.60%	-80.52%	-90.76%	-91.89%	-81.97%	-82.75%	-79.51%	-68.41%
2010	3,903,611	0.00	117,180.54	(117,181)	-3.00%	-7.83%	-10.37%	-22.20%	-21.89%	-28.81%	-30.06%	-29.02%	-29.71%	-29.80%
2011	253,494	0.00	706,087.49	(706,087)	-278.54%	-19.80%	-23.89%	-25.65%	-36.13%	-33.91%	-39.75%	-40.80%	-39.43%	-40.01%
2012	416,672	103,903	432,654	(328,750)	-78.90%	-154.42%	-25.19%	-28.77%	-30.21%	-39.64%	-37.12%	-42.39%	-43.33%	-41.97%
2013	218,642.00	141,133	957,849	(816,716)	-373.54%	-180.30%	-208.32%	-41.08%	-44.13%	-44.98%	-53.41%	-49.28%	-53.67%	-54.43%
2014	167,675.00	37,893	890,788	(852,894)	-508.66%	-432.19%	-248.87%	-255.99%	-56.89%	-59.47%	-59.78%	-67.37%	-61.67%	-65.25%
2015	401,496.00	120,987	694,992	(574,004)	-142.97%	-250.70%	-284.79%	-213.57%	-224.86%	-63.33%	-65.59%	-65.69%	-72.54%	-66.60%
2016	136,937.00	140,373	1,273,473	(1,133,100)	-827.46%	-317.05%	-362.55%	-365.15%	-276.23%	-276.60%	-82.36%	-84.17%	-83.70%	-89.75%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Underground Conductor & Devices
Account 367
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	93,490	50,082	15,872	34,210	36.59%									
1951	63,913	50,965	10,902	40,063	62.68%	47.19%								
1952	183,359	130,411	26,746	103,665	56.54%	58.13%	52.22%							
1953	142,748	84,917	15,659	69,258	48.52%	53.03%	54.61%	51.13%						
1954	139,539	109,656	21,235	88,421	63.37%	55.86%	56.13%	56.92%	53.87%					
1955	59,026	37,807	9,315	28,492	48.27%	58.88%	54.55%	55.24%	56.05%	53.38%				
1956	114,496	95,809	27,870	67,939	59.34%	55.57%	59.05%	55.75%	55.98%	56.58%	54.24%			
1957	200,828	130,961	35,067	95,894	47.75%	51.96%	51.38%	54.63%	53.30%	54.01%	54.62%	52.93%		
1958	163,745	102,672	30,846	71,826	43.86%	46.00%	49.19%	49.09%	52.03%	51.42%	52.35%	52.97%	51.65%	
1959	111,972	42,772	20,593	22,179	19.81%	34.09%	39.85%	43.62%	44.05%	47.46%	47.62%	49.09%	49.82%	48.85%
1960	140,008	101,055	22,854	78,201	55.85%	39.84%	41.42%	43.48%	45.97%	46.14%	48.72%	48.70%	49.84%	50.46%
1961	89,736	40,290	17,472	22,818	25.43%	43.97%	36.05%	38.58%	41.19%	43.72%	44.03%	46.67%	46.90%	48.21%
1962	262,727	89,462	29,894	59,568	22.67%	23.37%	32.61%	30.24%	33.14%	36.17%	38.62%	39.12%	41.76%	42.43%
1963	221,768	104,079	30,371	73,708	33.24%	27.51%	27.18%	32.80%	31.04%	33.16%	35.62%	37.70%	38.16%	40.50%
1964	212,267	91,610	36,742	54,868	25.85%	29.62%	27.00%	26.82%	31.21%	29.98%	31.87%	34.14%	36.05%	36.50%
1965	420,593	218,442	60,327	158,115	37.59%	33.65%	33.55%	30.99%	30.58%	33.20%	32.18%	33.35%	34.94%	36.38%
1966	506,932	342,511	75,339	267,172	52.70%	45.85%	42.13%	40.68%	37.77%	37.12%	38.53%	37.47%	37.96%	38.80%
1967	233,695	158,930	33,859	125,071	53.52%	52.96%	47.39%	44.06%	42.56%	39.75%	39.09%	40.21%	39.17%	39.50%
1968	521,097	346,413	65,328	281,085	53.94%	53.81%	53.37%	49.42%	46.78%	45.36%	42.86%	42.22%	42.95%	42.00%
1969	199,084	43,031	43,959	(928)	-0.47%	38.90%	42.48%	46.03%	44.14%	42.29%	41.42%	39.51%	39.04%	39.88%
1970	379,618	278,850	43,497	235,353	62.00%	40.51%	46.87%	48.04%	49.32%	47.14%	45.31%	44.32%	42.40%	41.90%
1971	215,316	200,327	45,394	154,933	71.96%	65.60%	49.04%	50.98%	51.36%	51.69%	49.30%	47.45%	46.36%	44.40%
1972	322,236	292,825	44,356	248,469	77.11%	75.04%	69.64%	57.14%	56.12%	55.80%	55.14%	52.50%	50.62%	49.43%
1973	271,263	132,931	35,840	97,091	35.79%	58.22%	61.88%	61.92%	52.97%	53.23%	53.26%	53.16%	51.02%	49.40%
1974	501,105	821,661	70,639	751,022	149.87%	109.81%	100.18%	95.54%	88.00%	78.68%	73.33%	71.58%	68.54%	64.90%
1975	357,319	257,860	63,168	194,692	54.49%	110.17%	92.31%	88.94%	86.74%	82.15%	74.83%	70.90%	69.54%	67.11%
1976	470,001	322,925	93,103	229,822	48.90%	51.31%	88.49%	79.55%	79.14%	78.42%	75.94%	70.34%	67.70%	66.75%
1977	739,923	451,934	146,640	305,294	41.26%	44.23%	46.57%	71.59%	67.44%	68.61%	68.86%	68.06%	64.12%	62.78%
1978	638,793	546,069	124,182	421,887	66.04%	52.74%	51.77%	52.21%	70.29%	67.14%	68.12%	68.35%	67.73%	64.42%
1979	672,919	638,122	147,498	490,624	72.91%	69.57%	59.36%	57.41%	57.05%	70.81%	68.21%	68.93%	69.08%	68.49%
1980	888,210	759,053	194,068	564,985	63.61%	67.62%	67.16%	60.64%	59.02%	58.59%	69.31%	67.31%	67.96%	68.13%
1981	1,019,372	1,181,797	219,113	962,684	94.44%	80.08%	78.21%	75.80%	69.34%	67.17%	66.23%	74.15%	72.28%	72.55%
1982	757,411	986,943	202,108	784,835	103.62%	98.35%	86.77%	83.98%	81.10%	74.85%	72.50%	71.34%	77.85%	76.04%
1983	835,466	583,706	185,935	397,771	47.61%	74.24%	82.12%	77.43%	76.70%	75.28%	70.75%	69.04%	68.23%	74.17%
1984	1,292,634	684,497	344,377	340,120	26.31%	34.67%	52.77%	63.65%	63.64%	64.78%	64.91%	62.36%	61.49%	61.17%
1985	1,513,861	980,441	251,807	728,634	48.13%	38.08%	40.27%	51.17%	59.31%	59.92%	61.17%	61.58%	59.78%	59.20%
1986	1,455,156	1,947,266	262,666	1,684,600	115.77%	81.28%	64.61%	61.82%	67.23%	71.26%	70.39%	70.59%	70.27%	68.08%
1987	2,004,356	1,925,561	222,726	1,702,835	84.96%	97.92%	82.76%	71.12%	68.35%	71.75%	74.36%	73.38%	73.35%	72.93%
1988	1,919,447	1,454,247	349,073	1,105,174	57.58%	71.56%	83.52%	75.75%	67.94%	66.06%	68.97%	71.37%	70.78%	70.90%
1989	2,647,807	2,020,800	342,965	1,677,835	63.37%	60.93%	68.26%	76.87%	72.31%	66.82%	65.45%	67.77%	69.80%	69.41%
1990	2,499,163	2,617,246	301,019	2,316,227	92.68%	77.60%	72.16%	74.99%	80.63%	76.54%	71.67%	70.25%	71.95%	73.38%
1991	2,299,456	934,202	362,628	571,574	24.86%	60.18%	61.31%	60.55%	64.85%	70.63%	68.25%	64.78%	63.91%	65.66%
1992	3,833,100	1,551,960	513,259	1,038,701	27.10%	26.26%	45.49%	49.69%	50.83%	55.33%	60.61%	59.57%	57.36%	56.96%
1993	3,281,693	1,203,248	402,337	800,911	24.41%	25.86%	25.61%	39.68%	43.99%	45.57%	49.84%	54.65%	54.19%	52.61%
1994	2,349,744	605,218	266,802	338,416	14.40%	20.23%	23.01%	23.37%	35.52%	39.88%	41.68%	45.84%	50.41%	50.26%
1995	2,680,366	1,490,184	269,941	1,220,243	45.53%	30.99%	28.39%	27.98%	27.48%	37.10%	40.65%	42.16%	45.81%	49.89%
1996	2,735,038	1,791,988	343,383	1,448,605	52.96%	49.28%	38.73%	34.47%	32.57%	31.54%	39.31%	42.16%	43.38%	46.55%
1997	3,142,168	1,115,533	438,616	676,917	21.54%	36.17%	39.10%	33.78%	31.61%	30.65%	29.99%	36.86%	39.62%	40.87%
1998	5,347,677	1,336,742	434,643	902,099	16.87%	18.60%	26.97%	30.55%	28.21%	27.57%	27.50%	27.26%	33.06%	35.67%
1999	5,617,672	1,676,053	513,006	1,163,047	20.70%	18.83%	19.44%	24.88%	27.72%	26.29%	26.04%	26.18%	26.08%	31.01%
2000	5,265,406	885,172	384,847	500,325	9.50%	15.28%	15.81%	16.74%	21.22%	23.85%	23.03%	23.18%	23.62%	23.69%
2001	5,171,356	79,102	548,632	(469,530)	-9.08%	0.30%	7.44%	9.79%	11.30%	15.47%	18.16%	17.89%	18.49%	19.33%
2002	3,761,758	90,112	272,122	(182,010)	-4.84%	-7.29%	-1.07%	5.11%	7.61%	9.15%	13.01%	15.60%	15.52%	16.26%
2003	1,478,221	78,826	6,220	72,607	4.91%	-2.09%	-5.56%	-0.50%	5.09%	7.46%	8.94%	12.64%	15.15%	15.10%
2004	2,482,444	586,853	190,980	395,873	15.95%	11.83%	3.71%	-1.42%	1.75%	6.23%	8.18%	9.48%	12.88%	15.20%
2005	4,275,419	637,591	1,669,831	(1,032,240)	-24.14%	-9.42%	-6.85%	-6.22%	-7.08%	-3.19%	1.60%	4.04%	5.55%	8.85%
2006	2,307,106	371,771	519,822	(148,050)	-6.42%	-17.93%	-8.65%	-6.75%	-6.25%	-7.00%	-3.49%	0.99%	3.37%	4.84%
2007	1,825,678	308,130	1,246,596	(938,466)	-51.40%	-26.29%	-25.20%	-15.82%	-13.34%	-11.36%	-10.81%	-6.78%	-1.98%	0.70%
2008	2,991,702	469,636	541,188	(71,552)	-2.39%	-20.97%	-16.25%	-19.21%	-12.93%	-11.21%	-9.96%	-9.77%	-6.34%	-2.02%
2009	3,401,648	322,997	624,811	(301,814)	-8.87%	-5.84%	-15.96%	-13.87%	-16.84%	-12.13%	-10.79%	-9.79%	-9.66%	-6.60%
2010	3,636,044	400,966	440,597	(39,630)	-1.09%	-4.85%	-4.12%	-11.40%	-10.59%	-13.73%	-10.21%	-9.21%	-8.58%	-8.66%
2011	4,905,454	387,026	310,599	76,428	1.56%	0.43%	-2.22%	-2.25%	-7.61%	-7.46%	-10.52%	-7.97%	-7.28%	-6.98%
2012	3,247,752	83,129	854,151	(771,023)	-23.74%	-8.52%	-6.23%	-6.82%	-6.09%	-10.23%	-9.83%	-12.13%	-9.74%	-9.03%
2013	3,526,934.14	46,991	775,578	(728,587)	-20.66%	-22.14%	-12.18%	-9.55%	-9.43%	-8.46%	-11.79%	-11.31%	-13.13%	-10.92%
2014	4,342,169.08	12,589	778,974	(766,384)	-17.65%	-19.00%	-20.38%	-13.67%	-11.34%	-10.98%	-9.99%	-12.70%	-12.22%	-13.70%
2015	4,186,323.80	297,233	893,960	(596,727)	-14.25%	-15.98%	-17.35%	-18.71%	-13.79%	-11.85%	-11.48%	-10.58%	-12.90%	-12.47%
2016	2,301,387.61	332,010	5,469,141	(5,137,131)	-223.22%	-88.38%	-60.02%	-50.35%	-45.44%	-35.20%	-30.46%	-27.97%	-25.62%	-26.99%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Line Transformers Amortized
Account 368
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	3,157,312	463,967	39,476	424,491	13.44%									
2001	29,650	85,129	14,809	70,320	237.17%	15.53%								
2002	2,025	-	45	(45)	-2.22%	221.86%	15.51%							
2003	64,060	-	(1,881)	1,881	2.94%	2.78%	75.37%	15.27%						
2004	331,003	75,526	238,090	(162,564)	-49.11%	-40.67%	-40.48%	-21.19%	9.32%					
2005	187,211	142,430	236,717	(94,287)	-50.36%	-49.56%	-43.79%	-43.64%	-30.08%	6.36%				
2006	46,568,279	441,331	285,212	156,119	0.34%	0.13%	-0.21%	-0.21%	-0.21%	-0.06%	0.79%			
2007	3,215,229	1,057,852	2,444,464	(1,386,612)	-43.13%	-2.47%	-2.65%	-2.96%	-2.95%	-2.95%	-2.81%	-1.85%		
2008	3,984,588	(17,746)	131,949	(149,695)	-3.76%	-21.34%	-2.57%	-2.73%	-3.02%	-3.01%	-3.01%	-2.88%	-1.98%	
2009	5,751,237 *	-	-	0	0.00%	-1.54%	-11.86%	-2.32%	-2.47%	-2.73%	-2.72%	-2.72%	-2.60%	-1.80%
2010	13,890,058 *	53,848	1,351,824	(1,297,977)	-9.34%	-6.61%	-6.13%	-10.56%	-3.65%	-3.77%	-3.97%	-3.96%	-3.96%	-3.87%
2011	6,846,074 *	-	1,297	(1,297)	-0.02%	-6.27%	-4.91%	-4.76%	-8.42%	-3.34%	-3.45%	-3.64%	-3.63%	-3.63%
2012		3,161		3,161	NA	0.03%	-6.25%	-4.89%	-4.74%	-8.41%	-3.33%	-3.44%	-3.63%	-3.63%
2013	7,923,285.00	77,228	1,963,283	(1,886,055)	-23.80%	-23.76%	-12.76%	-11.10%	-9.25%	-8.68%	-11.34%	-5.17%	-5.27%	-5.43%
2014	6,044,707.00		633,047	(633,047)	-10.47%	-18.03%	-18.01%	-12.09%	-10.99%	-9.43%	-8.92%	-11.23%	-5.51%	-5.60%
2015	6,266,381.00		626,212	(626,212)	-9.99%	-10.23%	-15.54%	-15.53%	-11.61%	-10.84%	-9.51%	-9.05%	-11.09%	-5.79%
2016	9,847,177.00		154	(154)	0.00%	-3.89%	-5.68%	-10.46%	-10.45%	-8.51%	-8.74%	-7.85%	-7.58%	-9.37%

* Includes 2012 Pro Forma Ret

Xcel Energy Electric Plant
Distribution Line Capacitors Amortized
Account 368
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	152,100	(2,012)	4,585	(6,597)	-4.34%									
2001	115,175	2,576	4,000	(1,424)	-1.24%	-3.00%								
2002	45,274	584	15,705	(15,121)	-33.40%	-10.31%	-7.40%							
2003	97,702	-	143	(143)	-0.15%	-10.68%	-6.46%	-5.68%						
2004	101,497	-	14,090	(14,090)	-13.88%	-7.15%	-12.01%	-8.56%	-7.30%					
2005	114,920	-	28,728	(28,728)	-25.00%	-19.79%	-13.68%	-16.16%	-12.54%	-10.55%				
2006	335,227	-	77,590	(77,590)	-23.15%	-23.62%	-21.83%	-18.57%	-19.53%	-16.93%	-14.94%			
2007	1,659,713	-	120,936	(120,936)	-7.29%	-9.95%	-10.77%	-10.91%	-10.46%	-10.90%	-10.45%	-10.09%		
2008	190,808	-	19,204	(19,204)	-10.06%	-7.57%	-9.96%	-10.71%	-10.85%	-10.43%	-10.84%	-10.42%	-10.09%	
2009	148,111	9,193	55,287	(46,093)	-31.12%	-19.27%	-9.32%	-11.30%	-11.95%	-12.02%	-11.59%	-11.95%	-11.51%	-11.14%
2010	127,405	33,100	14,377	18,723	14.70%	-9.93%	-9.99%	-7.88%	-9.96%	-10.63%	-10.75%	-10.38%	-10.75%	-10.38%
2011	119,973 *	-	67,746	(67,746)	-56.47%	-19.82%	-24.05%	-19.50%	-10.47%	-12.12%	-12.67%	-12.71%	-12.29%	-12.61%
2012	142,786 *	18,107	25,230	(7,123)	-4.99%	-28.49%	-14.39%	-18.99%	-16.66%	-10.15%	-11.75%	-12.28%	-12.34%	-11.95%
2013	110,393.92	23	48,373	(48,350)	-43.80%	-21.91%	-33.02%	-20.88%	-23.22%	-20.23%	-11.63%	-12.99%	-13.46%	-13.48%
2014	2,489,478.16	41,111	45,088	(3,978)	-0.16%	-2.01%	-2.17%	-4.44%	-3.63%	-4.93%	-5.22%	-5.91%	-6.99%	-7.37%
2015	410,776.66	-7	51,544	(51,551)	-12.55%	-1.91%	-3.45%	-3.52%	-5.46%	-4.71%	-5.81%	-6.03%	-6.41%	-7.39%
2016	71,203.39	158	24,029	(23,870)	-33.52%	-15.65%	-2.67%	-4.15%	-4.18%	-6.06%	-5.30%	-6.35%	-6.54%	-6.77%

* Includes 2012 Pro Forma Ret

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Services - Overhead
Account 369
1955-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1955	78,289	44,068	41,401	2,667	3.41%									
1956	98,392	60,182	52,330	7,852	7.98%	5.95%								
1957	116,813	53,514	63,107	(9,593)	-8.21%	-0.81%	0.32%							
1958	141,761	39,972	76,539	(36,567)	-25.79%	-17.85%	-10.73%	-8.19%						
1959	128,718	43,153	78,309	(35,156)	-27.31%	-26.52%	-21.00%	-15.13%	-12.55%					
1960	138,190	50,235	82,908	(32,673)	-23.64%	-25.41%	-25.55%	-21.69%	-17.01%	-14.74%				
1961	128,003	44,446	83,535	(39,089)	-30.54%	-26.96%	-27.07%	-26.74%	-23.42%	-19.32%	-17.17%			
1962	150,353	61,503	100,337	(38,834)	-25.83%	-27.99%	-26.55%	-26.73%	-26.54%	-23.87%	-20.40%	-18.50%		
1963	136,839	49,547	90,344	(40,797)	-29.81%	-27.73%	-28.59%	-27.36%	-27.35%	-27.08%	-24.74%	-21.64%	-19.89%	-19.89%
1964	129,314	53,320	95,879	(42,559)	-32.91%	-31.32%	-29.34%	-29.62%	-28.41%	-28.24%	-27.87%	-25.73%	-22.89%	-21.24%
1965	155,344	53,216	96,462	(43,246)	-27.84%	-30.14%	-30.04%	-28.93%	-29.22%	-28.30%	-28.17%	-27.87%	-25.99%	-23.47%
1966	147,049	77,054	113,521	(36,467)	-24.80%	-26.36%	-28.32%	-28.68%	-28.09%	-28.46%	-27.78%	-27.73%	-27.51%	-25.87%
1967	173,647	70,291	141,052	(70,761)	-40.75%	-33.44%	-31.61%	-31.89%	-31.51%	-30.55%	-30.55%	-29.72%	-29.48%	-29.12%
1968	159,731	77,731	145,742	(68,011)	-42.58%	-41.63%	-36.48%	-34.37%	-34.12%	-33.47%	-32.38%	-32.18%	-31.28%	-30.93%
1969	179,189	79,641	176,224	(96,583)	-53.90%	-48.56%	-45.92%	-41.21%	-38.66%	-37.87%	-36.85%	-35.51%	-35.04%	-33.99%
1970	185,653	83,915	173,043	(89,128)	-48.01%	-50.90%	-48.37%	-46.47%	-42.70%	-40.39%	-39.54%	-38.49%	-37.14%	-36.60%
1971	190,904	58,777	186,492	(127,715)	-66.90%	-57.59%	-56.40%	-53.31%	-50.86%	-47.16%	-44.64%	-43.49%	-42.21%	-40.68%
1972	204,596	62,581	196,611	(134,030)	-65.51%	-66.18%	-60.38%	-58.85%	-56.02%	-53.60%	-50.19%	-47.70%	-46.45%	-45.08%
1973	214,283	76,809	182,391	(105,582)	-49.27%	-57.20%	-60.24%	-57.38%	-56.74%	-54.75%	-52.89%	-50.05%	-47.91%	-46.79%
1974	240,907	85,789	185,355	(99,566)	-41.33%	-45.07%	-51.41%	-54.88%	-53.65%	-53.69%	-52.40%	-51.09%	-48.81%	-47.05%
1975	245,205	93,618	204,763	(111,145)	-45.33%	-43.35%	-45.16%	-49.76%	-52.75%	-52.06%	-52.29%	-51.33%	-50.30%	-48.37%
1976	290,507	70,301	192,046	(121,745)	-41.91%	-43.47%	-42.81%	-44.21%	-47.85%	-50.47%	-50.18%	-50.56%	-49.90%	-49.13%
1977	333,693	74,177	202,641	(128,464)	-38.50%	-40.08%	-41.56%	-41.51%	-42.77%	-45.81%	-48.15%	-48.14%	-48.63%	-48.20%
1978	359,362	54,690	326,604	(271,914)	-75.67%	-57.77%	-53.08%	-51.54%	-49.86%	-49.79%	-51.49%	-52.91%	-52.50%	-52.61%
1979	413,293	87,998	479,709	(391,711)	-94.78%	-85.89%	-71.59%	-65.42%	-62.42%	-59.72%	-58.65%	-59.26%	-59.85%	-59.03%
1980	404,209	142,608	550,526	(407,918)	-100.92%	-97.81%	-91.05%	-79.44%	-73.39%	-70.02%	-67.00%	-65.48%	-65.49%	-65.58%
1981	401,709	466,315	531,504	(65,189)	-16.23%	-58.70%	-70.93%	-72.01%	-66.16%	-62.96%	-61.20%	-59.42%	-58.67%	-59.12%
1982	375,243	141,582	394,170	(252,588)	-67.31%	-40.90%	-61.44%	-70.08%	-71.11%	-66.35%	-63.60%	-62.01%	-60.38%	-59.66%
1983	341,936	158,070	282,496	(124,426)	-36.39%	-52.57%	-39.52%	-55.82%	-64.13%	-65.94%	-62.45%	-60.41%	-59.24%	-57.98%
1984	318,512	305,507	349,803	(44,296)	-13.91%	-25.55%	-40.68%	-33.85%	-48.57%	-57.04%	-59.60%	-57.21%	-55.84%	-55.10%
1985	374,154	206,022	447,537	(241,515)	-64.55%	-41.26%	-39.65%	-47.01%	-40.19%	-51.27%	-58.11%	-60.22%	-58.04%	-56.74%
1986	287,274	174,066	382,817	(208,751)	-72.67%	-68.07%	-50.47%	-46.83%	-51.36%	-44.63%	-53.72%	-59.54%	-61.31%	-59.20%
1987	311,152	167,006	369,964	(202,958)	-65.23%	-68.80%	-67.16%	-54.03%	-50.33%	-53.51%	-47.29%	-54.99%	-60.09%	-61.65%
1988	303,333	218,902	360,992	(142,090)	-46.84%	-56.15%	-61.41%	-62.33%	-52.66%	-49.79%	-52.63%	-47.24%	-54.20%	-58.95%
1989	317,185	108,619	357,208	(248,589)	-78.37%	-62.96%	-63.72%	-65.83%	-65.53%	-56.93%	-53.81%	-55.74%	-50.50%	-56.43%
1990	363,158	276,239	337,830	(61,591)	-16.96%	-45.59%	-45.98%	-50.60%	-54.61%	-56.51%	-50.55%	-48.70%	-51.03%	-46.91%
1991	330,587	229,707	331,833	(102,126)	-30.89%	-23.60%	-40.78%	-42.18%	-46.59%	-50.51%	-52.81%	-48.05%	-46.70%	-49.03%
1992	339,603	47,509	409,498	(361,989)	-106.59%	-69.25%	-50.87%	-57.33%	-55.41%	-56.96%	-58.97%	-59.76%	-54.80%	-52.89%
1993	322,985	14,027	365,822	(351,795)	-108.92%	-107.73%	-82.15%	-64.70%	-67.29%	-64.15%	-64.30%	-65.23%	-65.14%	-60.15%
1994	300,586	25,875	345,031	(319,156)	-106.18%	-107.60%	-107.24%	-87.73%	-72.22%	-73.21%	-69.70%	-69.16%	-69.51%	-68.94%
1995	300,617	34,172	337,189	(303,017)	-100.80%	-103.49%	-105.39%	-105.71%	-90.20%	-76.61%	-76.86%	-73.32%	-72.45%	-72.47%
1996	435,457	38,479	349,321	(310,842)	-71.38%	-83.40%	-90.00%	-94.50%	-96.91%	-86.16%	-75.66%	-75.98%	-73.04%	-72.31%
1997	249,074	54,203	258,592	(204,389)	-82.06%	-75.27%	-83.06%	-88.46%	-92.57%	-95.01%	-85.71%	-76.26%	-76.49%	-73.73%
1998	524,311	79,562	419,657	(340,095)	-64.87%	-70.40%	-70.76%	-76.74%	-81.63%	-85.76%	-88.62%	-81.81%	-74.38%	-74.74%
1999	388,976	52,904	345,228	(292,324)	-75.15%	-69.25%	-71.99%	-71.83%	-76.41%	-80.48%	-84.12%	-86.79%	-81.00%	-74.46%
2000	461,222	27,061	357,227	(330,166)	-71.59%	-73.22%	-70.03%	-71.88%	-71.77%	-75.47%	-78.94%	-82.19%	-84.68%	-79.81%
2001	354,711	13,184	426,128	(412,944)	-116.42%	-91.07%	-85.93%	-79.55%	-79.86%	-78.33%	-80.82%	-83.35%	-85.82%	-87.74%
2002	249,468	19,893	259,969	(240,075)	-96.23%	-108.08%	-92.28%	-87.70%	-81.65%	-81.70%	-80.01%	-82.12%	-84.33%	-86.55%
2003	-	-	45,729	(45,729)	NA	-114.57%	-115.65%	-96.58%	-90.85%	-83.96%	-83.75%	-81.73%	-83.66%	-85.73%
2004	52,804	-	124,165	(124,165)	-235.14%	-321.75%	-135.63%	-125.26%	-103.12%	-95.90%	-87.89%	-87.25%	-84.71%	-86.31%
2005	144,545	-	285,411	(285,411)	-197.46%	-207.54%	-230.71%	-155.63%	-138.28%	-113.92%	-104.79%	-95.17%	-93.82%	-90.41%
2006	979,421	-	375,647	(375,647)	-38.35%	-58.81%	-66.73%	-70.61%	-75.09%	-83.32%	-80.91%	-80.06%	-77.53%	-77.87%
2007	81,302	-	1,336,427	(1,336,427)	-1643.77%	-161.41%	-165.73%	-168.64%	-172.28%	-159.69%	-151.45%	-135.60%	-126.93%	-116.88%
2008	1,633,914	-	617,067	(617,067)	-37.77%	-113.89%	-86.44%	-92.09%	-94.70%	-96.28%	-96.28%	-98.32%	-95.21%	-93.41%
2009	36,807	-	669,233	(669,233)	-1818.20%	-76.99%	-149.70%	-109.77%	-114.18%	-116.36%	-117.92%	-116.22%	-116.24%	-111.08%
2010	773,153	-	557,916	(557,916)	-72.16%	-151.51%	-75.46%	-125.96%	-101.47%	-105.28%	-107.13%	-108.36%	-107.60%	-108.33%
2011	909,949	-	574,424	(574,424)	-63.13%	-67.28%	-104.75%	-72.12%	-109.31%	-93.57%	-96.86%	-98.45%	-99.44%	-99.27%
2012	371,600	3,002	643,882	(640,880)	-172.47%	-94.83%	-86.30%	-116.78%	-82.13%	-115.48%	-99.70%	-102.56%	-103.97%	-104.88%
2013	528,693.00	4,172	604,319	(600,147)	-113.52%	-137.85%	-100.29%	-91.87%	-116.12%	-86.03%	-115.24%	-101.07%	-103.62%	-104.88%
2014	142,101.00	8,385	410,583	(402,198)	-283.04%	-149.43%	-157.64%	-113.59%	-101.84%	-124.71%	-92.39%	-120.56%	-105.81%	-108.17%
2015	181,650.00	2,958	669,866	(666,908)	-367.14%	-330.22%	-195.82%	-188.73%	-135.17%	-118.41%	-139.67%	-103.30%	-130.18%	-114.23%
2016	598,408.00	2,346	666,118	(663,772)	-110.92%	-170.59%	-187.92%	-160.80%	-163.18%	-129.86%	-117.14%	-134.81%	-104.18%	-127.99%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Services - Underground
Account 369
1955-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1955	15,561	-	-	0	0.00%									
1956	21,535	-	-	0	0.00%	0.00%								
1957	33,188	-	-	0	0.00%	0.00%	0.00%							
1958	35,437	-	-	0	0.00%	0.00%	0.00%	0.00%						
1959	39,164	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%					
1960	29,921	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
1961	37,698	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
1962	78,921	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
1963	63,080	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
1964	59,551	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1965	38,834	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1966	42,790	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1967	32,324	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1968	28,758	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1969	36,639	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1970	20,722	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1971	51,365	7,629	9,816	(2,187)	-4.26%	-3.03%	-2.01%	-1.59%	-1.29%	-1.03%	-0.87%	-0.70%	-0.58%	-0.48%
1972	21,618	6,241	4,505	1,736	8.03%	-0.62%	-0.48%	-0.35%	-0.28%	-0.24%	-0.19%	-0.17%	-0.14%	-0.11%
1973	12,215	1,842	5,016	(3,174)	-25.98%	-4.25%	-4.25%	-3.42%	-2.54%	-2.12%	-1.78%	-1.47%	-1.27%	-1.05%
1974	59,025	37,755	10,328	27,427	46.47%	34.04%	27.99%	16.50%	14.43%	11.81%	10.33%	9.06%	7.79%	6.91%
1975	37,490	14,128	6,717	7,411	19.77%	36.10%	29.12%	25.62%	17.18%	15.42%	13.06%	11.65%	10.40%	9.10%
1976	36,134	13,424	9,811	3,613	10.00%	14.97%	28.99%	24.35%	22.23%	15.99%	14.60%	12.65%	11.46%	10.36%
1977	42,703	9,697	9,683	14	0.03%	4.60%	9.49%	21.94%	18.82%	17.70%	13.37%	12.39%	10.96%	10.05%
1978	34,048	18,302	7,475	10,827	31.80%	14.12%	12.80%	14.54%	23.54%	20.81%	19.67%	15.50%	14.48%	12.98%
1979	52,347	12,078	9,932	2,146	4.10%	15.02%	10.06%	10.05%	11.84%	19.65%	17.62%	16.92%	13.78%	13.00%
1980	49,478	15,843	15,337	506	1.02%	2.60%	9.92%	7.56%	7.97%	9.72%	16.69%	15.08%	14.64%	12.19%
1981	98,858	15,858	18,490	(2,632)	-2.66%	-1.43%	0.01%	4.62%	3.91%	4.62%	6.23%	12.02%	10.93%	10.78%
1982	43,641	18,004	15,589	2,415	5.53%	-0.15%	0.15%	1.00%	4.76%	4.13%	4.73%	6.16%	11.40%	10.42%
1983	65,978	9,466	18,018	(8,552)	-12.96%	-5.60%	-4.21%	-3.20%	-1.97%	1.37%	1.22%	1.97%	3.42%	8.31%
1984	37,283	129,166	15,003	114,163	306.21%	102.28%	73.54%	42.88%	35.87%	31.08%	31.15%	28.02%	26.60%	26.09%
1985	65,036	169,810	21,408	148,402	228.18%	256.61%	150.93%	120.99%	81.66%	70.59%	62.15%	59.84%	54.62%	51.55%
1986	100,730	269,003	27,453	241,550	239.80%	235.24%	248.27%	184.21%	159.27%	120.37%	107.56%	97.01%	92.95%	86.23%
1987	38,717	154,076	19,941	134,135	346.45%	269.41%	256.30%	263.99%	204.62%	179.89%	139.81%	126.07%	114.50%	109.70%
1988	74,248	293,910	20,441	273,469	368.32%	360.82%	303.78%	286.14%	288.51%	236.44%	212.76%	172.16%	157.41%	144.59%
1989	169,392	59,375	21,720	37,655	22.23%	127.70%	157.69%	179.28%	186.38%	195.58%	170.63%	158.52%	135.56%	126.60%
1990	120,584	310,179	12,478	297,701	246.88%	115.65%	167.16%	184.38%	195.47%	199.21%	205.79%	184.31%	173.41%	152.04%
1991	131,823	271,154	8,896	262,258	198.95%	221.85%	141.68%	175.60%	187.97%	196.19%	199.16%	204.57%	186.71%	177.38%
1992	499,644	159,773	21,882	137,891	27.60%	63.37%	92.79%	79.82%	101.33%	110.51%	121.98%	127.74%	133.11%	125.72%
1993	255,702	127,189	13,467	113,722	44.47%	33.31%	57.92%	80.53%	72.14%	89.72%	97.42%	107.73%	113.11%	117.93%
1994	36,913	138,817	8,874	129,943	352.03%	83.27%	48.16%	69.67%	90.13%	80.65%	97.23%	104.50%	114.05%	119.02%
1995	83,862	168,189	15,740	152,449	181.79%	233.82%	105.22%	60.95%	79.00%	96.94%	87.19%	102.40%	109.10%	117.81%
1996	104,526	223,492	21,081	202,411	193.65%	188.37%	215.18%	124.43%	75.09%	89.77%	105.14%	95.12%	108.86%	114.93%
1997	79,911	333,743	25,611	308,132	385.59%	276.81%	247.11%	259.80%	161.64%	98.49%	109.60%	122.20%	110.78%	123.06%
1998	71,191	37,307	9,144	28,163	39.56%	222.56%	210.74%	203.59%	218.14%	147.89%	94.78%	105.65%	117.95%	107.52%
1999	90,394	81,695	13,289	68,406	75.68%	59.76%	167.58%	175.45%	176.69%	190.55%	138.86%	93.37%	103.65%	115.36%
2000	24,903	82,666	7,259	75,407	302.80%	124.73%	92.22%	180.22%	184.00%	183.60%	196.24%	144.32%	97.55%	107.25%
2001	43,576	567	6,891	(6,324)	-14.51%	100.88%	86.54%	72.00%	152.85%	163.13%	166.27%	179.08%	135.57%	93.77%
2002	250,811	0	2,994	(2,993)	-1.19%	-3.16%	20.70%	32.83%	33.83%	83.95%	101.19%	110.21%	121.56%	102.64%
2003	-	-	397	(397)	NA	-1.35%	-3.30%	20.57%	32.73%	33.74%	83.88%	101.13%	110.16%	121.51%
2004	19,082	-	29,045	(29,045)	-152.21%	-154.29%	-12.02%	-12.36%	10.83%	24.50%	26.65%	76.11%	94.06%	103.64%
2005	26,575	-	20,900	(20,900)	-78.64%	-109.39%	-110.26%	-17.99%	-17.54%	4.32%	18.48%	21.33%	69.33%	87.61%
2006	441,544	-	29,724	(29,724)	-6.73%	-10.81%	-16.35%	-16.43%	-11.25%	-11.44%	-1.73%	6.07%	8.53%	37.28%
2007	47,883	-	(16,799)	16,799	35.08%	-2.64%	-6.56%	-11.75%	-11.82%	-8.43%	-8.75%	0.33%	7.54%	9.78%
2008	192,597	-	50,960	(50,960)	-26.46%	-14.21%	-9.37%	-11.97%	-15.64%	-15.70%	-11.98%	-12.09%	-4.60%	1.78%
2009	94,303	-	22,993	(22,993)	-24.38%	-25.78%	-17.07%	-11.19%	-13.42%	-16.65%	-16.69%	-13.07%	-13.13%	-6.23%
2010	681,237	-	26,478	(26,478)	-3.89%	-6.38%	-10.37%	-8.23%	-7.78%	-9.05%	-10.86%	-10.89%	-9.50%	-9.62%
2011	2,711,802	-	40,934	(40,934)	-1.51%	-1.99%	-2.59%	-3.84%	-3.34%	-3.70%	-4.18%	-4.85%	-4.85%	-4.65%
2012	14,872	549	29,850	(29,301)	-197.02%	-2.58%	-2.84%	-3.42%	-4.62%	-4.11%	-4.39%	-4.86%	-5.52%	-5.53%
2013	52,766.00	6,274	32,865	(26,591)	-50.39%	-82.63%	-3.48%	-3.56%	-4.12%	-5.26%	-4.75%	-4.96%	-5.42%	-6.07%
2014	24,955.00	8,985	27,479	(18,494)	-74.11%	-58.01%	-80.34%	-4.11%	-4.07%	-4.60%	-5.72%	-5.21%	-5.37%	-5.82%
2015	39,837.00	1,352	26,438	(25,086)	-62.97%	-67.26%	-59.69%	-75.11%	-4.94%	-4.73%	-5.25%	-6.32%	-5.80%	-5.90%
2016	253,785.00	2,868	96,575	(93,707)	-36.92%	-40.46%	-43.09%	-44.13%	-50.02%	-7.56%	-6.90%	-7.32%	-8.23%	-7.72%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Meters
Account 370 Amortized
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	10,592,788	42,596	(30,318)	72,914	0.69%									
2001	3,182	85,129	14,809	70,320	2209.92%	1.35%								
2002		75,526	45	75,481	NA	4582.04%	2.06%							
2003		142,430	(1,881)	144,310	NA	NA	9117.24%	3.43%						
2004		441,331	238,090	203,240	NA	NA	NA	15504.41%	5.34%					
2005			236,717	(236,717)	NA	NA	NA	NA	8065.18%	3.11%				
2006	22,937,302		285,212	(285,212)	-1.24%	-2.28%	-1.39%	-0.76%	-0.43%	-0.12%	0.13%			
2007	2,666,205		789,129	(789,129)	-29.60%	-4.20%	-5.12%	-4.33%	-3.76%	-3.47%	-3.19%	-2.06%		
2008	3,503,616	-	-	0	0.00%	-12.79%	-3.69%	-4.50%	-3.81%	-3.31%	-3.05%	-2.81%	-1.88%	
2009	-	-	-	0	NA	0.00%	-12.79%	-3.69%	-4.50%	-3.81%	-3.31%	-3.05%	-2.81%	-1.88%
2010	-	2,583	493,066	(490,483)	NA	NA	-14.00%	-20.74%	-5.38%	-6.19%	-5.49%	-5.00%	-4.74%	-4.49%
2011	-	-	-	0	NA	NA	NA	-14.00%	-20.74%	-5.38%	-6.19%	-5.49%	-5.00%	-4.74%
2012	-	-	-	0	NA	NA	NA	NA	-14.00%	-20.74%	-5.38%	-6.19%	-5.49%	-5.00%
2013	0.00	18,007	587,691	(569,684)	NA	NA	NA	NA	NA	-30.26%	-29.97%	-7.33%	-8.15%	-7.45%
2014	5,067,823.04	7,983	249,747	(241,765)	-4.77%	-16.01%	-16.01%	-16.01%	-25.69%	-25.69%	-15.19%	-18.61%	-6.95%	-7.65%
2015	4,471,117.39	24,493	383,684	(359,190)	-8.03%	-6.30%	-12.27%	-12.27%	-12.27%	-17.41%	-17.41%	-12.74%	-15.60%	-7.08%
2016	5,082,204.03	2,373		2,373	0.05%	-3.74%	-4.09%	-7.99%	-7.99%	-7.99%	-11.34%	-11.34%	-9.15%	-11.77%

Xcel Energy Electric Plant
Distribution Meters - Old
Account 370 Amortized
2009-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %					
2009	4,990,401 *			0	0.00%							
2010	6,616,114 *	-	-	0	0.00%	0.00%						
2011	3,451,141 *	-	-	0	0.00%	0.00%	0.00%					
2012		-	-	0	NA	0.00%	0.00%	0.00%				
2013	1,949,431.00	0	-	0	0.00%	0.00%	0.00%	0.00%	0.00%			
2014	0.00	0	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%		
2015	0.00	0	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	
2016		0		0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%

* Includes Pro Forma 2012 Ret

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
Distribution Street Lighting & Signal Systems
Account 373
1955-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1955	45,282	13,024	8,558	4,466	9.86%									
1956	98,064	19,123	12,940	6,183	6.31%	7.43%								
1957	113,535	32,939	21,055	11,884	10.47%	8.54%	8.77%							
1958	97,968	28,008	19,741	8,267	8.44%	9.53%	8.51%	8.68%						
1959	104,720	15,232	19,566	(4,334)	-4.14%	1.94%	5.00%	5.31%	5.76%					
1960	112,863	21,037	26,653	(5,616)	-4.98%	-4.57%	-0.53%	2.38%	3.11%	3.64%				
1961	84,664	15,472	18,249	(2,777)	-3.28%	-4.25%	-4.21%	-1.11%	1.45%	2.22%	2.75%			
1962	108,867	18,231	24,511	(6,280)	-5.77%	-4.68%	-4.79%	-4.62%	-2.11%	0.18%	1.02%	1.54%		
1963	135,027	18,581	32,482	(13,901)	-10.29%	-8.27%	-6.99%	-6.47%	-6.03%	-3.83%	-1.68%	-0.77%	-0.23%	
1964	147,898	23,380	33,157	(9,777)	-6.61%	-8.37%	-7.65%	-6.87%	-6.51%	-6.15%	-4.35%	-2.49%	-1.63%	-1.13%
1965	198,411	24,400	40,946	(16,546)	-8.34%	-7.60%	-8.36%	-7.88%	-7.30%	-6.97%	-6.64%	-5.15%	-3.54%	-2.74%
1966	390,977	33,420	29,982	3,438	0.88%	-2.22%	-3.10%	-4.22%	-4.39%	-4.30%	-4.37%	-4.35%	-3.44%	-2.38%
1967	781,062	29,859	36,922	(7,063)	-0.90%	-0.31%	-1.47%	-1.97%	-2.65%	-2.84%	-2.86%	-2.99%	-3.04%	-2.52%
1968	832,357	36,970	39,968	(2,998)	-0.36%	-0.62%	-0.33%	-1.05%	-1.40%	-1.88%	-2.05%	-2.09%	-2.20%	-2.27%
1969	649,596	38,158	46,613	(8,455)	-1.30%	-0.77%	-0.82%	-0.57%	-1.11%	-1.38%	-1.76%	-1.90%	-1.93%	-2.03%
1970	582,796	39,239	48,774	(9,535)	-1.64%	-1.46%	-1.02%	-0.99%	-0.76%	-1.20%	-1.42%	-1.74%	-1.86%	-1.89%
1971	191,907	26,443	29,395	(2,952)	-1.54%	-1.61%	-1.47%	-1.06%	-1.02%	-0.80%	-1.22%	-1.43%	-1.73%	-1.84%
1972	153,187	29,621	27,405	2,216	1.45%	-0.21%	-1.11%	-1.19%	-0.90%	-0.90%	-0.71%	-1.11%	-1.32%	-1.61%
1973	139,929	30,069	24,328	5,741	4.10%	2.71%	1.03%	-0.42%	-0.76%	-0.63%	-0.69%	-0.53%	-0.92%	-1.13%
1974	210,094	97,205	33,006	64,199	30.56%	19.98%	14.34%	9.96%	4.67%	2.66%	1.75%	1.16%	1.13%	0.68%
1975	182,139	37,490	33,513	3,977	2.18%	17.38%	13.89%	11.11%	8.34%	4.36%	2.62%	1.77%	1.21%	1.18%
1976	234,657	55,269	48,488	6,781	2.89%	2.58%	11.96%	10.52%	9.01%	7.19%	4.16%	2.64%	1.86%	1.31%
1977	178,395	42,481	50,131	(7,650)	-4.29%	-0.21%	0.52%	8.36%	7.73%	6.85%	5.60%	3.35%	2.15%	1.53%
1978	198,377	61,339	58,076	3,263	1.64%	-1.16%	0.39%	0.80%	7.03%	6.67%	6.06%	5.08%	3.19%	2.12%
1979	177,221	57,713	66,899	(9,186)	-5.18%	-1.58%	-2.45%	-0.86%	-0.29%	5.20%	5.08%	4.70%	3.99%	2.53%
1980	176,462	58,673	68,525	(9,852)	-5.58%	-5.38%	-2.86%	-3.21%	-1.72%	-1.10%	3.80%	3.83%	3.60%	3.07%
1981	148,300	53,533	77,910	(24,377)	-16.44%	-10.54%	-8.65%	-5.73%	-5.44%	-3.68%	-2.86%	1.80%	2.00%	1.95%
1982	136,777	40,811	60,339	(19,528)	-14.28%	-15.40%	-11.65%	-9.85%	-7.13%	-6.63%	-4.84%	-3.95%	0.46%	0.75%
1983	118,008	31,606	52,320	(20,714)	-17.55%	-15.79%	-16.03%	-12.85%	-11.05%	-8.42%	-7.77%	-5.94%	-4.99%	-0.74%
1984	716,245	50,749	159,086	(108,337)	-15.13%	-15.47%	-15.30%	-15.45%	-14.11%	-13.03%	-11.29%	-10.62%	-9.10%	-8.19%
1985	1,387,873	34,400	259605	(225,205)	-16.23%	-15.85%	-15.94%	-15.85%	-15.88%	-15.20%	-14.58%	-13.53%	-13.02%	-11.95%
1986	1,035,741	33,923	200,721	(166,798)	-16.10%	-16.17%	-15.94%	-15.99%	-15.92%	-15.95%	-15.45%	-14.99%	-14.18%	-13.77%
1987	1,333,674	25,756	199,503	(173,747)	-13.03%	-14.37%	-15.06%	-15.07%	-15.13%	-15.11%	-15.15%	-14.81%	-14.49%	-13.90%
1988	683,151	19,557	112,551	(92,994)	-13.61%	-13.23%	-14.20%	-14.84%	-14.88%	-14.94%	-14.92%	-14.96%	-14.67%	-14.39%
1989	275,407	30,142	61,300	(31,158)	-11.31%	-12.95%	-13.00%	-13.96%	-14.63%	-14.69%	-14.76%	-14.74%	-14.79%	-14.52%
1990	137,365	25,917	42,208	(16,291)	-11.86%	-11.50%	-12.82%	-12.93%	-13.88%	-14.55%	-14.62%	-14.69%	-14.68%	-14.72%
1991	148,600	17,776	48,019	(30,243)	-20.35%	-16.27%	-13.84%	-13.71%	-13.36%	-14.15%	-14.72%	-14.77%	-14.83%	-14.82%
1992	133,996	34,465	49,760	(15,295)	-11.41%	-16.11%	-14.72%	-13.37%	-13.49%	-13.26%	-14.05%	-14.64%	-14.70%	-14.75%
1993	128,840	27,467	59,703	(32,236)	-25.02%	-18.08%	-18.90%	-17.14%	-15.19%	-14.48%	-13.80%	-14.41%	-14.89%	-14.92%
1994	165,798	71,286	53,578	17,708	10.68%	-4.93%	-6.96%	-10.41%	-10.69%	-10.86%	-11.98%	-12.45%	-13.38%	-14.11%
1995	138,413	(24,541)	53,423	(77,964)	-56.33%	-19.81%	-21.36%	-19.01%	-19.29%	-18.09%	-16.44%	-15.37%	-14.38%	-14.81%
1996	110,953	28,296	55,590	(27,294)	-24.60%	-42.21%	-21.09%	-22.02%	-19.92%	-20.00%	-18.84%	-17.17%	-15.90%	-14.73%
1997	97,668	53,905	70,996	(17,091)	-17.50%	-21.28%	-35.26%	-20.40%	-21.33%	-19.62%	-19.74%	-18.72%	-17.19%	-15.98%
1998	176,142	34,429	92,376	(57,947)	-32.90%	-27.41%	-26.60%	-34.46%	-23.60%	-23.82%	-22.08%	-21.84%	-20.74%	-19.02%
1999	200,837	6,915	13,148	(6,233)	-3.10%	-17.02%	-17.12%	-18.54%	-25.76%	-18.97%	-19.74%	-18.77%	-18.95%	-18.27%
2000	258,392	17,517	13,006	4,511	1.75%	-0.37%	-9.39%	-10.47%	-12.33%	-18.53%	-14.31%	-15.39%	-15.01%	-15.52%
2001	327,424	19,419	138,277	(118,858)	-36.30%	-19.52%	-15.33%	-18.54%	-18.45%	-19.03%	-22.97%	-19.19%	-19.66%	-19.02%
2002	364,343	-	257,437	(257,437)	-70.66%	-54.40%	-39.13%	-32.84%	-32.85%	-31.80%	-31.28%	-33.35%	-29.38%	-29.10%
2003	133,071	-	(845)	845	0.64%	-51.59%	-45.52%	-34.24%	-29.37%	-29.80%	-29.03%	-28.73%	-30.85%	-27.36%
2004	370,266	-	24,804	(24,804)	-6.70%	-4.76%	-32.43%	-33.49%	-27.23%	-24.30%	-25.13%	-24.74%	-24.73%	-26.74%
2005	234,515	-	58,178	(58,178)	-24.81%	-13.72%	-11.13%	-30.81%	-32.07%	-26.89%	-24.36%	-25.09%	-24.75%	-24.74%
2006	4,732,477	-	296,301	(296,301)	-6.26%	-7.14%	-7.11%	-6.92%	-10.90%	-12.25%	-11.68%	-11.42%	-11.98%	-12.06%
2007	454,489	-	969,243	(969,243)	-213.26%	-24.40%	-24.42%	-23.28%	-22.75%	-25.52%	-26.06%	-25.01%	-24.39%	-24.60%
2008	495,677	-	258,771	(258,771)	-52.21%	-129.24%	-26.82%	-26.74%	-25.56%	-25.02%	-27.47%	-27.88%	-26.84%	-26.21%
2009	577,607	-	363,620	(363,620)	-62.95%	-57.99%	-104.18%	-30.16%	-29.96%	-28.71%	-28.15%	-30.26%	-30.51%	-29.46%
2010	611,057	-	397,877	(397,877)	-65.11%	-64.06%	-60.57%	-93.02%	-33.27%	-32.99%	-31.68%	-31.12%	-32.93%	-33.06%
2011	600,195	-	570,644	(570,644)	-95.08%	-79.96%	-74.47%	-69.64%	-93.47%	-38.23%	-37.82%	-36.40%	-35.80%	-37.28%
2012	550,748	359,943	834,043	(474,100)	-86.08%	-90.77%	-81.87%	-77.20%	-72.83%	-92.23%	-41.52%	-41.04%	-39.57%	-38.96%
2013	807,528.00	218,771	617,051	(398,280)	-49.32%	-64.23%	-73.68%	-71.64%	-70.05%	-67.62%	-83.78%	-42.23%	-41.78%	-40.40%
2014	376,866.00	89,037	587,748	(498,711)	-132.33%	-75.73%	-79.02%	-83.15%	-79.41%	-76.71%	-73.69%	-87.87%	-45.92%	-45.39%
2015	652,821.00	114,164	350,716	(236,552)	-36.24%	-71.41%	-61.70%	-67.32%	-72.90%	-71.58%	-70.38%	-68.45%	-81.29%	-45.28%
2016	293,379.00	88,302	901,658	(813,356)	-277.24%	-110.96%	-117.05%	-91.38%	-90.29%	-91.17%	-87.08%	-83.96%	-80.79%	-91.90%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Structures & Improvements
Account 390
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	8,368	562	4,542	(3,980)	-47.56%									
1951	17,051	21	7,873	(7,852)	-46.05%	-46.55%								
1952	48,689	1,703	19,553	(17,850)	-36.66%	-39.10%	-40.05%							
1953	39,826	11,725	4,665	7,060	17.73%	-12.19%	-17.66%	-19.86%						
1954	170,321	21,151	16,302	4,849	2.85%	5.67%	-2.30%	-5.00%	-6.25%					
1955	15,097	1,360	20,247	(18,887)	-125.10%	-7.57%	-3.10%	-9.06%	-11.23%	-12.25%				
1956	19,329	2,974	2,005	969	5.01%	-52.05%	-6.38%	-2.46%	-8.14%	-10.22%	-11.20%			
1957	27,144	198	6,831	(6,633)	-24.44%	-12.19%	-39.87%	-8.50%	-4.65%	-9.52%	-11.36%	-12.24%		
1958	14,118	330	4,361	(4,031)	-28.55%	-25.84%	-16.00%	-37.76%	-9.65%	-5.83%	-10.32%	-12.05%	-12.88%	
1959	184,559	13,742	92,612	(78,870)	-42.73%	-41.73%	-39.65%	-36.13%	-41.29%	-23.83%	-20.31%	-21.84%	-22.61%	-23.00%
1960	38,326	5,016	4,632	384	1.00%	-35.21%	-34.82%	-33.75%	-31.11%	-35.86%	-21.80%	-18.71%	-20.27%	-21.04%
1961	3,018,865	801,784	239	801,545	26.55%	26.23%	22.30%	22.08%	21.70%	21.60%	20.93%	20.05%	20.02%	19.25%
1962	4,983	-	2,969	(2,969)	-59.58%	26.41%	26.09%	22.18%	21.96%	21.58%	21.48%	20.81%	19.94%	19.91%
1963	16,456	2,115	6,274	(4,159)	-25.27%	-33.25%	26.13%	25.82%	21.94%	21.72%	21.34%	21.25%	20.59%	19.73%
1964	58,623	1,219	5,201	(3,982)	-6.79%	-10.84%	-13.88%	25.51%	25.21%	21.43%	21.22%	20.85%	20.76%	20.11%
1965	138,600	10	840	(830)	-0.60%	-2.44%	-4.20%	-5.46%	24.39%	24.12%	20.55%	20.35%	20.00%	19.92%
1966	9,482	57	1,297	(1,240)	-13.08%	-1.40%	-2.93%	-4.58%	-5.78%	24.28%	24.01%	20.46%	20.26%	19.91%
1967	3,590	42	507	(465)	-12.95%	-13.04%	-1.67%	-3.10%	-4.71%	-5.89%	24.24%	23.97%	20.42%	20.23%
1968	38,389	-	16,611	(16,611)	-43.27%	-40.68%	-35.59%	-10.07%	-9.30%	-10.29%	-11.20%	23.45%	23.19%	19.73%
1969	4,894	28	10,469	(10,441)	-213.34%	-62.50%	-58.71%	-51.03%	-15.18%	-13.24%	-13.97%	-14.80%	23.10%	22.84%
1970	80,081	4	2,009	(2,005)	-2.50%	-14.65%	-23.55%	-23.25%	-22.55%	-11.49%	-10.66%	-11.35%	-12.03%	22.49%
1971	223,260	1,190	14,412	(13,222)	-5.92%	-5.02%	-8.33%	-12.20%	-12.21%	-12.23%	-8.99%	-8.76%	-9.24%	-9.67%
1972	9,972	92,338	2,730	89,608	898.60%	32.75%	23.74%	20.09%	13.27%	13.01%	12.34%	8.81%	7.20%	6.28%
1973	182,754	91,086	3,279	87,807	48.05%	92.06%	39.47%	32.69%	30.29%	25.06%	24.80%	24.15%	19.19%	17.16%
1974	19,416	(250)	2,019	(2,269)	-11.69%	42.31%	82.56%	37.19%	31.02%	28.72%	23.78%	23.54%	22.94%	18.35%
1975	48,158	1,141	4,161	(3,020)	-6.27%	-7.83%	32.96%	66.13%	32.86%	27.84%	25.76%	21.39%	21.19%	20.67%
1976	69,932	-	10,371	(10,371)	-14.83%	-11.34%	-11.39%	22.53%	48.98%	26.84%	23.13%	21.31%	17.65%	17.49%
1977	42,429	14,997	17,385	(2,388)	-5.63%	-11.36%	-9.83%	-10.03%	19.23%	42.76%	24.52%	21.32%	19.64%	16.28%
1978	186,485	75,155	3,055	72,100	38.66%	30.45%	19.86%	16.23%	14.75%	25.83%	41.40%	27.89%	25.07%	23.73%
1979	29,138	1,986	2,767	(781)	-2.68%	33.08%	26.71%	17.85%	14.77%	13.47%	24.39%	39.21%	26.80%	24.16%
1980	6,370	-	7,709	(7,709)	-121.02%	-23.91%	28.65%	23.15%	15.21%	12.50%	11.34%	22.81%	37.50%	25.65%
1981	173,834	111,604	18,817	92,787	53.38%	47.21%	40.27%	39.51%	35.14%	28.26%	25.28%	24.03%	29.82%	41.09%
1982	14,412	761	42,927	(42,166)	-292.58%	26.89%	22.05%	18.83%	27.84%	24.71%	19.42%	17.25%	16.30%	23.80%
1983	98,647	84,795	18,951	65,844	66.75%	20.94%	40.60%	37.08%	33.49%	35.39%	32.23%	26.93%	24.54%	23.52%
1984	54,190	-	156,565	(156,565)	-288.92%	-59.36%	-79.45%	-11.76%	-13.76%	-12.90%	4.18%	3.49%	1.59%	1.07%
1985	57,917	29,112	31,629	(2,517)	-4.35%	-141.90%	-44.24%	-60.14%	-10.68%	-12.41%	-11.76%	3.38%	2.80%	1.12%
1986	52,461	175	51,635	(51,460)	-98.09%	-48.90%	-127.94%	-54.97%	-67.31%	-20.84%	-22.23%	-21.06%	-4.52%	-4.59%
1987	143,639	19	24,340	(24,321)	-16.93%	-38.64%	-30.82%	-76.20%	-41.54%	-50.13%	-19.90%	-20.97%	-20.12%	-6.71%
1988	56,321	3,758	19,941	(16,183)	-28.73%	-20.26%	-36.43%	-30.44%	-68.87%	-39.99%	-47.61%	-20.66%	-21.63%	-20.83%
1989	88,645	-	8,541	(8,541)	-9.64%	-17.06%	-16.99%	-29.47%	-25.82%	-57.28%	-35.11%	-41.66%	-19.34%	-20.21%
1990	380,465	341,363	49,050	292,313	76.83%	60.49%	50.93%	36.36%	26.58%	24.29%	3.93%	10.57%	5.96%	13.31%
1991	97,856	(1,666)	27,014	(28,680)	-29.31%	55.12%	44.99%	38.33%	27.98%	19.91%	18.31%	0.43%	6.78%	2.65%
1992	28,292	8,252	562	7,690	27.18%	-16.64%	53.56%	44.15%	37.85%	27.95%	20.15%	18.58%	1.22%	7.33%
1993	3,657	500	139,211	(138,711)	-3793.03%	-410.09%	-123.03%	25.99%	20.72%	16.47%	10.46%	3.77%	3.25%	-13.18%
1994	27,352	(140)	1,474	(1,614)	-5.90%	-452.53%	-223.66%	-102.65%	24.37%	19.55%	15.57%	9.92%	3.47%	2.99%
1995	2,121,264	181,208	118,450	62,758	2.96%	2.85%	-3.60%	-3.20%	-4.33%	7.29%	6.74%	6.03%	4.91%	3.11%
1996	100,921	1,353,834	-	1,353,834	1341.48%	63.75%	62.90%	56.64%	56.28%	52.76%	56.08%	54.03%	52.43%	49.16%
1997	47,802	-	-	0	0.00%	910.31%	62.41%	61.59%	55.47%	55.12%	51.72%	55.12%	53.14%	51.58%
1998	436,461	(33,522)	-	(33,522)	-7.68%	-6.92%	225.62%	51.10%	50.53%	45.40%	45.21%	42.66%	46.67%	45.17%
1999	11,020	(5,000)	-	(5,000)	-45.37%	-8.61%	-7.78%	220.61%	50.71%	50.15%	45.03%	44.85%	42.33%	46.36%
2000	183,259	(89,376)	-	(89,376)	-48.77%	-48.58%	-20.28%	-18.85%	157.28%	44.43%	43.96%	39.17%	39.06%	36.87%
2001	7,625	-	19,756	(19,756)	-259.09%	-57.17%	-56.53%	-23.13%	-21.52%	153.25%	43.63%	43.17%	38.40%	38.29%
2002	-	-	-	0	NA	-259.09%	-57.17%	-56.53%	-23.13%	-21.52%	153.25%	43.63%	43.17%	38.40%
2003	-	-	-	0	NA	NA	-259.09%	-57.17%	-56.53%	-23.13%	-21.52%	153.25%	43.63%	43.17%
2004	-	-	-	0	NA	NA	NA	-259.09%	-57.17%	-56.53%	-23.13%	-21.52%	153.25%	43.63%
2005	13,252	-	-	0	0.00%	0.00%	0.00%	0.00%	-94.63%	-53.46%	-53.05%	-22.66%	-21.11%	150.71%
2006	75,451	-	37,835	(37,835)	-50.15%	-42.65%	-42.65%	-42.65%	-42.65%	-59.79%	-52.57%	-52.29%	-25.51%	-23.94%
2007	370,702	-	101,088	(101,088)	-27.27%	-31.14%	-30.24%	-30.24%	-30.24%	-30.24%	-33.98%	-38.15%	-38.27%	-26.11%
2008	108,034	-	14,085	(14,085)	-13.04%	-24.06%	-27.61%	-26.96%	-26.96%	-26.96%	-26.96%	-30.04%	-34.57%	-34.72%
2009	-	-	-	0	NA	-13.04%	-24.06%	-27.61%	-26.96%	-26.96%	-26.96%	-26.96%	-30.04%	-34.57%
2010	60,021	9,266	101	9,166	15.27%	15.27%	-2.93%	-19.68%	-23.42%	-22.92%	-22.92%	-22.92%	-22.92%	-25.76%
2011	226,373	-	276,268	(276,268)	-122.04%	-93.26%	-93.26%	-71.29%	-49.96%	-49.98%	-49.20%	-49.20%	-49.20%	-49.20%
2012	790,840	-	401,976	(401,976)	-50.83%	-66.68%	-62.11%	-62.11%	-57.64%	-50.40%	-50.39%	-49.98%	-49.98%	-49.98%
2013	3,173,978	-	275,876	(275,876)	-8.69%	-17.10%	-22.76%	-22.23%	-22.23%	-22.00%	-22.41%	-22.85%	-22.79%	-22.79%
2014	649,654	-	160,606	(160,606)	-24.72%	-11.42%	-18.17%	-23.03%	-22.56%	-22.56%	-22.35%	-22.69%	-23.07%	-23.02%
2015	1,474,613	127,990	160,947	(32,957)	-2.23%	-9.11%	-8.86%	-14.31%	-18.17%	-17.86%	-17.86%	-17.78%	-18.29%	-18.64%
2016	373,209	-	142,899	(142,899)	-38.29%	-9.52%	-13.47%	-10.80%	-15.70%	-19.30%	-18.99%	-18.99%	-18.89%	-19.32%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Office Furniture & Equipment
Account 391
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	102,809			0	0.00%	0.00%	0.00%	0.00%						
2004	173,148			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	878,542			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	6,886			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	44,975			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	2,279,663	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	318,903	-	44,017	(44,017)	-13.80%	-1.69%	-1.69%	-1.69%	-1.67%	-1.66%	-1.66%	-1.25%	-1.19%	-1.16%
2013	69,718	-	448	(448)	-0.64%	-11.44%	-1.67%	-1.67%	-1.67%	-1.64%	-1.63%	-1.63%	-1.24%	-1.18%
2014	-	-	4,528	(4,528)	NA	-7.14%	-12.61%	-1.84%	-1.84%	-1.84%	-1.81%	-1.80%	-1.80%	-1.36%
2015	527,953	-	-	0	0.00%	-0.86%	-0.83%	-5.35%	-1.53%	-1.53%	-1.53%	-1.51%	-1.51%	-1.51%
2016	167,132	-	-	0	0.00%	0.00%	-0.65%	-0.65%	-4.52%	-1.46%	-1.46%	-1.46%	-1.44%	-1.43%

Xcel Energy Electric Plant
General Network Equipment
Account 391
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	16,391,725			0	0.00%	0.00%	0.00%	0.00%						
2004	3,665,195			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	3,406,259			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	1,371,227			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	2,157,135			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	317,956			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	141,404			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	5,220,532	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	5,878,931	-	2,012	(2,012)	-0.03%	-0.02%	-0.02%	-0.02%	-0.02%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
2013	1,096,352	-	500	(500)	-0.05%	-0.04%	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%	-0.01%	-0.01%
2014	2,792,103	-	-	0	0.00%	-0.01%	-0.03%	-0.02%	-0.02%	-0.02%	-0.02%	-0.01%	-0.01%	-0.01%
2015	174,104	-	54,922	(54,922)	-31.55%	-1.85%	-1.36%	-0.58%	-0.38%	-0.38%	-0.38%	-0.37%	-0.32%	-0.30%
2016	2,576,703	-	-	0	0.00%	-2.00%	-0.99%	-0.83%	-0.46%	-0.32%	-0.32%	-0.32%	-0.32%	-0.28%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Transportation Equipment - Automobiles
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	-			0	NA	NA	NA	NA	NA					
2005	-			0	NA	NA	NA	NA	NA	NA				
2006	-			0	NA	NA	NA	NA	NA	NA	NA			
2007	-			0	NA	NA	NA	NA	NA	NA	NA	NA		
2008	-			0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	-			0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	8,718	-		0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	-	55,724		55,724	NA	639.18%	639.18%	639.18%	639.18%	639.18%	639.18%	639.18%	639.18%	639.18%

Xcel Energy Electric Plant
General Transportation Equipment - Light Trucks
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	288,226			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	37,508		(5,114)	5,114	13.63%	13.63%	1.57%	1.57%	1.57%	1.57%	1.57%			
2007	-			0	NA	13.63%	13.63%	1.57%	1.57%	1.57%	1.57%	1.57%		
2008	-			0	NA	NA	13.63%	13.63%	1.57%	1.57%	1.57%	1.57%	1.57%	
2009	-			0	NA	NA	NA	13.63%	13.63%	1.57%	1.57%	1.57%	1.57%	1.57%
2010	-	-	-	0	NA	NA	NA	NA	13.63%	13.63%	1.57%	1.57%	1.57%	1.57%
2011	-	-	-	0	NA	NA	NA	NA	NA	13.63%	13.63%	1.57%	1.57%	1.57%
2012				0	NA	NA	NA	NA	NA	NA	13.63%	13.63%	1.57%	1.57%
2013				0	NA	NA	NA	NA	NA	NA	NA	13.63%	13.63%	1.57%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	13.63%	13.63%
2015	57,114	16,243	(12,529)	28,772	50.38%	50.38%	50.38%	50.38%	50.38%	50.38%	50.38%	50.38%	50.38%	35.81%
2016	653,030	387,136	-	387,136	59.28%	58.57%	58.57%	58.57%	58.57%	58.57%	58.57%	58.57%	58.57%	58.57%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Transportation Equipment - Trailers
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	795,516			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	10,448			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	17,000		(2,948)	2,948	17.34%	10.74%	0.36%	0.36%	0.36%	0.36%	0.36%			
2007	-			0	NA	17.34%	10.74%	0.36%	0.36%	0.36%	0.36%	0.36%		
2008	-			0	NA	NA	17.34%	10.74%	0.36%	0.36%	0.36%	0.36%	0.36%	
2009	347,741		50	(50)	-0.01%	-0.01%	-0.01%	0.79%	0.77%	0.25%	0.25%	0.25%	0.25%	0.25%
2010	-	-	-	0	NA	-0.01%	-0.01%	-0.01%	0.79%	0.77%	0.25%	0.25%	0.25%	0.25%
2011	-	-	-	0	NA	NA	-0.01%	-0.01%	-0.01%	0.79%	0.77%	0.25%	0.25%	0.25%
2012				0	NA	NA	NA	-0.01%	-0.01%	-0.01%	0.79%	0.77%	0.25%	0.25%
2013				0	NA	NA	NA	NA	-0.01%	-0.01%	-0.01%	0.79%	0.77%	0.25%
2014				0	NA	NA	NA	NA	NA	-0.01%	-0.01%	-0.01%	0.79%	0.77%
2015	38,497	17,009	(25,923)	42,932	111.52%	111.52%	111.52%	111.52%	111.52%	111.52%	11.10%	11.10%	11.10%	11.37%
2016	30,514	407,078	-	407,078	1334.07%	652.08%	652.08%	652.08%	652.08%	652.08%	652.08%	107.97%	107.97%	107.97%

Xcel Energy Electric Plant
General Transportation Equipment - Heavy Trucks
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	11,702,759			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	1,396	(1,396)	NA	NA	NA	NA	NA	NA	-0.01%	-0.01%	-0.01%	-0.01%
2011	-	-	1,318	(1,318)	NA	NA	NA	NA	NA	NA	NA	-0.02%	-0.02%	-0.02%
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	-0.02%	-0.02%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-0.02%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	-	45,063	(35,336)	80,399	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	-	1,589,313	-	1,589,313	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Stores Equipment
Account 393
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	2,370			0	0.00%	0.00%	0.00%							
2003	262,619			0	0.00%	0.00%	0.00%	0.00%						
2004	122,766			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	312,985			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	707,060	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	261,474	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	66,914	-	(2,508)	2,508	3.75%	0.76%	0.76%	0.24%	0.24%	0.24%	0.24%	0.19%	0.19%	0.19%
2015	57,769	-	-	0	0.00%	2.01%	0.65%	0.65%	0.23%	0.23%	0.23%	0.23%	0.18%	0.18%
2016	75,371	-	-	0	0.00%	0.00%	1.25%	0.54%	0.54%	0.21%	0.21%	0.21%	0.21%	0.17%

Xcel Energy Electric Plant
General Tools, Shop & Garage Equipment
Account 394
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	959,246			0	0.00%	0.00%	0.00%							
2003	592,001			0	0.00%	0.00%	0.00%	0.00%						
2004	1,441,978			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	1,768,422			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	20,819		(5)	5	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	7,705,069			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	2,283,581		1,050	(1,050)	-0.05%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	
2009	5,215,159		(0)	0	0.00%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
2010	-	-	-	0	NA	0.00%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%
2011	2,914,764	-	11,284	(11,284)	-0.39%	-0.39%	-0.14%	-0.12%	-0.07%	-0.07%	-0.06%	-0.06%	-0.06%	-0.05%
2012	1,019,225	384	(5,648)	6,032	0.59%	-0.13%	-0.13%	-0.06%	-0.06%	-0.03%	-0.03%	-0.03%	-0.03%	-0.03%
2013	1,884,820		12,921	(12,921)	-0.69%	-0.24%	-0.31%	-0.31%	-0.16%	-0.14%	-0.09%	-0.09%	-0.08%	-0.08%
2014	919,705		18,037	(18,037)	-1.96%	-1.10%	-0.65%	-0.54%	-0.54%	-0.30%	-0.26%	-0.17%	-0.17%	-0.16%
2015	3,325,572			0	0.00%	-0.42%	-0.51%	-0.35%	-0.36%	-0.36%	-0.24%	-0.21%	-0.15%	-0.15%
2016	2,209,131			0	0.00%	0.00%	-0.28%	-0.37%	-0.27%	-0.30%	-0.30%	-0.21%	-0.19%	-0.14%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Laboratory Equipment
Account 395
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	2,490,202			0	0.00%	0.00%	0.00%							
2003	1,818,219			0	0.00%	0.00%	0.00%	0.00%						
2004	1,449,240			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	236,767			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	637,170			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	566,020			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	601,436			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	372,410			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	1,341,983	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	157,716			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	308,567			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	892,983			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	283,177	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	474,723	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Electric Plant
General Power Operated Equipment
Account 396
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	1,757,950			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	3,419			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012			6,805	(6,805)	NA	NA	NA	NA	-199.02%	-199.02%	-199.02%	-199.02%	-0.39%	-0.39%
2013				0	NA	NA	NA	NA	NA	-199.02%	-199.02%	-199.02%	-199.02%	-0.39%
2014				0	NA	NA	NA	NA	NA	NA	-199.02%	-199.02%	-199.02%	-199.02%
2015	52,719	65,252	(35,816)	101,068	191.71%	191.71%	191.71%	178.80%	178.80%	178.80%	178.80%	167.91%	167.91%	167.91%
2016	828,369	2,414,653		2,414,653	291.49%	285.52%	285.52%	285.52%	284.75%	284.75%	284.75%	284.75%	283.65%	283.65%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Communication Equipment
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	1,725			0	0.00%	0.00%								
2002	3,048,699			0	0.00%	0.00%	0.00%							
2003	4,493,608			0	0.00%	0.00%	0.00%	0.00%						
2004	-			0	NA	0.00%	0.00%	0.00%	0.00%					
2005	1,250,459			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	1,034,055			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	154,493			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	307,626			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	268,137			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-		-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	1,333		6,635	(6,635)	-497.63%	-497.63%	-2.46%	-1.15%	-0.91%	-0.38%	-0.22%	-0.22%	-0.09%	-0.06%
2012	337,112		3,561	(3,561)	-1.06%	-3.01%	-3.01%	-1.68%	-1.12%	-0.95%	-0.48%	-0.30%	-0.30%	-0.13%
2013	119,530		455	(455)	-0.38%	-0.88%	-2.33%	-2.33%	-1.47%	-1.03%	-0.90%	-0.48%	-0.31%	-0.31%
2014	512,066			0	0.00%	-0.07%	-0.41%	-1.10%	-1.10%	-0.86%	-0.69%	-0.63%	-0.39%	-0.27%
2015	128,665			0	0.00%	0.00%	-0.06%	-0.37%	-0.97%	-0.97%	-0.78%	-0.64%	-0.58%	-0.37%
2016	59,926			0	0.00%	0.00%	0.00%	-0.06%	-0.35%	-0.92%	-0.92%	-0.75%	-0.61%	-0.56%

Xcel Energy Electric Plant
General Communication Equipment - AES
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002	495,151			0	0.00%	0.00%	0.00%							
2003	135,108			0	0.00%	0.00%	0.00%	0.00%						
2004	192,849			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	466,761			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	16,505			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	98,210			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	193,513	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	19,682			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	-	-	(35,336)	35,336	NA	NA	179.53%	179.53%	16.57%	16.57%	11.35%	11.35%	10.78%	4.45%
2016	147,907	-	-	0	0.00%	23.89%	23.89%	21.08%	21.08%	9.79%	9.79%	7.69%	7.69%	7.43%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Electric Plant
General Communication Equipment - EMS
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002	495,151			0	0.00%	0.00%	0.00%							
2003	135,108			0	0.00%	0.00%	0.00%	0.00%						
2004	192,849			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	466,761			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	16,505			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	98,210			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	193,513	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	19,682	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	147,907	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Electric Plant
General Miscellaneous Equipment
Account 398
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	265,784			0	0.00%	0.00%	0.00%							
2003	-			0	NA	0.00%	0.00%	0.00%						
2004	5,643			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	27,038			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	22,629			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	4,327			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	84,227			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	58,129			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-	-	9,876	(9,876)	NA	NA	NA	-16.99%	-6.94%	-6.73%	-5.83%	-5.03%	-4.89%	-4.89%
2013	13,712	-	-	0	0.00%	-72.02%	-72.02%	-72.02%	-13.75%	-6.33%	-6.16%	-5.40%	-4.70%	-4.58%
2014	-	-	-	0	NA	0.00%	-72.02%	-72.02%	-72.02%	-13.75%	-6.33%	-6.16%	-5.40%	-4.70%
2015	11,893	-	(1)	1	0.01%	0.01%	0.00%	-38.57%	-38.57%	-38.57%	-11.79%	-5.88%	-5.73%	-5.07%
2016	142,970	-	-	0	0.00%	0.00%	0.00%	0.00%	-5.86%	-5.86%	-5.86%	-4.36%	-3.18%	-3.13%
				0	NA	0.00%	0.00%	0.00%	0.00%	-5.86%	-5.86%	-5.86%	-4.36%	-3.18%

NA - Not applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Transmission Structures & Improvements
Account 366
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	-	-	0	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	-	0	NA	NA	NA							
1953	-	-	-	0	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1958	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1973	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	1,659	180	21	159	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%
1976	-	-	-	0	NA	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%
1977	-	-	-	0	NA	NA	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%
1978	6,622	-	-	0	0.00%	0.00%	0.00%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%
1979	19,847	2,375	10,784	(8,409)	-42.37%	-31.77%	-31.77%	-31.77%	-29.33%	-29.33%	-29.33%	-29.33%	-29.33%	-29.33%
1980	149	-	2,010	(2,010)	-1348.99%	-52.11%	-39.14%	-39.14%	-39.14%	-36.28%	-36.28%	-36.28%	-36.28%	-36.28%
1981	-	-	-	0	NA	-1348.99%	-52.11%	-39.14%	-39.14%	-39.14%	-36.28%	-36.28%	-36.28%	-36.28%
1982	-	-	-	0	NA	NA	-1348.99%	-52.11%	-39.14%	-39.14%	-39.14%	-36.28%	-36.28%	-36.28%
1983	-	-	-	0	NA	NA	NA	-1348.99%	-52.11%	-39.14%	-39.14%	-39.14%	-36.28%	-36.28%
1984	-	-	-	0	NA	NA	NA	NA	-1348.99%	-52.11%	-39.14%	-39.14%	-39.14%	-36.28%
1985	-	-	73	(73)	NA	NA	NA	NA	NA	-1397.99%	-52.47%	-39.42%	-39.42%	-39.42%
1986	-	-	-	0	NA	NA	NA	NA	NA	NA	-1397.99%	-52.47%	-39.42%	-39.42%
1987	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-1397.99%	-52.47%	-39.42%
1988	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	-1397.99%	-52.47%
1989	20,340	-	-	0	0.00%	0.00%	0.00%	0.00%	-0.36%	-0.36%	-0.36%	-0.36%	-0.36%	-10.17%
1990	-	13,140	-	13,140	NA	64.60%	64.60%	64.60%	64.60%	64.24%	64.24%	64.24%	64.24%	64.24%
1991	-	-	-	0	NA	NA	64.60%	64.60%	64.60%	64.60%	64.24%	64.24%	64.24%	64.24%
1992	2,145	-	2,101	(2,101)	-97.95%	-97.95%	514.64%	49.09%	49.09%	49.09%	49.09%	48.77%	48.77%	48.77%
1993	-	-	-	0	NA	-97.95%	-97.95%	514.64%	49.09%	49.09%	49.09%	49.09%	48.77%	48.77%
1994	-	-	-	0	NA	NA	-97.95%	-97.95%	514.64%	49.09%	49.09%	49.09%	49.09%	48.77%
1995	560	-	-	0	0.00%	0.00%	0.00%	-77.67%	-77.67%	408.10%	47.90%	47.90%	47.90%	47.90%
1996	-	-	-	0	NA	0.00%	0.00%	0.00%	-77.67%	-77.67%	408.10%	47.90%	47.90%	47.90%
1997	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	-77.67%	-77.67%	408.10%	47.90%	47.90%
1998	5,402	-	264	(264)	-4.89%	-4.89%	-4.89%	-4.43%	-4.43%	-4.43%	-29.17%	-29.17%	132.91%	37.88%
1999	-	-	-	0	NA	-4.89%	-4.89%	-4.89%	-4.43%	-4.43%	-4.43%	-29.17%	-29.17%	132.91%
2000	-	(3,674)	-	(3,674)	NA	NA	-72.90%	-72.90%	-72.90%	-66.05%	-66.05%	-66.05%	-74.49%	-74.49%
2001	-	-	-	0	NA	NA	NA	-72.90%	-72.90%	-72.90%	-66.05%	-66.05%	-66.05%	-74.49%
2002	-	-	-	0	NA	NA	NA	NA	-72.90%	-72.90%	-72.90%	-66.05%	-66.05%	-66.05%
2003	1,757	-	-	0	0.00%	0.00%	0.00%	-209.16%	-209.16%	-55.01%	-55.01%	-55.01%	-51.02%	-51.02%
2004	-	-	-	0	NA	0.00%	0.00%	0.00%	-209.16%	-209.16%	-55.01%	-55.01%	-55.01%	-51.02%
2005	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	-209.16%	-209.16%	-55.01%	-55.01%	-55.01%
2006	22,284	-	3,885	(3,885)	-17.43%	-17.43%	-17.43%	-16.16%	-16.16%	-16.16%	-31.44%	-31.44%	-26.57%	-26.57%
2007	11,909	-	-	0	0.00%	-11.36%	-11.36%	-11.36%	-10.81%	-10.81%	-10.81%	-21.03%	-21.03%	-18.92%
2008	-	-	-	0	NA	0.00%	-11.36%	-11.36%	-11.36%	-10.81%	-10.81%	-10.81%	-21.03%	-21.03%
2009	-	-	-	0	NA	NA	0.00%	-11.36%	-11.36%	-11.36%	-10.81%	-10.81%	-10.81%	-21.03%
2010	-	-	-	0	NA	NA	NA	0.00%	-11.36%	-11.36%	-11.36%	-10.81%	-10.81%	-10.81%
2011	-	-	-	0	NA	NA	NA	NA	0.00%	-11.36%	-11.36%	-11.36%	-10.81%	-10.81%
2012	-	-	-	0	NA	NA	NA	NA	NA	0.00%	-11.36%	-11.36%	-11.36%	-10.81%
2013	-	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	-11.36%	-11.36%	-11.36%
2014	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	-11.36%	-11.36%
2015	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	-11.36%
2016	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Transmission Mains
Account 367
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	-	-	0	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	-	0	NA	NA	NA							
1953	-	-	-	0	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1973	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1976	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1977	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1978	2,200	-	2,379	(2,379)	-108.14%	-108.14%	-108.14%	-108.14%	-108.14%	-108.14%	-108.14%	-108.14%	-108.14%	-108.14%
1979	9,171	6,759	-	6,759	73.70%	38.52%	38.52%	38.52%	38.52%	38.52%	38.52%	38.52%	38.52%	38.52%
1980	19,112	-	-	0	0.00%	23.90%	14.37%	14.37%	14.37%	14.37%	14.37%	14.37%	14.37%	14.37%
1981	95,035	540,123	-	540,123	568.34%	473.18%	443.47%	433.80%	433.80%	433.80%	433.80%	433.80%	433.80%	433.80%
1982	1,774	-	3,875	(3,875)	-218.43%	553.92%	462.60%	434.09%	424.71%	424.71%	424.71%	424.71%	424.71%	424.71%
1983	-	62,960	-	62,960	NA	3330.61%	618.96%	516.91%	484.42%	474.18%	474.18%	474.18%	474.18%	474.18%
1984	-	232,019	3,852	228,167	NA	NA	16192.33%	854.65%	713.74%	666.82%	653.42%	653.42%	653.42%	653.42%
1985	44,484	149,522	8,449	141,073	317.13%	830.05%	971.59%	925.95%	685.42%	603.75%	575.09%	566.34%	566.34%	566.34%
1986	-	21,041	7,139	13,902	NA	348.38%	861.30%	1002.84%	956.00%	695.26%	612.42%	583.28%	574.43%	574.43%
1987	2,488	309,491	1,243	308,248	12389.39%	12948.15%	986.17%	1471.92%	1605.96%	1539.56%	897.61%	792.30%	754.00%	743.11%
1988	-	570	-	570	NA	12412.30%	12971.06%	987.38%	1473.13%	1607.17%	1540.73%	898.01%	792.65%	754.33%
1989	-	-	-	0	NA	NA	12412.30%	12971.06%	987.38%	1473.13%	1607.17%	1540.73%	898.01%	792.65%
1990	-	-	3,799	(3,799)	NA	NA	NA	12259.61%	12818.37%	979.29%	1465.05%	1599.08%	1532.94%	895.37%
1991	182,624	192,281	40,932	151,349	82.87%	80.79%	80.79%	81.11%	246.54%	254.05%	266.27%	365.65%	393.07%	388.38%
1992	292,293	-	29,780	(29,780)	-10.19%	25.60%	24.80%	24.80%	24.92%	89.36%	92.27%	111.43%	155.15%	167.22%
1993	-	155,991	204	155,787	NA	43.11%	58.40%	57.60%	57.60%	57.72%	121.99%	124.90%	141.28%	185.00%
1994	425,292	-	36,927	(36,927)	-8.68%	27.95%	12.41%	26.71%	26.29%	26.29%	26.35%	60.42%	61.96%	73.95%
1995	-	(155,991)	3,540	(159,531)	NA	-46.19%	-9.56%	-9.82%	8.99%	8.56%	8.56%	8.63%	42.75%	44.29%
1996	-	347,925	12,909	335,016	NA	NA	32.58%	69.21%	36.87%	46.20%	45.78%	45.78%	45.84%	79.86%
1997	20,566	83,015	-	83,015	403.65%	2032.63%	1256.93%	49.70%	84.64%	47.09%	54.19%	53.77%	53.77%	53.84%
1998	-	-	-	0	NA	403.65%	2032.63%	1256.93%	49.70%	84.64%	47.09%	54.19%	53.77%	53.77%
1999	-	-	-	0	NA	NA	403.65%	2032.63%	1256.93%	49.70%	84.64%	47.09%	54.19%	53.77%
2000	9,809	(22,780)	(81,140)	58,360	594.96%	594.96%	594.96%	465.43%	1568.37%	1043.16%	61.43%	95.62%	54.27%	59.89%
2001	24,255	-	15,956	(15,956)	-65.78%	124.48%	124.48%	124.48%	229.58%	842.82%	550.80%	55.00%	87.47%	50.50%
2002	-	-	-	0	NA	-65.78%	124.48%	124.48%	124.48%	229.58%	842.82%	550.80%	55.00%	87.47%
2003	37,754	-	-	0	0.00%	0.00%	-25.73%	59.04%	59.04%	59.04%	135.76%	498.40%	325.71%	50.99%
2004	-	-	-	0	NA	0.00%	0.00%	-25.73%	59.04%	59.04%	59.04%	135.76%	498.40%	325.71%
2005	346,129	-	-	0	0.00%	0.00%	0.00%	0.00%	-3.91%	10.15%	10.15%	10.15%	28.60%	105.00%
2006	30,760	13,106	22,402	(9,296)	-30.22%	-2.47%	-2.47%	-2.24%	-2.24%	-5.75%	7.38%	7.38%	7.38%	24.75%
2007	118,421	52,698	7,628	45,070	38.06%	23.98%	7.22%	7.22%	6.71%	6.71%	3.56%	13.78%	13.78%	13.78%
2008	-	-	-	0	NA	38.06%	23.98%	7.22%	7.22%	6.71%	6.71%	3.56%	13.78%	13.78%
2009	-	-	-	0	NA	NA	38.06%	23.98%	7.22%	7.22%	6.71%	6.71%	3.56%	13.78%
2010	-	-	-	0	NA	NA	NA	38.06%	23.98%	7.22%	7.22%	6.71%	6.71%	3.56%
2011	670,110	-	228,915	(228,915)	-34.16%	-34.16%	-34.16%	-34.16%	-23.31%	-23.57%	-16.57%	-16.57%	-16.05%	-16.05%
2012	698			0	0.00%	-34.13%	-34.13%	-34.13%	-34.13%	-23.29%	-23.55%	-16.56%	-16.56%	-16.04%
2013	1,612			0	0.00%	0.00%	-34.04%	-34.04%	-34.04%	-34.04%	-23.25%	-23.51%	-16.54%	-16.54%
2014	1,523,206		1,420,195	(1,420,195)	-93.24%	-93.14%	-93.10%	-75.11%	-75.11%	-75.11%	-75.11%	-69.32%	-68.80%	-59.95%
2015	1,276		56,357	(56,357)	-4416.69%	-96.86%	-96.75%	-96.71%	-77.63%	-77.63%	-77.63%	-77.63%	-71.71%	-71.17%
2016	816,534		55,751	(55,751)	-6.83%	-13.71%	-65.45%	-65.41%	-65.39%	-58.45%	-58.45%	-58.45%	-58.45%	-54.80%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Transmission Measure and Regulating Station Equipment
Account 369
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	-	-	0	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	-	0	NA	NA	NA							
1953	-	-	-	0	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1973	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	5,418	635	73	562	10.37%	10.37%	10.37%	10.37%	10.37%	10.37%	10.37%	10.37%	10.37%	10.37%
1976	-	-	505	(505)	NA	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%	1.05%
1977	3,885	-	-	0	0.00%	-13.00%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
1978	33,212	674	352	322	0.97%	0.87%	-0.49%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%
1979	101,335	17,943	20,118	(2,175)	-2.15%	-1.38%	-1.34%	-1.70%	-1.25%	-1.25%	-1.25%	-1.25%	-1.25%	-1.25%
1980	111,297	2,427	1,062	1,365	1.23%	-0.38%	-0.20%	-0.20%	-0.40%	-0.17%	-0.17%	-0.17%	-0.17%	-0.17%
1981	180,953	24,666	7,336	17,330	9.58%	6.40%	4.20%	3.95%	3.91%	3.79%	3.88%	3.88%	3.88%	3.88%
1982	31,495	-	1,486	(1,486)	-4.72%	7.46%	5.32%	3.54%	3.35%	3.32%	3.21%	3.30%	3.30%	3.30%
1983	3,775	(38)	1,670	(1,708)	-45.25%	-9.06%	6.54%	4.73%	3.11%	2.95%	2.93%	2.82%	2.91%	2.91%
1984	52,154	-	1,533	(1,533)	-2.94%	-5.79%	-5.41%	4.70%	3.68%	2.45%	2.36%	2.34%	2.24%	2.33%
1985	-	-	513	(513)	NA	-3.92%	-6.71%	-5.99%	4.50%	3.54%	2.35%	2.26%	2.24%	2.14%
1986	-	-	-	0	NA	NA	-3.92%	-6.71%	-5.99%	4.50%	3.54%	2.35%	2.26%	2.24%
1987	-	-	-	0	NA	NA	NA	-3.92%	-6.71%	-5.99%	4.50%	3.54%	2.35%	2.26%
1988	5,170	-	-	0	0.00%	0.00%	0.00%	-9.92%	-3.57%	-6.14%	-5.66%	4.42%	3.50%	2.32%
1989	107,274	-	-	0	0.00%	0.00%	0.00%	0.00%	-0.46%	-1.24%	-2.23%	-2.62%	3.17%	2.73%
1990	3,574	69,016	-	69,016	1931.06%	62.26%	59.49%	59.49%	59.49%	59.05%	39.82%	37.95%	31.35%	21.10%
1991	9,712	-	1,855	(1,855)	-19.10%	505.50%	55.71%	53.42%	53.42%	53.42%	53.01%	36.61%	34.90%	29.05%
1992	9,661	-	(580)	580	6.00%	-6.58%	295.21%	52.02%	50.03%	50.03%	50.03%	49.65%	35.03%	33.45%
1993	8,740	-	-	0	0.00%	3.15%	-4.54%	213.78%	48.75%	47.00%	47.00%	47.00%	46.64%	33.47%
1994	421,740	3,512	-	3,512	0.83%	0.82%	0.93%	0.50%	15.71%	12.71%	12.59%	12.59%	12.59%	12.50%
1995	14,488	-	1,266	(1,266)	-8.74%	0.51%	0.50%	0.62%	0.21%	14.96%	12.17%	12.06%	12.06%	12.06%
1996	1,829	-	-	0	0.00%	-7.76%	0.51%	0.50%	0.62%	0.21%	14.90%	12.13%	12.02%	12.02%
1997	129,294	5,260	-	5,260	4.07%	4.01%	2.74%	1.32%	1.30%	1.38%	1.05%	12.56%	10.65%	10.58%
1998	159,608	-	5,403	(5,403)	-3.39%	-0.05%	-0.05%	-0.46%	0.29%	0.29%	0.36%	0.11%	9.21%	8.07%
1999	13,276	-	3,147	(3,147)	-23.70%	-4.95%	-1.09%	-1.08%	-1.43%	-0.14%	-0.14%	-0.06%	-0.30%	8.64%
2000	10,740	(17,609)	34,025	(51,634)	-480.76%	-228.10%	-32.78%	-17.55%	-17.45%	-17.07%	-7.01%	-6.93%	-6.77%	-6.93%
2001	-	-	-	0	NA	-480.76%	-228.10%	-32.78%	-17.55%	-17.45%	-17.07%	-7.01%	-6.93%	-6.77%
2002	-	-	-	0	NA	NA	-480.76%	-228.10%	-32.78%	-17.55%	-17.45%	-17.07%	-7.01%	-6.93%
2003	2,275	-	-	0	0.00%	0.00%	0.00%	-396.72%	-208.36%	-32.37%	-17.43%	-17.32%	-16.95%	-6.99%
2004	-	-	-	0	NA	0.00%	0.00%	0.00%	-396.72%	-208.36%	-32.37%	-17.43%	-17.32%	-16.95%
2005	1,361	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	-359.16%	-198.11%	-32.14%	-17.35%	-17.25%
2006	130,031	-	71,892	(71,892)	-55.29%	-54.72%	-54.72%	-53.78%	-53.78%	-53.78%	-85.54%	-80.33%	-41.63%	-28.40%
2007	23,421	-	34,658	(34,658)	-147.98%	-69.44%	-68.82%	-68.82%	-67.83%	-67.83%	-67.83%	-94.25%	-89.08%	-48.94%
2008	-	-	-	0	NA	-147.98%	-69.44%	-68.82%	-68.82%	-67.83%	-67.83%	-67.83%	-94.25%	-89.08%
2009	131,357	-	3,056	(3,056)	-2.33%	-2.33%	-24.37%	-38.48%	-38.30%	-38.30%	-38.00%	-38.00%	-38.00%	-53.89%
2010	12,800	-	-	0	0.00%	-2.12%	-2.12%	-22.51%	-36.83%	-36.66%	-36.66%	-36.38%	-36.38%	-36.38%
2011	56,895	-	49,228	(49,228)	-86.52%	-70.63%	-26.01%	-26.01%	-38.73%	-44.80%	-44.63%	-44.63%	-44.35%	-44.35%
2012	96,990	-	-	0	0.00%	-31.99%	-29.53%	-17.54%	-17.54%	-27.05%	-35.18%	-35.07%	-35.07%	-34.90%
2013	28,111	-	155,827	(155,827)	-554.33%	-124.56%	-112.67%	-105.27%	-63.81%	-63.81%	-69.45%	-65.61%	-65.42%	-65.42%
2014	79,135	-	39,033	(39,033)	-49.32%	-181.69%	-95.41%	-93.47%	-89.11%	-60.98%	-60.98%	-65.73%	-63.30%	-63.15%
2015	8,377	-	-	0	0.00%	-44.60%	-168.53%	-91.65%	-90.57%	-86.46%	-59.74%	-59.74%	-64.47%	-62.37%
2016	47,153	-	-	0	0.00%	0.00%	-28.99%	-119.71%	-75.01%	-77.08%	-74.09%	-53.63%	-53.63%	-58.19%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Structures & Improvements
Account 375
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	100	2,048	(1,948)	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	100	(100)	NA	NA	NA							
1953	-	-	21	(21)	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	1	2	(1)	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	184	683	(499)	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	-	43	(43)	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	325	860	(535)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	74	151	(77)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	250	147	103	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	10	115	(105)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	10	(10)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	315	(315)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	5	(5)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	-	165	(165)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1973	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1976	-	250	-	250	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1977	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1978	-	400	-	400	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1979	-	3,947	2,686	1,261	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1980	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1981	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1982	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1983	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1984	918	-	919	(919)	-100.11%	-100.11%	-100.11%	-100.11%	-100.11%	37.25%	80.83%	80.83%	108.06%	108.06%
1985	106	436	-	436	411.32%	-47.17%	-47.17%	-47.17%	-47.17%	-47.17%	75.98%	115.04%	115.04%	139.45%
1986	-	-	-	0	NA	411.32%	-47.17%	-47.17%	-47.17%	-47.17%	-47.17%	75.98%	115.04%	115.04%
1987	-	-	-	0	NA	NA	411.32%	-47.17%	-47.17%	-47.17%	-47.17%	-47.17%	75.98%	115.04%
1988	-	-	-	0	NA	NA	NA	411.32%	-47.17%	-47.17%	-47.17%	-47.17%	-47.17%	75.98%
1989	-	-	-	0	NA	NA	NA	NA	411.32%	-47.17%	-47.17%	-47.17%	-47.17%	-47.17%
1990	-	-	-	0	NA	NA	NA	NA	NA	411.32%	-47.17%	-47.17%	-47.17%	-47.17%
1991	435	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	80.59%	-33.10%	-33.10%	-33.10%
1992	8,491	-	117	(117)	-1.38%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	3.53%	-6.03%	-6.03%
1993	-	-	-	0	NA	-1.38%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	3.53%	-6.03%
1994	3,680	-	365	(365)	-9.92%	-9.92%	-3.96%	-3.82%	-3.82%	-3.82%	-3.82%	-3.82%	-3.82%	-0.36%
1995	-	-	-	0	NA	-9.92%	-9.92%	-3.96%	-3.82%	-3.82%	-3.82%	-3.82%	-3.82%	-3.82%
1996	411	-	-	0	0.00%	0.00%	-8.92%	-8.92%	-3.83%	-3.70%	-3.70%	-3.70%	-3.70%	-3.70%
1997	-	-	-	0	NA	0.00%	0.00%	-8.92%	-8.92%	-3.83%	-3.70%	-3.70%	-3.70%	-3.70%
1998	-	-	-	0	NA	NA	0.00%	0.00%	-8.92%	-8.92%	-3.83%	-3.70%	-3.70%	-3.70%
1999	-	-	-	0	NA	NA	NA	0.00%	0.00%	-8.92%	-8.92%	-3.83%	-3.70%	-3.70%
2000	1,187	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-6.92%	-6.92%	-3.50%	-3.39%
2001	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-6.92%	-6.92%	-3.50%
2002	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-6.92%	-6.92%
2003	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-6.92%
2004	-	-	-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2005	-	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2006	4,392	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2007	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2008	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2009	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2012	4,534	-	2,878	(2,878)	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-32.24%	-32.24%	-32.24%	-32.24%
2013	-	-	-	0	NA	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-32.24%	-32.24%	-32.24%
2014	-	-	-	0	NA	NA	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-32.24%	-32.24%
2015	-	-	-	0	NA	NA	NA	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-32.24%
2016	-	-	-	0	NA	NA	NA	NA	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%	-63.47%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy
Distribution Mains - Metallic
Account 376
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	6,143	752	2,320	(1,568)	-25.52%									
1951	3,621	372	1,165	(793)	-21.90%	-24.18%								
1952	10,066	1,230	3,142	(1,912)	-18.99%	-19.76%	-21.55%							
1953	18,739	501	2,747	(2,246)	-11.99%	-14.43%	-15.27%	-16.90%						
1954	13,390	247	2,407	(2,160)	-16.13%	-13.71%	-14.97%	-15.52%	-16.70%					
1955	25,668	680	2,375	(1,695)	-6.60%	-9.87%	-10.56%	-11.81%	-12.32%	-13.36%				
1956	50,983	1,768	6,963	(5,195)	-10.19%	-8.99%	-10.05%	-10.38%	-11.11%	-11.43%	-12.11%			
1957	53,651	3,886	8,554	(4,668)	-8.70%	-9.43%	-8.87%	-9.55%	-9.83%	-10.36%	-10.60%	-11.10%		
1958	94,547	6,326	12,086	(5,760)	-6.09%	-7.04%	-7.84%	-7.70%	-8.18%	-8.45%	-8.85%	-9.03%	-9.39%	
1959	119,005	9,154	13,232	(4,078)	-3.43%	-4.61%	-5.43%	-6.19%	-6.22%	-6.59%	-6.86%	-7.18%	-7.32%	-7.60%
1960	146,641	25,310	22,017	3,293	2.25%	-0.30%	-1.82%	-2.71%	-3.53%	-3.69%	-4.02%	-4.31%	-4.58%	-4.70%
1961	59,014	3,215	16,481	(13,266)	-22.48%	-4.85%	-4.33%	-4.73%	-5.18%	-5.66%	-5.71%	-5.96%	-6.15%	-6.37%
1962	105,314	1,012	34,265	(33,253)	-31.58%	-28.31%	-13.90%	-11.00%	-10.12%	-9.99%	-10.00%	-9.87%	-9.99%	-10.05%
1963	165,355	1,133	31,716	(30,583)	-18.50%	-23.58%	-23.39%	-15.50%	-13.08%	-12.12%	-11.88%	-11.77%	-11.61%	-11.68%
1964	199,865	2,248	36,039	(33,791)	-16.91%	-17.63%	-20.75%	-20.94%	-15.91%	-14.04%	-13.20%	-12.94%	-12.80%	-12.65%
1965	188,804	1,696	39,089	(37,393)	-19.81%	-18.31%	-18.37%	-20.48%	-20.64%	-16.76%	-15.15%	-14.36%	-14.09%	-13.92%
1966	307,979	2,759	39,904	(37,145)	-12.06%	-15.00%	-15.55%	-16.12%	-17.80%	-18.07%	-15.53%	-14.41%	-13.85%	-13.65%
1967	136,986	2,133	31,927	(29,794)	-21.75%	-15.04%	-16.46%	-16.57%	-16.89%	-18.29%	-18.50%	-16.18%	-15.12%	-14.56%
1968	140,499	2,963	33,968	(31,005)	-22.07%	-21.91%	-16.73%	-17.48%	-17.36%	-17.53%	-18.71%	-18.89%	-16.75%	-15.74%
1969	162,072	2,962	44,867	(41,905)	-25.86%	-24.10%	-23.37%	-18.71%	-18.93%	-18.57%	-18.56%	-19.54%	-19.66%	-17.66%
1970	127,243	59,620	34,220	25,400	19.96%	-5.70%	-11.05%	-13.64%	-13.08%	-14.28%	-14.69%	-15.13%	-16.26%	-16.49%
1971	96,432	33,937	40,958	(7,021)	-7.28%	8.22%	-6.10%	-10.36%	-12.71%	-12.51%	-13.69%	-14.17%	-14.64%	-15.73%
1972	167,132	110,552	35,664	74,888	44.81%	25.75%	23.87%	9.29%	2.94%	-1.14%	-4.09%	-6.33%	-7.71%	-8.77%
1973	149,071	29,344	39,507	(10,163)	-6.82%	20.47%	13.98%	15.39%	5.87%	1.21%	-2.00%	-4.41%	-6.38%	-7.63%
1974	124,281	156,025	32,548	123,477	99.35%	41.45%	42.73%	33.74%	31.10%	19.93%	13.83%	9.41%	4.73%	1.83%
1975	155,197	8,125	69,338	(61,213)	-39.44%	22.28%	12.16%	21.32%	17.33%	17.74%	10.54%	6.46%	3.39%	0.35%
1976	204,890	106,656	126,346	(19,690)	-9.61%	-22.47%	8.79%	5.12%	13.40%	11.18%	12.27%	7.06%	3.98%	1.57%
1977	260,298	16,405	122,659	(106,254)	-40.82%	-27.07%	-30.17%	-8.55%	-8.26%	0.10%	-0.52%	1.51%	-1.55%	-3.37%
1978	323,261	72,133	233,494	(161,361)	-49.92%	-45.86%	-36.44%	-36.93%	-21.07%	-19.33%	-11.58%	-11.30%	-8.83%	-10.39%
1979	318,817	3,804	212,401	(208,597)	-65.43%	-57.62%	-52.77%	-44.79%	-44.13%	-31.27%	-28.90%	-21.66%	-20.89%	-18.19%
1980	387,831	79,920	458,132	(378,212)	-97.52%	-83.04%	-72.64%	-66.22%	-58.47%	-56.68%	-45.75%	-42.73%	-35.73%	-34.48%
1981	825,609	580	367,691	(367,111)	-44.47%	-61.42%	-62.26%	-60.11%	-57.73%	-53.48%	-52.60%	-45.34%	-43.25%	-38.21%
1982	605,121	7,109	329,477	(322,368)	-53.27%	-48.19%	-58.71%	-59.71%	-58.43%	-56.74%	-53.44%	-52.74%	-46.84%	-45.06%
1983	339,003	164,775	178,171	(13,396)	-3.95%	-35.56%	-39.72%	-50.11%	-52.08%	-51.83%	-50.89%	-48.30%	-47.90%	-42.74%
1984	258,818	2,846	141,735	(138,889)	-53.66%	-25.47%	-39.46%	-41.50%	-50.49%	-52.23%	-51.98%	-51.11%	-48.70%	-48.31%
1985	183,413	6,428	137,198	(130,770)	-71.30%	-60.98%	-36.23%	-43.67%	-43.97%	-51.96%	-53.43%	-53.08%	-52.17%	-49.81%
1986	163,111	526,716	230,624	296,092	181.53%	47.71%	4.37%	1.38%	-19.96%	-28.48%	-38.17%	-40.99%	-41.84%	-41.77%
1987	411,428	(241,164)	237,676	(478,840)	-116.38%	-31.81%	-41.36%	-44.49%	-34.36%	-40.19%	-41.46%	-48.31%	-49.87%	-49.88%
1988	356,277	58,599	180,326	(121,727)	-34.17%	-78.23%	-32.71%	-39.06%	-41.81%	-34.32%	-39.27%	-40.63%	-46.88%	-48.42%
1989	397,725	40,142	197,681	(157,539)	-39.61%	-37.04%	-65.05%	-34.78%	-39.21%	-41.32%	-35.32%	-39.32%	-40.52%	-46.15%
1990	605,322	42,383	293,405	(251,022)	-41.47%	-40.73%	-39.01%	-56.99%	-36.87%	-39.85%	-41.36%	-36.69%	-39.71%	-40.66%
1991	686,098	49,050	332,740	(283,690)	-41.35%	-41.40%	-40.98%	-39.80%	-52.62%	-38.04%	-40.22%	-41.36%	-37.63%	-39.99%
1992	1,286,023	4,254	522,481	(518,227)	-40.30%	-40.66%	-40.85%	-40.69%	-39.99%	-48.39%	-38.79%	-40.24%	-41.04%	-38.36%
1993	539,039	(763)	302,029	(302,792)	-56.17%	-44.99%	-43.99%	-43.50%	-43.06%	-42.24%	-49.37%	-40.89%	-42.10%	-42.71%
1994	637,351	1,785	276,351	(274,566)	-43.08%	-49.08%	-44.49%	-43.81%	-43.43%	-43.06%	-42.36%	-48.55%	-41.17%	-42.22%
1995	1,164,725	(5,100)	217,282	(222,382)	-19.09%	-27.58%	-34.16%	-36.34%	-37.13%	-37.67%	-37.81%	-37.58%	-42.91%	-37.05%
1996	316,021	3,653	187,948	(184,295)	-58.32%	-27.46%	-32.16%	-37.03%	-38.10%	-38.58%	-38.91%	-38.96%	-38.68%	-43.67%
1997	379,795	2,859	178,040	(175,181)	-46.13%	-51.66%	-31.27%	-34.29%	-38.17%	-38.80%	-39.15%	-39.40%	-39.42%	-39.12%
1998	1,161,767	96,612	311,185	(214,573)	-18.47%	-25.28%	-30.90%	-26.35%	-29.26%	-32.72%	-34.50%	-35.26%	-35.81%	-36.02%
1999	1,064,354	57,589	35,771	21,818	2.05%	-8.66%	-14.12%	-18.90%	-18.95%	-22.21%	-25.69%	-28.56%	-29.77%	-30.67%
2000	944,891	158,394	94,517	63,877	6.76%	4.27%	-4.06%	-8.56%	-12.63%	-14.13%	-17.38%	-20.75%	-24.10%	-25.55%
2001	644,735	(6)	46,542	(46,548)	-7.22%	1.09%	1.48%	-4.60%	-8.36%	-11.86%	-13.34%	-16.34%	-19.48%	-22.77%
2002	423,962	(2,932)	(189,519)	186,587	44.01%	13.10%	10.13%	7.33%	0.26%	-3.55%	-7.06%	-9.36%	-12.55%	-15.78%
2003	348,764	-	13,959	(13,959)	-4.00%	22.34%	8.89%	8.04%	6.18%	-0.06%	-3.58%	-6.86%	-9.07%	-12.13%
2004	444,145	-	82,638	(82,638)	-18.61%	-12.18%	7.40%	2.33%	3.82%	3.34%	-1.70%	-4.82%	-7.77%	-9.68%
2005	864,678	-	71,486	(71,486)	-8.27%	-11.78%	-10.14%	0.89%	-1.03%	0.98%	1.22%	-2.66%	-5.29%	-7.83%
2006	567,306	-	148,722	(148,722)	-26.22%	-15.38%	-16.14%	-14.24%	-4.92%	-5.37%	-2.66%	-1.72%	-4.73%	-7.03%
2007	283,204	-	130,105	(130,105)	-45.94%	-32.78%	-20.42%	-20.05%	-17.82%	-8.88%	-8.58%	-5.37%	-3.96%	-6.46%
2008	382,030	-	90,419	(90,419)	-23.67%	-33.15%	-29.96%	-21.02%	-20.59%	-18.59%	-10.58%	-10.04%	-6.80%	-5.22%
2009	324,145	-	51,003	(51,003)	-15.73%	-20.03%	-27.44%	-27.00%	-20.31%	-20.04%	-18.30%	-11.04%	-10.47%	-7.35%
2010	986,972	-	140,357	(140,357)	-14.22%	-14.60%	-16.64%	-20.84%	-22.04%	-18.55%	-18.55%	-17.34%	-11.72%	-11.17%
2011	650,594	-	366,488	(366,488)	-56.33%	-30.95%	-28.44%	-27.66%	-29.63%	-29.02%	-24.60%	-24.01%	-22.57%	-17.22%
2012	734,484	75,511	126,580	(51,069)	-6.95%	-30.15%	-23.52%	-22.58%	-22.72%	-24.68%	-24.90%	-21.90%	-21.62%	-20.52%
2013	910,651	74,293	165,990	(91,697)	-10.07%	-8.68%	-22.18%	-19.79%	-19.42%	-19.83%	-21.56%	-22.11%	-20.01%	-19.91%
2014	656,011	248	479,239	(478,991)	-73.02%	-36.43%	-27.02%	-33.48%	-28.65%	-27.67%	-27.34%	-28.41%	-28.18%	-25.48%
2015	1,126,614		353,277	(353,277)	-31.36%	-46.69%	-34.31%	-28.45%	-32.89%	-29.26%	-28.44%	-28.13%	-28.96%	-28.72%
2016	167,127		808,052	(808,052)	-483.50%	-89.77%	-84.13%	-60.55%	-49.60%	-50.63%	-43.76%	-42.13%	-40.94%	-41.17%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Mains - Plastic
Account 376
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	-	-	0	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	-	0	NA	NA	NA							
1953	-	-	-	0	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	(4)	218	(222)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	22,033	64	833	(769)	-3.49%	-4.50%	-4.50%	-4.50%	-4.50%	-4.50%	-4.50%	-4.50%	-4.50%	-4.50%
1971	14,194	1,905	1,559	346	2.44%	-1.17%	-1.78%	-1.78%	-1.78%	-1.78%	-1.78%	-1.78%	-1.78%	-1.78%
1972	14,884	(35)	1,072	(1,107)	-7.44%	-2.62%	-2.99%	-3.43%	-3.43%	-3.43%	-3.43%	-3.43%	-3.43%	-3.43%
1973	24,279	15,117	7,687	7,430	30.60%	16.15%	12.50%	7.83%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%
1974	15,204	45,717	3,461	42,256	277.93%	125.84%	89.35%	71.36%	53.16%	52.91%	52.91%	52.91%	52.91%	52.91%
1975	20,556	5,660	10,552	(4,892)	-23.80%	104.49%	74.61%	58.31%	49.41%	38.92%	38.72%	38.72%	38.72%	38.72%
1976	8,993	21,213	6,258	14,955	166.30%	34.06%	116.91%	86.55%	69.88%	60.12%	48.46%	48.27%	48.27%	48.27%
1977	23,480	(21,232)	11,067	(32,299)	-137.56%	-53.41%	-41.93%	29.34%	29.67%	24.53%	21.95%	18.05%	17.89%	17.89%
1978	80,753	22,383	14,926	7,457	9.23%	-23.83%	-8.73%	-11.05%	18.44%	20.15%	17.96%	16.88%	14.88%	14.78%
1979	50,967	6,921	21,584	(14,663)	-28.77%	-5.47%	-25.45%	-14.95%	-15.94%	6.41%	9.03%	8.00%	7.69%	6.80%
1980	35,605	22,108	57,784	(35,676)	-100.20%	-58.15%	-25.63%	-39.40%	-30.14%	-29.55%	-9.71%	-5.94%	-6.02%	-5.60%
1981	101,087	72,317	26,159	46,158	45.66%	7.67%	-2.23%	1.22%	-9.94%	-4.68%	-5.90%	6.92%	8.51%	7.88%
1982	67,171	36,173	33,419	2,754	4.10%	29.07%	6.49%	-0.56%	1.80%	-7.32%	-3.07%	-4.17%	6.45%	7.82%
1983	73,148	85,054	30,023	55,031	75.23%	41.18%	43.06%	24.64%	16.34%	14.94%	6.65%	9.91%	8.41%	17.00%
1984	70,630	17,137	21,494	(4,357)	-6.17%	35.24%	25.33%	31.91%	18.38%	12.35%	11.83%	4.85%	7.69%	6.47%
1985	82,520	106,421	16,770	89,651	108.64%	55.69%	62.01%	48.75%	47.96%	35.70%	28.87%	26.05%	19.48%	21.71%
1986	26,360	104,119	17,643	86,476	328.06%	161.76%	95.69%	89.77%	71.77%	65.50%	52.58%	44.41%	39.58%	32.78%
1987	176,931	305,993	25,515	280,478	158.52%	180.51%	159.76%	126.88%	118.08%	102.67%	93.03%	82.17%	73.91%	67.08%
1988	71,981	84,716	27,728	56,988	79.17%	135.58%	154.01%	143.55%	118.86%	112.50%	99.70%	91.54%	81.87%	74.41%
1989	87,195	50,357	17,237	33,120	37.98%	56.61%	110.26%	126.10%	122.86%	105.19%	101.46%	91.49%	85.37%	77.04%
1990	179,821	132,120	49,192	82,928	46.12%	43.46%	51.04%	87.90%	99.58%	100.77%	89.91%	88.52%	81.73%	77.84%
1991	199,509	102,292	40,741	61,551	30.85%	38.09%	38.07%	43.56%	71.99%	81.09%	83.85%	76.75%	76.63%	71.93%
1992	412,064	3,526	69,671	(66,145)	-16.05%	-0.75%	9.90%	12.69%	17.72%	39.82%	46.40%	50.55%	47.49%	48.96%
1993	212,635	18,927	51,695	(32,768)	-15.41%	-15.83%	-4.53%	4.54%	7.21%	11.66%	31.05%	36.78%	40.87%	38.69%
1994	377,917	2,738	44,330	(41,592)	-11.01%	-12.59%	-14.01%	-6.57%	0.29%	2.52%	6.10%	21.80%	26.43%	30.14%
1995	679,958	(31,276)	71,879	(103,155)	-15.17%	-13.68%	-13.97%	-14.48%	-9.68%	-4.81%	-3.07%	-0.41%	11.32%	14.76%
1996	122,055	74,816	67,252	7,564	6.20%	-11.92%	-11.63%	-12.20%	-13.08%	-8.71%	-4.19%	-2.58%	-0.06%	11.07%
1997	410,820	50,651	60,089	(9,438)	-2.30%	-0.35%	-8.66%	-9.22%	-9.95%	-11.08%	-7.62%	-3.89%	-2.53%	-0.40%
1998	718,480	24,132	91,963	(67,831)	-9.44%	-6.84%	-5.57%	-8.95%	-9.29%	-9.80%	-10.68%	-8.04%	-5.10%	-3.99%
1999	1,047,583	12,955	75,413	(62,458)	-5.96%	-7.38%	-6.42%	-5.75%	-7.90%	-8.25%	-8.68%	-9.44%	-7.52%	-5.31%
2000	722,555	17,415	51,491	(34,076)	-4.72%	-5.45%	-6.60%	-5.99%	-5.50%	-7.28%	-7.62%	-8.01%	-8.71%	-7.10%
2001	574,391	(6)	30,747	(30,753)	-5.35%	-5.00%	-5.43%	-6.37%	-5.89%	-5.48%	-7.02%	-7.34%	-7.70%	-8.35%
2002	799,169	(426)	52,732	(53,158)	-6.65%	-6.11%	-5.63%	-5.74%	-6.43%	-6.03%	-5.69%	-6.96%	-7.24%	-7.55%
2003	691,219	-	123	(123)	-0.02%	-3.57%	-4.07%	-4.24%	-4.71%	-5.46%	-5.19%	-4.92%	-6.13%	-6.43%
2004	400,630	-	13,816	(13,816)	-3.45%	-1.28%	-3.55%	-3.97%	-4.14%	-4.59%	-5.29%	-5.06%	-4.81%	-5.96%
2005	874,539	83,379	74,903	8,476	0.97%	-0.42%	-0.28%	-2.12%	-2.68%	-3.04%	-3.64%	-4.35%	-4.22%	-4.02%
2006	658,489	-	98,788	(98,788)	-15.00%	-5.89%	-5.39%	-3.97%	-4.60%	-4.71%	-4.71%	-4.94%	-5.43%	-5.25%
2007	1,668,721	-	152,404	(152,404)	-9.13%	-10.79%	-7.58%	-7.12%	-5.98%	-6.08%	-6.01%	-5.86%	-5.88%	-6.19%
2008	1,772,781	-	306,435	(306,435)	-17.29%	-13.33%	-13.60%	-11.04%	-10.47%	-9.28%	-8.98%	-8.70%	-8.34%	-8.07%
2009	1,073,526	-	243,617	(243,617)	-22.69%	-19.33%	-15.56%	-15.49%	-13.11%	-12.51%	-11.30%	-10.83%	-10.46%	-10.01%
2010	1,606,639	-	239,095	(239,095)	-14.88%	-18.01%	-17.72%	-15.38%	-15.34%	-13.48%	-12.98%	-11.96%	-11.51%	-11.16%
2011	624,914	-	338,991	(338,991)	-54.25%	-25.91%	-24.86%	-22.22%	-18.98%	-18.63%	-16.56%	-15.95%	-14.78%	-14.14%
2012	575,885	28,892	128,955	(100,063)	-17.38%	-36.56%	-24.16%	-23.75%	-21.72%	-18.85%	-18.54%	-16.61%	-16.04%	-14.93%
2013	498,094	12,923	207,708	(194,785)	-39.11%	-27.45%	-37.31%	-26.41%	-25.50%	-23.13%	-20.14%	-19.74%	-17.81%	-17.22%
2014	709,130	526	169,519	(168,993)	-23.83%	-30.13%	-26.01%	-33.34%	-25.95%	-25.27%	-23.20%	-20.45%	-20.06%	-18.23%
2015	939,214	7,063	182,689	(175,626)	-18.70%	-20.91%	-25.13%	-23.49%	-29.23%	-24.58%	-24.24%	-22.66%	-20.28%	-19.93%
2016	596,095		3,793,004	(3,793,004)	-636.31%	-258.49%	-184.35%	-157.97%	-133.57%	-121.00%	-90.28%	-79.33%	-66.23%	-56.76%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Measure & Regulating Station Equipment - General
Account 378
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	70	58	12	NA									
1951	-	211	43	168	NA	NA								
1952	-	1,464	2,474	(1,010)	NA	NA	NA							
1953	-	(235)	1,000	(1,235)	NA	NA	NA	NA						
1954	-	242	135	107	NA	NA	NA	NA	NA					
1955	-	690	97	593	NA	NA	NA	NA	NA	NA				
1956	-	3,965	601	3,364	NA	NA	NA	NA	NA	NA	NA			
1957	-	5,073	2,388	2,685	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	1,573	510	1,063	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	2,483	2,045	438	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	5,753	2,369	3,384	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	5,412	1,827	3,585	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	828	2,311	(1,483)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	4,398	2,126	2,272	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	746	528	218	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	831	2,442	(1,611)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	2,805	1,257	1,548	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	-	962	494	468	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1968	-	2,020	5,436	(3,416)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1969	-	3,286	1,476	1,810	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1970	-	16,395	9,504	6,891	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1971	-	7,019	2,502	4,517	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1972	-	4,666	3,624	1,042	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1973	-	3,442	2,002	1,440	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1974	-	2,989	1,725	1,264	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1975	-	(188)	8,082	(8,270)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1976	-	4,636	16,426	(11,790)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1977	-	2,572	89	2,483	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1978	-	3,146	19,089	(15,943)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1979	-	9,160	7,835	1,325	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1980	-	1,196	10,892	(9,696)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1981	-	592	11,794	(11,202)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1982	-	12,783	9,841	2,942	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1983	-	44,873	11,598	33,275	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1984	-	14,488	8,070	6,418	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1985	-	107	327	(220)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1986	-	(18,487)	-	(18,487)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1987	-	(9,061)	-	(9,061)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1988	-	39	14,752	(14,713)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1989	-	730	5,490	(4,760)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1990	-	(115)	11,898	(12,013)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1991	-	(33)	10,486	(10,519)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1992	-	-	18,741	(18,741)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1993	-	(1,260)	16,928	(18,188)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1994	-	(626)	23,307	(23,933)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1995	-	-	24,383	(24,383)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1996	-	-	32,297	(32,297)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1997	-	(33)	60,207	(60,240)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1998	-	(18)	64,663	(64,681)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	-	(333)	43,594	(43,927)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2000	-	152	45,895	(45,743)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2001	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2002	8,815	-	407	(407)	-4.62%	-4.62%	-523.54%	-1021.86%	-1755.61%	-2438.98%	-2805.37%	-3081.97%	-3353.47%	-3559.80%
2003	9,566	-	460	(460)	-4.80%	-4.72%	-4.72%	-253.58%	-492.57%	-844.47%	-1172.20%	-1347.92%	-1480.57%	-1610.78%
2004	474	-	48,720	(48,720)	-10267.97%	-489.84%	-262.99%	-262.99%	-505.60%	-738.57%	-1081.61%	-1401.10%	-1572.39%	-1701.71%
2005	20,557	-	7,962	(7,962)	-38.73%	-269.51%	-186.76%	-146.02%	-146.02%	-262.08%	-373.54%	-537.65%	-690.50%	-772.45%
2006	49,209	-	23,213	(23,213)	-47.17%	-44.69%	-113.75%	-100.69%	-91.13%	-91.13%	-142.75%	-192.32%	-265.30%	-333.28%
2007	85,150	-	43,100	(43,100)	-50.62%	-49.36%	-47.95%	-79.15%	-74.84%	-71.28%	-71.28%	-97.60%	-122.88%	-160.10%
2008	1,306	-	-	0	0.00%	-49.85%	-48.88%	-47.55%	-78.49%	-74.25%	-70.75%	-70.75%	-96.88%	-121.97%
2009	16,993	-	12,543	(12,543)	-73.81%	-68.55%	-53.79%	-51.66%	-50.12%	-78.04%	-74.21%	-71.02%	-71.02%	-94.84%
2010	2,203	-	-	0	0.00%	-65.34%	-61.18%	-52.67%	-50.92%	-49.49%	-77.06%	-73.33%	-70.21%	-70.21%
2011	2,119	-	15,709	(15,709)	-741.39%	-363.47%	-132.55%	-124.89%	-66.21%	-60.24%	-57.75%	-84.97%	-80.88%	-77.46%
2012	93,682	128,388	138,538	(10,150)	-10.83%	-26.99%	-26.39%	-33.39%	-33.02%	-40.46%	-41.78%	-41.55%	-59.41%	-57.55%
2013	27,399		4,028	(4,028)	-14.70%	-11.71%	-24.26%	-23.83%	-29.80%	-29.53%	-37.37%	-39.11%	-39.08%	-55.31%
2014	1,228	113,620	116,144	(2,525)	-205.66%	-22.89%	-13.66%	-26.05%	-25.60%	-31.30%	-31.02%	-38.27%	-39.84%	-39.76%
2015	293,236		74,629	(74,629)	-25.45%	-26.20%	-25.22%	-21.98%	-25.63%	-25.49%	-27.37%	-27.29%	-31.09%	-32.47%
2016	60,115		3,919	(3,919)	-6.52%	-22.23%	-22.86%	-22.28%	-20.03%	-23.22%	-23.12%	-24.85%	-24.79%	-28.56%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Measure & Regulating Station Equipment - City Gate
Account 379
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	793	-	-	0	0.00%									
1951	341	-	-	0	0.00%	0.00%								
1952	21,476	-	-	0	0.00%	0.00%	0.00%							
1953	5,715	-	-	0	0.00%	0.00%	0.00%	0.00%						
1954	3,166	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%					
1955	860	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
1956	9,293	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
1957	40,475	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
1958	751	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
1959	19,837	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1960	46,004	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1961	15,591	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1962	22,040	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1963	61,100	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1964	8,807	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1965	16,512	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1966	15,499	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1967	9,737	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1968	32,546	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1969	17,565	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1970	18,101	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1971	10,939	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1972	19,911	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1973	23,660	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1974	6,786	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1975	21,180	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1976	34,435	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1977	3,530	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1978	98,545	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1979	84,055	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1980	28,236	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1981	107,307	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1982	111,108	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1983	58,306	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1984	110,686	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1985	5,649	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1986	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1987	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1988	160,011	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1989	76,757	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1990	53,406	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1991	86,250	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1992	171,373	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1993	245,739	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1994	287,322	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1995	131,413	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1996	266,836	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1997	136,515	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1998	194,779	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1999	260,094	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2000	52,736	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2001	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2002	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2003	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2004	-	-	-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2005	12,025	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2006	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2007	3,000	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2008	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2009	-	-	310	(310)	NA	NA	-10.34%	-10.34%	-2.06%	-2.06%	-2.06%	-2.06%	-2.06%	-0.46%
2010	-	-	-	0	NA	NA	NA	-10.34%	-10.34%	-2.06%	-2.06%	-2.06%	-2.06%	-2.06%
2011	-	-	-	0	NA	NA	NA	NA	-10.34%	-10.34%	-2.06%	-2.06%	-2.06%	-2.06%
2012	-	-	-	0	NA	NA	NA	NA	NA	-10.34%	-10.34%	-2.06%	-2.06%	-2.06%
2013	-		-	0	NA	NA	NA	NA	NA	NA	-10.34%	-10.34%	-2.06%	-2.06%
2014	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-10.34%	-10.34%	-2.06%
2015	6,424		73,058	(73,058)	-1137.27%	-1137.27%	-1137.27%	-1137.27%	-1137.27%	-1137.27%	-1142.09%	-1142.09%	-778.55%	-778.55%
2016	94,420		920	(920)	-0.97%	-73.36%	-73.36%	-73.36%	-73.36%	-73.36%	-73.36%	-73.67%	-73.67%	-71.54%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Services - Metallic
Account 380
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	6,197	3	5,236	(5,233)	-84.44%									
1951	5,205	127	4,856	(4,729)	-90.85%	-87.37%								
1952	17,277	36	9,454	(9,418)	-54.51%	-62.93%	-67.58%							
1953	15,269	38	8,072	(8,034)	-52.62%	-53.62%	-58.76%	-62.38%						
1954	21,309	140	13,024	(12,884)	-60.46%	-57.19%	-56.33%	-59.37%	-61.75%					
1955	16,255	41	9,654	(9,613)	-59.14%	-59.89%	-57.79%	-56.98%	-59.32%	-61.23%				
1956	45,687	363	10,010	(9,647)	-21.12%	-31.09%	-38.61%	-40.78%	-42.83%	-44.90%	-46.82%			
1957	31,602	82	12,500	(12,418)	-39.29%	-28.55%	-33.86%	-38.80%	-40.42%	-42.07%	-43.74%	-45.32%		
1958	29,525	(88)	13,244	(13,332)	-45.15%	-42.13%	-33.14%	-36.57%	-40.10%	-41.30%	-42.59%	-43.97%	-45.30%	
1959	35,626	2,497	22,108	(19,611)	-55.05%	-50.56%	-46.88%	-38.62%	-40.72%	-43.06%	-43.80%	-44.68%	-45.78%	-46.85%
1960	49,007	3,004	43,930	(40,926)	-83.51%	-71.53%	-64.71%	-59.20%	-50.11%	-50.82%	-51.71%	-51.77%	-51.95%	-52.71%
1961	24,930	518	37,704	(37,186)	-149.16%	-105.65%	-89.19%	-79.85%	-72.34%	-61.52%	-61.36%	-61.28%	-60.79%	-60.41%
1962	40,373	3,098	49,880	(46,782)	-115.87%	-128.58%	-109.26%	-96.38%	-87.95%	-80.67%	-70.07%	-69.42%	-68.77%	-67.97%
1963	37,209	860	48,458	(47,598)	-127.92%	-121.65%	-128.34%	-113.84%	-102.65%	-94.81%	-87.75%	-77.39%	-76.44%	-75.41%
1964	55,921	53	95,052	(94,999)	-169.88%	-153.12%	-141.85%	-143.00%	-128.95%	-118.12%	-110.21%	-102.85%	-92.17%	-90.71%
1965	57,529	80	68,093	(68,013)	-118.22%	-143.69%	-139.79%	-134.74%	-136.40%	-126.62%	-118.14%	-111.61%	-105.29%	-95.85%
1966	49,230	192	63,443	(63,251)	-128.48%	-122.95%	-139.08%	-137.01%	-133.46%	-134.93%	-126.91%	-119.59%	-113.80%	-108.07%
1967	53,495	6	68,249	(68,243)	-127.57%	-128.01%	-124.49%	-136.23%	-135.01%	-132.38%	-133.70%	-127.01%	-120.65%	-115.50%
1968	60,123	266	72,934	(72,668)	-120.87%	-124.02%	-125.37%	-123.50%	-132.89%	-132.30%	-130.43%	-131.66%	-126.14%	-120.68%
1969	56,841	4	88,300	(88,296)	-155.34%	-137.62%	-134.46%	-133.12%	-130.03%	-136.72%	-135.84%	-133.87%	-134.75%	-129.57%
1970	48,719	7,168	79,589	(72,421)	-148.65%	-152.25%	-140.86%	-137.62%	-135.94%	-132.81%	-138.24%	-137.33%	-135.44%	-136.15%
1971	65,848	9,095	118,641	(109,546)	-166.36%	-158.83%	-157.67%	-148.11%	-144.26%	-141.93%	-138.45%	-142.38%	-141.27%	-139.32%
1972	103,125	10,290	107,579	(97,289)	-94.34%	-122.41%	-128.28%	-133.88%	-131.54%	-131.00%	-130.71%	-129.26%	-133.39%	-133.04%
1973	71,461	13,397	166,605	(153,208)	-214.39%	-143.48%	-149.75%	-149.56%	-150.51%	-146.12%	-143.96%	-142.47%	-140.00%	-142.69%
1974	108,303	94,646	174,606	(79,960)	-73.83%	-129.71%	-116.82%	-126.17%	-128.93%	-132.23%	-130.90%	-130.59%	-130.42%	-129.38%
1975	93,629	5,341	171,786	(166,445)	-177.77%	-122.02%	-146.17%	-131.97%	-137.09%	-138.24%	-140.01%	-138.12%	-137.27%	-136.66%
1976	135,413	8,655	210,172	(201,517)	-148.82%	-160.65%	-132.78%	-147.05%	-136.43%	-139.84%	-140.52%	-141.76%	-140.07%	-139.23%
1977	117,142	821	126,658	(125,837)	-107.42%	-129.62%	-142.64%	-126.24%	-138.22%	-131.03%	-134.38%	-135.31%	-136.73%	-135.62%
1978	150,341	9,092	219,945	(210,853)	-140.25%	-125.87%	-133.58%	-141.92%	-129.72%	-138.67%	-132.81%	-135.42%	-136.14%	-137.29%
1979	152,141	8,712	226,018	(217,306)	-142.83%	-141.55%	-132.02%	-136.12%	-142.13%	-132.36%	-139.44%	-134.44%	-136.55%	-137.11%
1980	277,354	9,085	311,143	(302,058)	-108.91%	-120.92%	-125.94%	-122.82%	-127.05%	-132.18%	-126.07%	-131.78%	-128.58%	-130.54%
1981	384,302	9,613	411,144	(401,531)	-104.48%	-106.34%	-113.16%	-117.38%	-116.31%	-119.92%	-124.06%	-120.22%	-124.74%	-122.77%
1982	314,996	(78)	308,084	(308,162)	-97.83%	-101.49%	-103.59%	-108.88%	-112.57%	-112.14%	-115.38%	-118.97%	-116.15%	-120.04%
1983	170,800	228	128,131	(127,903)	-74.88%	-89.76%	-96.26%	-99.32%	-104.41%	-108.13%	-108.08%	-111.32%	-114.78%	-112.45%
1984	154,357	1,135	136,495	(135,360)	-87.69%	-80.96%	-89.26%	-94.97%	-97.94%	-102.64%	-106.16%	-106.25%	-109.35%	-112.64%
1985	321,721	833	120,889	(120,056)	-37.32%	-53.65%	-59.26%	-71.89%	-81.19%	-85.93%	-90.80%	-94.66%	-95.39%	-98.72%
1986	213,032	5,331	164,712	(159,381)	-74.82%	-52.26%	-60.19%	-63.11%	-72.42%	-80.32%	-84.64%	-89.09%	-92.69%	-93.45%
1987	203,059	12	164,404	(164,392)	-80.96%	-77.81%	-60.15%	-64.92%	-66.52%	-73.68%	-80.40%	-84.27%	-88.34%	-91.67%
1988	263,412	3,142	136,838	(133,696)	-50.76%	-63.90%	-67.32%	-57.68%	-61.69%	-63.39%	-70.00%	-76.54%	-80.44%	-84.31%
1989	457,349	2,146	233,570	(231,424)	-50.60%	-50.66%	-57.32%	-60.60%	-55.46%	-58.55%	-60.11%	-65.77%	-71.76%	-75.50%
1990	788,528	736	261,198	(260,462)	-33.03%	-39.48%	-41.45%	-46.13%	-49.31%	-47.59%	-50.17%	-51.81%	-56.83%	-62.43%
1991	769,364	3,176	356,511	(353,335)	-45.93%	-39.40%	-41.94%	-42.96%	-46.07%	-48.34%	-47.17%	-49.14%	-50.45%	-54.54%
1992	981,414	133	358,621	(358,488)	-36.53%	-40.66%	-38.29%	-40.17%	-41.02%	-43.37%	-45.19%	-44.55%	-46.16%	-47.29%
1993	384,230	5,641	221,147	(215,506)	-56.09%	-42.03%	-43.43%	-40.63%	-41.98%	-42.61%	-44.64%	-46.22%	-45.57%	-47.00%
1994	764,226	3,172	219,899	(216,727)	-28.36%	-37.64%	-37.13%	-39.46%	-38.09%	-39.47%	-40.14%	-41.94%	-43.39%	-43.01%
1995	993,608	2,207	261,141	(258,934)	-26.06%	-27.06%	-32.27%	-33.61%	-36.04%	-35.53%	-36.87%	-37.55%	-39.12%	-40.43%
1996	282,088	1,968	183,025	(181,057)	-64.18%	-34.49%	-32.19%	-35.98%	-36.14%	-37.94%	-37.16%	-38.30%	-38.87%	-40.32%
1997	78,224	838	155,036	(154,198)	-197.12%	-93.05%	-43.89%	-38.28%	-41.02%	-39.75%	-40.87%	-39.64%	-40.55%	-41.02%
1998	1,097,883	2,977	174,357	(171,380)	-15.61%	-27.68%	-34.74%	-31.22%	-30.54%	-33.27%	-33.97%	-35.69%	-35.35%	-36.40%
1999	862,107	5,293	106,935	(101,642)	-11.79%	-13.93%	-20.96%	-26.22%	-26.17%	-26.58%	-29.12%	-30.46%	-32.37%	-32.45%
2000	758,051	10,864	127,418	(116,554)	-15.38%	-13.47%	-14.33%	-19.45%	-23.55%	-24.16%	-24.82%	-27.12%	-28.61%	-30.52%
2001	419,823	(669)	69,516	(70,185)	-16.72%	-15.85%	-14.14%	-14.65%	-19.09%	-22.73%	-23.46%	-24.18%	-26.35%	-27.86%
2002	119,335	(433)	73,631	(74,064)	-62.06%	-26.75%	-20.10%	-16.79%	-16.39%	-20.63%	-24.02%	-24.46%	-25.02%	-27.09%
2003	194,028	-	65,576	(65,576)	-33.80%	-44.56%	-28.62%	-21.89%	-18.19%	-17.37%	-21.35%	-24.52%	-24.84%	-25.32%
2004	-	-	103	(103)	NA	-33.85%	-44.59%	-28.63%	-21.89%	-18.19%	-17.37%	-21.35%	-24.52%	-24.84%
2005	537	-	6,722	(6,722)	-1251.68%	-1270.82%	-37.21%	-46.66%	-29.53%	-22.34%	-18.47%	-17.56%	-21.54%	-24.70%
2006	7,297	-	6,902	(6,902)	-94.60%	-173.92%	-175.23%	-39.29%	-47.75%	-30.17%	-22.69%	-18.71%	-17.73%	-21.69%
2007	747,051	301	320,072	(319,771)	-42.80%	-43.31%	-44.17%	-44.18%	-42.06%	-44.29%	-36.51%	-29.38%	-24.50%	-22.18%
2008	325,115	-	260,296	(260,296)	-80.06%	-54.10%	-54.38%	-54.97%	-54.98%	-51.75%	-52.64%	-44.32%	-35.79%	-29.76%
2009	152,343	-	205,883	(205,883)	-135.14%	-97.64%	-64.18%	-64.37%	-64.88%	-64.89%	-60.66%	-60.77%	-51.36%	-41.34%
2010	542,203	-	277,790	(277,790)	-51.23%	-69.64%	-72.96%	-60.21%	-60.35%	-60.71%	-60.72%	-58.06%	-58.29%	-51.33%
2011	502,649	-	21,671	(21,671)	-4.31%	-28.66%	-42.21%	-50.29%	-47.83%	-47.98%	-48.26%	-48.27%	-47.13%	-47.82%
2012	456,043	-	151,664	(151,664)	-33.26%	-18.08%	-30.06%	-39.74%	-46.37%	-45.39%	-45.52%	-45.76%	-45.76%	-44.97%
2013	268,225		253,371	(253,371)	-94.46%	-55.92%	-34.78%	-39.82%	-47.38%	-52.11%	-49.79%	-49.90%	-50.11%	-50.11%
2014	106,689	-	65,872	(65,872)	-61.74%	-85.15%	-56.67%	-36.94%	-41.07%	-48.14%	-52.55%	-50.20%	-50.30%	-50.51%
2015	370,867		121,849	(121,849)	-32.86%	-39.31%	-59.14%	-49.32%	-36.05%	-39.71%	-45.77%	-49.87%	-48.35%	-48.44%
2016	362,402		38,040	(38,040)	-10.50%	-21.80%	-26.88%	-43.24%	-40.33%	-31.57%	-35.65%	-41.14%	-45.24%	-44.77%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Services - Plastic
Account 380
1970-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1970	8,822	106	2,488	(2,382)	-27.00%									
1971	8,573	(115)	2,563	(2,678)	-31.24%	-29.09%								
1972	17,781	1,590	5,244	(3,654)	-20.55%	-24.03%	-24.77%							
1973	40,040	454	14,296	(13,842)	-34.57%	-30.26%	-30.39%	-29.99%						
1974	51,456	17,467	21,140	(3,673)	-7.14%	-19.14%	-19.37%	-20.24%	-20.71%					
1975	25,235	1,762	17,817	(16,055)	-63.62%	-25.72%	-28.76%	-27.67%	-27.89%	-27.84%				
1976	42,762	3,480	17,478	(13,998)	-32.73%	-44.20%	-28.23%	-29.82%	-28.89%	-29.00%	-28.91%			
1977	132,564	1,733	22,929	(21,196)	-15.99%	-20.07%	-25.55%	-21.79%	-23.54%	-23.37%	-23.58%	-23.68%		
1978	55,089	13,057	33,166	(20,109)	-36.50%	-22.01%	-24.00%	-27.91%	-24.43%	-25.60%	-25.35%	-25.49%	-25.52%	
1979	197,247	9,776	45,751	(35,975)	-18.24%	-22.23%	-20.08%	-21.34%	-23.70%	-22.01%	-22.93%	-22.86%	-22.98%	-23.05%
1980	132,930	13,543	69,596	(56,053)	-42.17%	-27.87%	-29.11%	-25.75%	-26.28%	-27.89%	-26.21%	-26.71%	-26.55%	-26.61%
1981	210,468	39,260	93,176	(53,916)	-25.62%	-32.02%	-26.99%	-27.87%	-25.71%	-26.10%	-27.29%	-26.07%	-26.45%	-26.33%
1982	254,407	8,266	63,104	(54,838)	-21.56%	-23.39%	-27.57%	-25.25%	-25.98%	-24.63%	-24.97%	-25.90%	-25.02%	-25.36%
1983	143,208	1,693	51,619	(49,926)	-34.86%	-26.35%	-26.10%	-28.98%	-26.72%	-27.26%	-25.94%	-26.18%	-26.98%	-26.16%
1984	133,589	2,604	60,332	(57,728)	-43.21%	-38.89%	-30.59%	-29.18%	-31.15%	-28.78%	-29.15%	-27.77%	-27.93%	-28.61%
1985	142,963	11,550	39,776	(28,226)	-19.74%	-31.08%	-32.37%	-28.29%	-27.65%	-29.55%	-27.71%	-28.09%	-26.95%	-27.12%
1986	95,770	22,810	62,002	(39,192)	-40.92%	-28.24%	-33.61%	-33.96%	-29.86%	-28.95%	-30.53%	-28.68%	-28.99%	-27.84%
1987	166,822	64,299	75,014	(10,715)	-6.42%	-19.01%	-19.27%	-25.20%	-27.23%	-25.69%	-25.67%	-27.39%	-26.17%	-26.54%
1988	137,917	46,472	72,044	(25,572)	-18.54%	-11.91%	-18.85%	-19.08%	-23.84%	-25.77%	-24.77%	-24.91%	-26.53%	-25.51%
1989	140,084	12,402	77,618	(65,216)	-46.55%	-32.66%	-22.82%	-26.03%	-24.71%	-27.74%	-28.80%	-27.28%	-27.04%	-28.33%
1990	349,291	4,096	110,758	(106,662)	-30.54%	-35.12%	-31.48%	-26.21%	-27.80%	-26.68%	-28.58%	-29.26%	-28.01%	-27.73%
1991	254,831	20,544	182,930	(162,386)	-63.72%	-44.54%	-44.92%	-40.79%	-35.33%	-35.79%	-34.01%	-34.88%	-34.88%	-33.01%
1992	451,363	6,116	208,587	(202,471)	-44.86%	-51.67%	-44.67%	-44.89%	-42.17%	-38.19%	-38.36%	-36.83%	-37.28%	-37.11%
1993	610,266	31,910	276,052	(244,142)	-40.01%	-42.07%	-46.26%	-42.96%	-43.24%	-41.49%	-38.72%	-38.81%	-37.65%	-37.95%
1994	705,761	21,928	314,158	(292,230)	-41.41%	-40.76%	-41.80%	-44.57%	-42.50%	-42.73%	-41.47%	-39.39%	-39.44%	-38.52%
1995	739,770	51,941	377,392	(325,451)	-43.99%	-42.73%	-41.92%	-42.45%	-44.41%	-42.86%	-43.01%	-42.02%	-40.35%	-40.36%
1996	255,077	78,334	376,198	(297,864)	-116.77%	-62.65%	-53.84%	-50.18%	-49.31%	-50.53%	-48.46%	-48.38%	-47.25%	-45.46%
1997	123,681	93,960	304,165	(210,205)	-169.96%	-134.14%	-74.52%	-61.71%	-56.27%	-54.48%	-55.23%	-52.76%	-52.52%	-51.28%
1998	1,213,825	72,118	327,413	(255,295)	-21.03%	-34.80%	-47.93%	-46.68%	-45.46%	-44.55%	-44.58%	-45.70%	-44.57%	-44.63%
1999	1,955,088	110,770	285,652	(174,882)	-8.94%	-13.57%	-19.45%	-26.45%	-29.47%	-31.16%	-32.12%	-33.07%	-34.31%	-34.11%
2000	870,978	96,624	271,789	(175,165)	-20.11%	-12.39%	-14.98%	-19.59%	-25.20%	-27.89%	-29.52%	-30.51%	-31.44%	-32.59%
2001	1,038,157	443	165,476	(165,033)	-15.90%	-17.82%	-13.33%	-15.17%	-18.85%	-23.43%	-25.88%	-27.47%	-28.49%	-29.42%
2002	210,674	(1,780)	158,565	(160,345)	-76.11%	-26.05%	-23.61%	-16.58%	-17.60%	-21.08%	-25.39%	-27.54%	-28.91%	-29.79%
2003	778,902	-	127,486	(127,486)	-16.37%	-29.09%	-22.33%	-21.67%	-16.54%	-17.44%	-20.49%	-24.30%	-26.32%	-27.67%
2004	-	-	2,855	(2,855)	NA	-16.73%	-29.37%	-22.47%	-21.76%	-16.60%	-17.49%	-20.53%	-24.34%	-26.36%
2005	88,767	-	18,592	(18,592)	-20.95%	-24.16%	-17.16%	-28.68%	-22.41%	-21.74%	-16.68%	-17.54%	-20.54%	-24.30%
2006	-	-	1,791	(1,791)	NA	-22.96%	-26.18%	-17.37%	-28.85%	-22.49%	-21.80%	-16.71%	-17.57%	-20.57%
2007	1,663,428	126,255	776,287	(650,032)	-39.08%	-39.19%	-38.26%	-38.42%	-31.64%	-35.05%	-29.79%	-27.98%	-22.35%	-22.14%
2008	757,228	-	371,772	(371,772)	-49.10%	-42.21%	-42.29%	-41.53%	-41.64%	-35.66%	-38.09%	-33.01%	-30.94%	-25.10%
2009	1,756,656	-	809,071	(809,071)	-46.06%	-46.97%	-43.83%	-43.87%	-43.39%	-43.46%	-39.28%	-40.76%	-36.65%	-34.64%
2010	7,637,094	2,209	812,372	(810,163)	-10.61%	-17.24%	-19.61%	-22.35%	-22.37%	-22.36%	-22.38%	-22.01%	-22.90%	-22.38%
2011	1,426,795	-	1,368,203	(1,368,203)	-95.89%	-24.03%	-27.61%	-29.01%	-30.28%	-30.29%	-30.23%	-30.25%	-29.48%	-30.17%
2012	7,931,702	-	521,755	(521,755)	-6.58%	-20.20%	-15.89%	-18.71%	-19.89%	-21.40%	-21.41%	-21.41%	-21.42%	-21.24%
2013	658,086		527,795	(527,795)	-80.20%	-12.22%	-24.14%	-18.28%	-20.80%	-21.86%	-23.17%	-23.18%	-23.17%	-23.18%
2014	283,813	-	695,038	(695,038)	-244.89%	-129.83%	-19.66%	-30.22%	-21.87%	-24.03%	-24.96%	-26.02%	-26.03%	-26.01%
2015	2,072,789		641,933	(641,933)	-30.97%	-56.73%	-61.86%	-21.80%	-30.35%	-22.81%	-24.69%	-25.51%	-26.44%	-26.45%
2016	13,090,836		405,413	(405,413)	-3.10%	-6.91%	-11.28%	-14.10%	-11.62%	-16.34%	-15.02%	-16.58%	-17.27%	-18.24%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Meters
Account 381
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	26,646	2,144	940	1,204	4.52%									
1951	37,990	4,059	2,821	1,238	3.26%	3.78%								
1952	63,040	7,423	2,639	4,784	7.59%	5.96%	5.66%							
1953	60,652	7,433	4,097	3,336	5.50%	6.56%	5.79%	5.61%						
1954	85,796	10,084	4,330	5,754	6.71%	6.21%	6.62%	6.11%	5.95%					
1955	74,520	8,700	3,891	4,809	6.45%	6.59%	6.29%	6.58%	6.19%	6.06%				
1956	62,426	3,707	3,637	70	0.11%	3.56%	4.77%	4.93%	5.41%	5.20%	5.16%			
1957	36,346	3,616	3,140	476	1.31%	0.55%	3.09%	4.29%	4.52%	5.02%	4.86%	4.84%		
1958	37,469	3,238	2,461	777	2.07%	1.70%	0.97%	2.91%	4.01%	4.26%	4.76%	4.64%	4.63%	
1959	39,312	3,672	3,020	652	1.66%	1.86%	1.68%	1.13%	2.71%	3.73%	4.00%	4.50%	4.40%	4.41%
1960	42,518	12,226	1,941	10,285	24.19%	13.37%	9.82%	7.83%	5.62%	5.83%	6.03%	5.96%	6.16%	5.96%
1961	51,352	5,335	2,843	2,492	4.85%	13.61%	10.08%	8.32%	7.09%	5.48%	5.69%	5.89%	5.84%	6.04%
1962	81,735	9,611	3,146	6,465	7.91%	6.73%	10.96%	9.26%	8.19%	7.32%	6.04%	6.11%	6.21%	6.14%
1963	100,878	8,395	2,560	5,835	5.78%	6.74%	6.32%	9.07%	8.15%	7.50%	6.93%	5.98%	6.05%	6.14%
1964	66,968	10,296	3,100	7,196	10.75%	7.76%	7.81%	7.31%	9.40%	8.60%	8.02%	7.49%	6.60%	6.58%
1965	54,775	10,575	3,501	7,074	12.91%	11.72%	9.03%	8.73%	8.17%	9.88%	9.14%	8.58%	8.07%	7.20%
1966	60,906	6,822	3,066	3,756	6.17%	9.36%	9.87%	8.42%	8.30%	7.88%	9.39%	8.78%	8.31%	7.86%
1967	47,219	9,175	2,954	6,221	13.17%	9.23%	10.47%	10.55%	9.10%	8.86%	8.42%	9.74%	9.16%	8.70%
1968	38,275	3,315	3,244	71	0.19%	7.36%	6.86%	8.51%	9.07%	8.17%	8.12%	7.79%	9.07%	8.57%
1969	48,642	7,257	3,241	4,016	8.26%	4.70%	7.68%	7.21%	8.46%	8.94%	8.18%	8.14%	7.83%	9.00%
1970	23,708	3,401	22,229	(18,828)	-79.42%	-20.47%	-13.33%	-5.40%	-2.18%	0.84%	2.79%	3.48%	4.17%	4.23%
1971	68,330	16,142	70	16,072	23.52%	-2.99%	0.90%	0.74%	3.34%	3.94%	5.38%	6.26%	6.16%	6.40%
1972	105,572	64,409	939	63,470	60.12%	45.74%	30.72%	26.29%	22.77%	21.41%	19.04%	18.29%	17.31%	15.42%
1973	113,124	9,753	534	9,219	8.15%	33.24%	30.92%	22.51%	20.58%	18.61%	18.04%	16.61%	16.25%	15.66%
1974	88,323	19,378	989	18,389	20.82%	13.70%	29.67%	28.55%	22.13%	20.63%	19.02%	18.50%	17.23%	16.87%
1975	114,262	8,783	747	8,036	7.03%	13.04%	11.29%	23.53%	23.53%	18.77%	17.86%	16.73%	16.47%	15.59%
1976	114,583	10,423	1,062	9,361	8.17%	7.60%	11.28%	10.46%	20.24%	20.61%	16.84%	16.22%	15.36%	15.23%
1977	169,671	666	1,055	(389)	-0.23%	3.16%	4.27%	7.27%	7.44%	15.32%	16.04%	13.21%	12.92%	12.37%
1978	177,839	17,998	181	17,817	10.02%	5.02%	5.80%	6.04%	8.01%	8.03%	14.25%	14.92%	12.63%	12.42%
1979	174,838	41,213	4,965	36,248	20.73%	15.33%	10.28%	9.90%	9.46%	10.66%	10.36%	15.32%	15.82%	13.86%
1980	266,193	60,676		60,676	22.79%	21.98%	18.54%	14.50%	13.70%	12.95%	13.58%	13.07%	16.82%	17.15%
1981	316,320	41,757		41,757	13.20%	17.58%	18.31%	16.73%	14.13%	13.57%	13.01%	13.49%	13.10%	16.13%
1982	345,536	40,902	693	40,209	11.64%	12.38%	15.37%	16.22%	15.36%	13.54%	13.14%	12.73%	13.13%	12.83%
1983	264,175	4,128	14,608	(10,480)	-3.97%	4.88%	7.72%	11.09%	12.32%	12.05%	10.84%	10.67%	10.46%	10.91%
1984	338,570	1,831	3,181	(1,350)	-0.40%	-1.96%	2.99%	5.55%	8.55%	9.79%	9.82%	8.99%	8.94%	8.85%
1985	272,779	49	2,332	(2,283)	-0.84%	-0.59%	-1.61%	2.14%	4.41%	7.13%	8.33%	8.47%	7.83%	7.85%
1986	286,699	1,386	740	646	0.23%	-0.29%	-0.33%	-1.16%	1.77%	3.76%	6.18%	7.30%	7.50%	7.00%
1987	358,589	6,879	220	6,659	1.86%	1.13%	0.55%	0.29%	-0.45%	1.79%	3.44%	5.55%	6.56%	6.78%
1988	383,673		461	(461)	-0.12%	0.84%	0.67%	0.35%	0.20%	-0.38%	1.46%	2.91%	4.78%	5.71%
1989	450,133	37	384	(347)	-0.08%	-0.10%	0.49%	0.44%	0.24%	0.14%	-0.32%	1.21%	2.46%	4.11%
1990	363,083	1,210	6,588	(5,378)	-1.48%	-0.70%	-0.52%	0.03%	0.06%	-0.06%	-0.10%	-0.48%	0.89%	2.04%
1991	440,704	2	1,950	(1,948)	-0.44%	-0.91%	-0.61%	-0.50%	-0.07%	-0.04%	-0.12%	-0.15%	-0.47%	0.72%
1992	588,449	259	1,448	(1,189)	-0.20%	-0.30%	-0.61%	-0.48%	-0.42%	-0.10%	-0.07%	-0.14%	-0.16%	-0.43%
1993	383,383	2,680	15,953	(13,273)	-3.46%	-1.49%	-1.16%	-1.23%	-0.99%	-0.87%	-0.54%	-0.47%	-0.50%	-0.49%
1994	719,429	600	411	189	0.03%	-1.19%	-0.84%	-0.76%	-0.87%	-0.75%	-0.67%	-0.43%	-0.38%	-0.41%
1995	566,826	101	(2,196)	2,297	0.41%	0.19%	-0.65%	-0.53%	-0.52%	-0.63%	-0.56%	-0.52%	-0.32%	-0.28%
1996	1,141,639	94,452		94,452	8.27%	5.66%	3.99%	2.98%	2.43%	2.10%	1.79%	1.61%	1.48%	1.50%
1997	875,696	60,670		60,670	6.93%	7.69%	6.09%	4.77%	3.91%	3.35%	2.99%	2.67%	2.45%	2.28%
1998	1,517,478	127,900		127,900	8.43%	7.88%	8.01%	6.96%	5.92%	5.23%	4.68%	4.32%	4.00%	3.74%
1999	1,844,190	53,435		53,435	2.90%	5.39%	5.71%	6.26%	5.70%	5.09%	4.62%	4.25%	3.99%	3.76%
2000	2,353,706	8,590		8,590	0.36%	1.48%	3.32%	3.80%	4.46%	4.19%	3.85%	3.56%	3.33%	3.17%
2001	104			0	0.00%	0.36%	1.48%	3.32%	3.80%	4.46%	4.19%	3.85%	3.56%	3.33%
2002				0	NA	0.00%	0.36%	1.48%	3.32%	3.80%	4.46%	4.19%	3.85%	3.56%
2003				0	NA	NA	0.00%	0.36%	1.48%	3.32%	3.80%	4.46%	4.19%	3.85%
2004				0	NA	NA	NA	0.00%	0.36%	1.48%	3.32%	3.80%	4.46%	4.19%
2005	1,723,375			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.21%	1.05%	2.55%	3.01%	3.65%
2006	10,653,105			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.06%	0.37%	1.05%	1.32%
2007	1,201,950		260,415	(260,415)	-21.67%	-2.20%	-1.92%	-1.92%	-1.92%	-1.92%	-1.92%	-1.58%	-1.12%	-0.37%
2008	1,602,503			0	0.00%	-9.29%	-1.94%	-1.72%	-1.72%	-1.72%	-1.72%	-1.72%	-1.44%	-1.02%
2009	1,182,564 *			0	0.00%	0.00%	-6.53%	-1.78%	-1.59%	-1.59%	-1.59%	-1.59%	-1.59%	-1.35%
2010	1,622,257 *		352,882	(352,882)	-21.75%	-12.58%	-8.01%	-10.93%	-3.77%	-3.41%	-3.41%	-3.41%	-3.41%	-3.41%
2011	1,963,880 *			0	0.00%	-9.84%	-7.40%	-5.54%	-8.10%	-3.36%	-3.07%	-3.07%	-3.07%	-3.07%
2012				0	NA	0.00%	-9.84%	-7.40%	-5.54%	-8.10%	-3.36%	-3.07%	-3.07%	-3.07%
2013	2,160,792	879	245,637	(244,758)	-11.33%	-11.33%	-5.93%	-10.40%	-8.62%	-7.00%	-8.82%	-4.21%	-3.88%	-3.88%
2014	2,472,223	17,003	98,719	(81,716)	-3.31%	-7.05%	-7.05%	-4.95%	-8.27%	-7.23%	-6.17%	-7.70%	-4.11%	-3.82%
2015	2,916,824	34,053	133,579	(99,526)	-3.41%	-3.36%	-5.64%	-5.64%	-4.48%	-6.99%	-6.32%	-5.59%	-6.87%	-4.03%
2016	2,520,819	12,018		12,018	0.48%	-1.61%	-2.14%	-4.11%	-4.11%	-3.44%	-5.62%	-5.17%	-4.66%	-5.82%

* Pro forma Ret

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution Meters - Telemetering
Account 381
2009-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2009	601,146	-	-	0	0.00%									
2010		-	-	0	NA	0.00%								
2011		-	-	0	NA	NA	0.00%							
2012		-	-	0	NA	NA	NA	0.00%						
2013		-	-	0	NA	NA	NA	NA	0.00%					
2014		-	-	0	NA	NA	NA	NA	NA	0.00%				
2015		-	-	0	NA	NA	NA	NA	NA	NA	0.00%			
2016		-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%		

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
Distribution House Regulators
Account 383
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	1,070	145	53	92	8.60%									
1951	301	98	60	38	12.62%	9.48%								
1952	299	74	75	(1)	-0.33%	6.17%	7.72%							
1953	558	61	95	(34)	-6.09%	-4.08%	0.26%	4.26%						
1954	2,121	182	180	2	0.09%	-1.19%	-1.11%	0.15%	2.23%					
1955	6,116	1,638	169	1,469	24.02%	17.86%	16.34%	15.79%	15.69%	14.96%				
1956	13,364	61	234	(173)	-1.29%	6.65%	6.01%	5.70%	5.62%	5.72%	5.85%			
1957	843	60	201	(141)	-16.73%	-2.21%	5.68%	5.16%	4.88%	4.82%	4.91%	5.07%		
1958	2,713	80	544	(464)	-17.10%	-17.01%	-4.60%	3.00%	2.75%	2.56%	2.53%	2.64%	2.88%	
1959	2,036	516	393	123	6.04%	-7.18%	-8.62%	-3.46%	3.25%	3.00%	2.82%	2.78%	2.89%	3.10%
1960	11,596	2,540	507	2,033	17.53%	15.82%	10.35%	9.02%	4.51%	7.76%	7.34%	7.15%	7.10%	7.14%
1961	9,620	1,085	1,341	(256)	-2.66%	8.38%	8.17%	5.53%	4.83%	2.79%	5.60%	5.36%	5.23%	5.19%
1962	6,013	2,076	1,119	957	15.92%	4.48%	10.04%	9.76%	7.48%	6.86%	4.50%	6.78%	6.52%	6.40%
1963	9,762	4,111	1,100	3,011	30.84%	25.15%	14.62%	15.53%	15.04%	12.95%	12.36%	9.10%	10.57%	10.22%
1964	10,151	2,557	786	1,771	17.45%	24.01%	22.14%	15.43%	15.94%	15.53%	13.83%	13.34%	10.38%	11.54%
1965	2,188	716	643	73	3.34%	14.94%	21.97%	20.67%	14.72%	15.38%	15.01%	13.40%	12.94%	10.15%
1966	1,793	226	1,733	(1,507)	-84.05%	-36.02%	2.38%	14.01%	14.39%	10.24%	11.90%	11.67%	10.28%	9.87%
1967	4,161	866	1,905	(1,039)	-24.97%	-42.76%	-30.37%	-3.84%	8.23%	9.59%	6.89%	9.12%	9.01%	7.83%
1968	13,826	1,310	1,224	86	0.62%	-5.30%	-12.44%	-10.87%	-1.92%	5.72%	7.00%	5.38%	7.42%	7.38%
1969	16,243	4,883	1,243	3,640	22.41%	12.39%	7.85%	3.28%	3.28%	6.25%	10.38%	10.90%	9.13%	10.27%
1970	4,116	513	1,858	(1,345)	-32.68%	11.27%	6.97%	3.50%	-0.41%	-0.22%	3.20%	7.54%	8.27%	6.92%
1971	4,454	943	2,728	(1,785)	-40.08%	-36.52%	2.06%	1.54%	-1.04%	-4.37%	-4.01%	-0.19%	4.36%	5.31%
1972	18,791	2,242	1,452	790	4.20%	-4.28%	-8.55%	2.98%	2.41%	0.56%	-1.83%	-1.66%	0.90%	4.32%
1973	812	635	2,638	(2,003)	-246.67%	-6.19%	-12.46%	-15.42%	-1.58%	-1.06%	-2.65%	-4.93%	-4.65%	-1.72%
1974	27	23	2,383	(2,360)	-8740.74%	-520.02%	-18.20%	-22.25%	-23.77%	-6.89%	-5.11%	-6.43%	-8.60%	-8.21%
1975	11,025	33	4,469	(4,436)	-40.24%	-61.49%	-74.17%	-26.13%	-27.90%	-28.40%	-13.52%	-10.70%	-11.51%	-13.23%
1976	4,020	1	1,563	(1,562)	-38.86%	-39.87%	-55.45%	-65.23%	-27.60%	-29.02%	-29.37%	-15.23%	-12.24%	-12.93%
1977	6,656	3,658	1,943	1,715	25.77%	1.43%	-19.74%	-30.57%	-38.36%	-19.01%	-21.06%	-22.02%	-11.11%	-9.08%
1978	224	106	2,460	(2,354)	-1050.89%	-9.29%	-20.19%	-30.27%	-40.98%	-48.32%	-24.57%	-26.07%	-26.61%	-14.62%
1979	626	284	1,941	(1,657)	-264.70%	-471.88%	-30.59%	-33.47%	-36.78%	-47.19%	-54.11%	-28.13%	-29.27%	-29.55%
1980	920		4,775	(4,775)	-519.02%	-416.04%	-496.38%	-83.92%	-69.36%	-55.68%	-65.66%	-71.71%	-38.61%	-38.75%
1981	10,487	1,138	11,295	(10,157)	-96.85%	-130.90%	-137.86%	-154.55%	-91.09%	-81.93%	-68.40%	-75.29%	-79.29%	-50.01%
1982	-	700	6,367	(5,667)	NA	-150.89%	-180.58%	-184.96%	-200.78%	-121.05%	-106.65%	-85.08%	-91.96%	-95.57%
1983	1	216	3,941	(3,725)	-372500.00%	-939200.00%	-186.39%	-213.22%	-215.90%	-231.16%	-140.74%	-122.88%	-96.05%	-102.92%
1984	(1)	31	5,927	(5,896)	589600.00%	NA	NA	-242.63%	-264.93%	-264.91%	-279.28%	-171.92%	-148.60%	-113.42%
1985	1	125	3,272	(3,147)	-314700.00%	NA	-1276800.00%	-1843500.00%	-272.62%	-292.49%	-291.04%	-304.93%	-188.55%	-162.31%
1986	-	287	8,247	(7,960)	NA	-1110700.00%	NA	-2072800.00%	-2639500.00%	-348.51%	-362.26%	-357.19%	-369.86%	-230.64%
1987	-	725	5,478	(4,753)	NA	NA	-1586000.00%	NA	-2548100.00%	-3114800.00%	-393.83%	-403.93%	-396.68%	-408.64%
1988	1	269	9,801	(9,532)	-953200.00%	-1428500.00%	-2224500.00%	-1269600.00%	-3128800.00%	-1750650.00%	-2034000.00%	-484.67%	-487.44%	-475.85%
1989	-		166	(166)	NA	-969800.00%	-1445100.00%	-2241100.00%	-1277900.00%	-3145400.00%	-1758950.00%	-2042300.00%	-486.25%	-488.89%
1990	1	442	14,537	(14,095)	-1409500.00%	-1426100.00%	-1189650.00%	-1427300.00%	-1825300.00%	-1321766.67%	-2277450.00%	-1642466.67%	-1831366.67%	-620.57%
1991	-	1	6,816	(6,815)	NA	-2091000.00%	-2107600.00%	-1530400.00%	-1768050.00%	-2166050.00%	-1548933.33%	-2618200.00%	-1869633.33%	-2058533.33%
1992	-	193	7,188	(6,995)	NA	NA	-2790500.00%	-2807100.00%	-1880150.00%	-2117800.00%	-2515800.00%	-1782100.00%	-2967950.00%	-2102800.00%
1993	185,044	-	-	0	0.00%	-3.78%	-7.46%	-15.08%	-15.17%	-20.32%	-22.89%	-27.19%	-28.89%	-32.08%
1994	133,048	-	-	0	0.00%	0.00%	-2.20%	-4.34%	-8.77%	-8.82%	-11.82%	-13.32%	-15.82%	-16.81%
1995	124,714	-	-	0	0.00%	0.00%	0.00%	-1.58%	-3.12%	-6.30%	-6.34%	-8.49%	-9.57%	-11.36%
1996	194,036	-	-	0	0.00%	0.00%	0.00%	0.00%	-1.10%	-2.17%	-4.38%	-4.41%	-5.90%	-6.65%
1997	243,744	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	-0.79%	-1.57%	-3.17%	-3.19%	-4.27%
1998	560,791	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.49%	-0.96%	-1.94%	-1.95%
1999	-	(12,615)	-	(12,615)	NA	-2.25%	-1.57%	-1.26%	-1.12%	-1.00%	-0.88%	-1.36%	-1.83%	-2.81%
2000	788,842	-	-	0	0.00%	-1.60%	-0.93%	-0.79%	-0.71%	-0.66%	-0.62%	-0.57%	-0.88%	-1.18%
2001	-	-	-	0	NA	0.00%	-1.60%	-0.93%	-0.79%	-0.71%	-0.66%	-0.62%	-0.57%	-0.88%
2002	-	-	-	0	NA	NA	0.00%	-1.60%	-0.93%	-0.79%	-0.71%	-0.66%	-0.62%	-0.57%
2003	2,330	-	-	0	0.00%	0.00%	0.00%	0.00%	-1.59%	-0.93%	-0.79%	-0.70%	-0.66%	-0.62%
2004	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	-1.59%	-0.93%	-0.79%	-0.70%	-0.66%
2005	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	-1.59%	-0.93%	-0.79%	-0.70%
2006	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	-1.59%	-0.93%	-0.79%
2007	603,813	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.90%	-0.65%
2008	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.90%
2009	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	69	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	12	-	2,849	(2,849)	-23965.10%	-3511.34%	-3511.34%	-3511.34%	-0.47%	-0.47%	-0.47%	-0.47%	-0.47%	-0.47%
2012				0	NA	-23965.10%	-3511.34%	-3511.34%	-3511.34%	-0.47%	-0.47%	-0.47%	-0.47%	-0.47%
2013				0	NA	NA	-23965.10%	-3511.34%	-3511.34%	-3511.34%	-0.47%	-0.47%	-0.47%	-0.47%
2014	-		4,095	(4,095)	NA	NA	NA	-58402.78%	-8557.10%	-8557.10%	-8557.10%	-1.15%	-1.15%	-1.15%
2015	29		594	(594)	-2048.24%	-16157.96%	-16157.96%	-16157.96%	-18427.01%	-6842.60%	-6842.60%	-6842.60%	-1.25%	-1.25%
2016				0	NA	-2048.24%	-16157.96%	-16157.96%	-16157.96%	-18427.01%	-6842.60%	-6842.60%	-6842.60%	-1.25%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
General Structures & Improvements
Account 390
1950-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
1950	-	-	-	0	NA									
1951	-	-	-	0	NA	NA								
1952	-	-	-	0	NA	NA	NA							
1953	-	-	-	0	NA	NA	NA	NA						
1954	-	-	-	0	NA	NA	NA	NA	NA					
1955	-	-	-	0	NA	NA	NA	NA	NA	NA				
1956	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
1957	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
1958	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
1959	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1960	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1961	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1962	-	-	18	(18)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1963	-	-	57	(57)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1964	-	710	64	646	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1965	-	10,414	-	10,414	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1966	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1967	4,173	-	-	0	0.00%	0.00%	249.56%	265.04%	263.67%	263.24%	263.24%	263.24%	263.24%	263.24%
1968	-	-	-	0	NA	0.00%	0.00%	249.56%	265.04%	263.67%	263.24%	263.24%	263.24%	263.24%
1969	-	-	-	0	NA	NA	0.00%	0.00%	249.56%	265.04%	263.67%	263.24%	263.24%	263.24%
1970	206	30	7	23	11.17%	11.17%	11.17%	0.53%	0.53%	238.34%	253.09%	251.79%	251.38%	251.38%
1971	-	-	-	0	NA	11.17%	11.17%	11.17%	0.53%	0.53%	238.34%	253.09%	251.79%	251.38%
1972	-	-	-	0	NA	NA	11.17%	11.17%	11.17%	0.53%	0.53%	238.34%	253.09%	251.79%
1973	-	-	-	0	NA	NA	NA	11.17%	11.17%	11.17%	0.53%	0.53%	238.34%	253.09%
1974	-	-	-	0	NA	NA	NA	NA	11.17%	11.17%	11.17%	0.53%	0.53%	238.34%
1975	-	-	-	0	NA	NA	NA	NA	NA	11.17%	11.17%	11.17%	0.53%	0.53%
1976	-	-	-	0	NA	NA	NA	NA	NA	NA	11.17%	11.17%	11.17%	0.53%
1977	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	11.17%	11.17%	11.17%
1978	6,719	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.33%	0.33%
1979	-	17	86,083	(86,066)	NA	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1242.50%
1980	-	-	-	0	NA	NA	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%
1981	-	-	-	0	NA	NA	NA	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%
1982	-	-	-	0	NA	NA	NA	NA	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%
1983	-	-	-	0	NA	NA	NA	NA	NA	-1280.93%	-1280.93%	-1280.93%	-1280.93%	-1280.93%
1984	-	-	-	0	NA	NA	NA	NA	NA	NA	-1280.93%	-1280.93%	-1280.93%	-1280.93%
1985	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	-1280.93%	-1280.93%	-1280.93%
1986	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	-1280.93%	-1280.93%
1987	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	-1280.93%
1988	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1989	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1990	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1991	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1992	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1993	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1994	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1995	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1996	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1997	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1998	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	5,000	(12,615)	-	(12,615)	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%
2000	-	-	-	0	NA	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%
2001	-	-	-	0	NA	NA	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%
2002	-	-	-	0	NA	NA	NA	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%	-252.30%
2003	2,330	-	-	0	0.00%	0.00%	0.00%	0.00%	-172.11%	-172.11%	-172.11%	-172.11%	-172.11%	-172.11%
2004	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	-172.11%	-172.11%	-172.11%	-172.11%	-172.11%
2005	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	-172.11%	-172.11%	-172.11%	-172.11%
2006	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	-172.11%	-172.11%	-172.11%
2007	0	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-172.11%	-172.11%
2008	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-172.11%
2009	-	-		0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-		0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-			0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	32,183			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014				0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	3,617		1,517	(1,517)	-41.92%	-41.92%	-41.92%	-4.24%	-4.24%	-4.24%	-4.24%	-4.24%	-4.24%	-4.24%
2016	345,469		47,119	(47,119)	-13.64%	-13.93%	-13.93%	-13.93%	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%	-12.76%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
General Office Furniture & Equipment
Account 391
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	-			0	NA	NA	NA	NA	NA					
2005	-			0	NA	NA	NA	NA	NA	NA				
2006	314			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	1,354			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	107,074	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	2,662			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	-		-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	-		-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Gas Plant
Network Equipment
Account 391
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	211,126			0	0.00%	0.00%	0.00%							
2003	891,533			0	0.00%	0.00%	0.00%	0.00%						
2004	1,195,553			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	20,385			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	1,934			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	28,745			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013				0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	14,837			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	22,729		-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	-		-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Gas Plant
General Transportation Equipment - Automobiles
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	-			0	NA	NA	NA	NA	NA					
2005	-			0	NA	NA	NA	NA	NA	NA				
2006	-			0	NA	NA	NA	NA	NA	NA	NA			
2007	-			0	NA	NA	NA	NA	NA	NA	NA	NA		
2008	-			0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	-			0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
General Transportation Equipment - Light Trucks
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	95214.23			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	11236.34			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	(5,720)	5,720	NA	NA	NA	NA	NA	NA	50.91%	5.37%	5.37%	5.37%
2012	-			0	NA	NA	NA	NA	NA	NA	NA	50.91%	5.37%	5.37%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	50.91%	5.37%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	50.91%
2015	-		-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	239,316	18,180	-	18,180	7.60%	7.60%	7.60%	7.60%	7.60%	9.99%	9.99%	9.99%	9.99%	9.99%

Xcel Energy Gas Plant
General Transportation Equipment - Trailers
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	192,824			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
2012	-			0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	-		-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	14,256		-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Gas Plant
General Transportation Equip - Heavy Trucks
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	1,102,569			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
2012	-			0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	-		-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	-	44,866	-	44,866	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
General Stores Equipment
Account 393
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	-			0	NA	NA	NA	NA	NA					
2005	-			0	NA	NA	NA	NA	NA	NA				
2006	-			0	NA	NA	NA	NA	NA	NA	NA			
2007	-			0	NA	NA	NA	NA	NA	NA	NA	NA		
2008	-			0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	-			0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Xcel Energy Gas Plant
General Tools, Shop & Garage Equipment
Account 394
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	59,775			0	0.00%	0.00%	0.00%							
2003	149,102			0	0.00%	0.00%	0.00%	0.00%						
2004	652,196			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	395,221			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	316,359			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	525,912			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	1,270,951			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	413,970	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	775,000	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	302,442	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	677,271	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	204,565	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Gas Plant
General Laboratory Equipment
Account 395
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	-			0	NA	NA	NA	NA	NA					
2005	11,898			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	310			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	33,318			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	7,380			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	2,517	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	-	-	-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	-	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
General Power Operated Equipment
Account 396
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	-			0	NA	NA	NA	NA	NA					
2005	-			0	NA	NA	NA	NA	NA	NA				
2006	-			0	NA	NA	NA	NA	NA	NA	NA			
2007	66,375			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	70,455	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013				0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-			0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	-		-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	671,655	226,474	-	226,474	33.72%	33.72%	33.72%	33.72%	33.72%	30.52%	30.52%	30.52%	30.52%	28.01%

Xcel Energy Gas Plant
General Communication Equipment
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	8,730			0	0.00%	0.00%	0.00%	0.00%						
2004	1,846,637			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	87,979			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	125,517			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	179,437			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	11,640	-	21,350	(21,350)	-183.42%	-183.42%	-11.17%	-11.17%	-6.74%	-6.74%	-5.28%	-0.95%	-0.94%	-0.94%
2012	17,372		38,436	(38,436)	-221.25%	-206.07%	-206.07%	-28.68%	-28.68%	-17.90%	-17.90%	-14.17%	-2.64%	-2.63%
2013	10,249			0	0.00%	-139.15%	-152.28%	-152.28%	-27.34%	-27.34%	-17.37%	-17.37%	-13.83%	-2.62%
2014	171,106			0	0.00%	0.00%	-19.34%	-28.42%	-28.42%	-15.34%	-15.34%	-11.60%	-11.60%	-9.91%
2015	-		-	0	NA	0.00%	0.00%	-19.34%	-28.42%	-28.42%	-15.34%	-15.34%	-11.60%	-11.60%
2016			-	0	NA	NA	0.00%	0.00%	-19.34%	-28.42%	-28.42%	-15.34%	-15.34%	-11.60%

Xcel Energy Gas Plant
General Communication Equipment - AES
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	-			0	NA	NA	NA							
2003	-			0	NA	NA	NA	NA						
2004	3,294			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	26,179			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	45,532			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	5,338			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	2,147	-	71	(71)	-3.30%	-3.30%	-0.95%	-0.95%	-0.13%	-0.09%	-0.09%	-0.09%	-0.09%	-0.09%
2012				0	NA	-3.30%	-3.30%	-0.95%	-0.95%	-0.13%	-0.09%	-0.09%	-0.09%	-0.09%
2013				0	NA	NA	-3.30%	-3.30%	-0.95%	-0.95%	-0.13%	-0.09%	-0.09%	-0.09%
2014	2,365,462			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	1,331,967		-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016			-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Gas Plant
General Miscellaneous Equipment
Account 398
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-			0	NA	NA								
2002	33,743			0	0.00%	0.00%	0.00%							
2003	-			0	NA	0.00%	0.00%	0.00%						
2004	-			0	NA	NA	0.00%	0.00%	0.00%					
2005	10,161			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	500			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-			0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	5,493			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012				0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	20,200			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014	-			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015	32,504		-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016			-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Structures & Improvements
Account 390
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000			11,128	(11,128)	NA									
2001	11,177		2,928	(2,928)	-26.20%	-125.76%								
2002	84,542			0	0.00%	-3.06%	-14.68%							
2003				0	NA	0.00%	-3.06%	-14.68%						
2004				0	NA	NA	0.00%	-3.06%	-14.68%					
2005	115,441		30,562	(30,562)	NA	-26.47%	-26.47%	-15.28%	-15.86%	-21.13%				
2006	333,652		391,986	(391,986)	NA	-94.09%	-94.09%	-94.09%	-79.18%	-78.10%	-80.14%			
2007	2,085,723		1,689,125	(1,689,125)	-80.99%	-86.02%	-83.31%	-83.31%	-83.31%	-80.62%	-80.39%	-80.81%		
2008	1,493,463		1,988,153	(1,988,153)	-133.12%	-102.74%	-104.00%	-101.78%	-101.78%	-101.78%	-99.68%	-99.48%	-99.75%	
2009	34,948			0	0.00%	-130.08%	-101.75%	-103.08%	-100.90%	-100.90%	-100.90%	-98.84%	-98.65%	-98.92%
2010				0	NA	0.00%	-130.08%	-101.75%	-103.08%	-100.90%	-100.90%	-100.90%	-98.84%	-98.65%
2011		(10,312)	1,041,313	(1,051,625)	NA	NA	-3009.11%	-198.88%	-130.84%	-129.72%	-126.78%	-126.78%	-126.78%	-124.20%
2012	3,697,183	2,874	2,498,298	(2,495,424)	NA	-95.94%	-95.94%	-95.04%	-105.92%	-98.81%	-99.63%	-98.54%	-98.54%	-98.54%
2013	10,192,810		724,240	(724,240)	NA	-23.18%	-30.75%	-30.75%	-30.67%	-40.60%	-45.41%	-46.76%	-46.63%	-46.63%
2014	2,569,934	1,006	610,379	(609,373)	NA	-10.45%	-23.26%	-29.65%	-29.65%	-29.59%	-38.18%	-42.63%	-43.86%	-43.76%
2015	1,033,009	(1,667)		(1,667)	NA	-16.96%	-9.68%	-21.90%	-27.91%	-27.91%	-27.85%	-36.12%	-40.55%	-41.75%
2016	828,431	932	463,032	(462,100)	NA	-24.91%	-24.22%	-12.29%	-23.43%	-29.17%	-29.17%	-29.11%	-36.94%	-41.13%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Office Furniture & Equipment
Account 391
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002	11,807			0	0.00%	0.00%	0.00%							
2003	784,169			0	0.00%	0.00%	0.00%	0.00%						
2004	685,962	7,700		7,700	1.12%	0.52%	0.52%	0.52%	0.52%					
2005		12,781		12,781	NA	2.99%	1.39%	1.38%	1.38%	1.38%				
2006		2,150	1,797	353	NA	NA	3.04%	1.42%	1.41%	1.41%	1.41%			
2007	1,086,869	180	10,001	(9,821)	-0.90%	-0.87%	0.30%	0.62%	0.43%	0.43%	0.43%	0.43%		
2008	989,344	(351,919)		(351,919)	-35.57%	-17.42%	-17.41%	-16.79%	-12.34%	-9.61%	-9.58%	-9.58%	-9.58%	
2009	59,885		8,869	(8,869)	-14.81%	-34.39%	-17.35%	-17.33%	-16.73%	-12.39%	-9.70%	-9.67%	-9.67%	-9.67%
2010	-			0	NA	-14.81%	-34.39%	-17.35%	-17.33%	-16.73%	-12.39%	-9.70%	-9.67%	-9.67%
2011	859,438		48,000	(48,000)	-5.59%	-5.59%	-6.19%	-21.42%	-13.97%	-13.96%	-13.54%	-10.80%	-8.91%	-8.88%
2012	1,179,782			0	NA	-2.35%	-2.35%	-2.71%	-13.24%	-10.03%	-10.02%	-9.71%	-8.18%	-7.05%
2013	4,781,782		17,008	(17,008)	NA	-0.29%	-0.95%	-0.95%	-1.07%	-5.41%	-4.86%	-4.86%	-4.72%	-4.30%
2014	5,902,551	3,247	6,100	(2,853)	NA	-0.19%	-0.17%	-0.53%	-0.53%	-0.60%	-3.11%	-2.95%	-2.95%	-2.86%
2015		5,560		5,560	NA	0.05%	-0.13%	-0.12%	-0.49%	-0.49%	-0.56%	-3.07%	-2.91%	-2.91%
2016				0	NA	NA	0.05%	-0.13%	-0.12%	-0.49%	-0.49%	-0.56%	-3.07%	-2.91%

Xcel Energy Common
General Network Equipment
Account 391
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002	852,835			0	0.00%	0.00%	0.00%							
2003	32,731,604			0	0.00%	0.00%	0.00%	0.00%						
2004	35,907,145			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	3,379,968			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	726,936		335	(335)	NA	-0.01%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	5,880,457			0	0.00%	-0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	10,701,667			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	(787,840)	327,097	478,143	(151,046)	19.17%	-1.52%	-0.96%	-0.92%	-0.76%	-0.27%	-0.17%	-0.17%	-0.17%	-0.17%
2010				0	NA	19.17%	-1.52%	-0.96%	-0.92%	-0.76%	-0.27%	-0.17%	-0.17%	-0.17%
2011	19,747,779	33,319	17,090	16,229	0.08%	0.08%	-0.71%	-0.45%	-0.38%	-0.37%	-0.34%	-0.18%	-0.12%	-0.12%
2012	3,602,211	38,588	799	37,789	NA	0.23%	0.23%	-0.43%	-0.29%	-0.25%	-0.24%	-0.23%	-0.12%	-0.09%
2013	21,150,757	10,776	314	10,462	NA	0.19%	0.14%	0.14%	-0.20%	-0.16%	-0.14%	-0.14%	-0.13%	-0.09%
2014	10,839,036	25,567	(4,637)	30,204	NA	0.13%	0.22%	0.17%	0.17%	-0.10%	-0.09%	-0.08%	-0.08%	-0.08%
2015	9,137,814	5,560		5,560	NA	0.18%	0.11%	0.19%	0.16%	0.16%	-0.08%	-0.07%	-0.06%	-0.06%
2016	9,493,912			0	NA	0.03%	0.12%	0.09%	0.15%	0.14%	0.14%	-0.07%	-0.06%	-0.06%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Transportation Equipment - Automobiles
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002				0	NA	NA	NA							
2003				0	NA	NA	NA	NA						
2004		75,586		75,586	NA	NA	NA	NA	NA					
2005				0	NA	NA	NA	NA	NA	NA				
2006				0	NA	NA	NA	NA	NA	NA	NA			
2007				0	NA	NA	NA	NA	NA	NA	NA	NA		
2008				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	165,915			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016		52,553		52,553	NA	31.67%	31.67%	31.67%	31.67%	31.67%	31.67%	31.67%	31.67%	31.67%

Xcel Energy Common Plant
General Transportation Equipment - Light Trucks
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002				0	NA	NA	NA							
2003				0	NA	NA	NA	NA						
2004	108,012	2,441		2,441	2.26%	2.26%	2.26%	2.26%	2.26%					
2005		43,830		43,830	NA	42.84%	42.84%	42.84%	42.84%	42.84%				
2006		5,087	91	4,996	NA	NA	47.46%	47.46%	47.46%	47.46%	47.46%			
2007		3,737		3,737	NA	NA	NA	50.92%	50.92%	50.92%	50.92%	50.92%		
2008			4,275	(4,275)	NA	NA	NA	NA	46.97%	46.97%	46.97%	46.97%	46.97%	
2009				0	NA	NA	NA	NA	NA	46.97%	46.97%	46.97%	46.97%	46.97%
2010				0	NA	NA	NA	NA	NA	NA	46.97%	46.97%	46.97%	46.97%
2011				0	NA	NA	NA	NA	NA	NA	NA	46.97%	46.97%	46.97%
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	46.97%	46.97%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	46.97%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	254,091	13,222	(12,241)	25,463	NA	10.02%	10.02%	10.02%	10.02%	10.02%	10.02%	8.34%	9.81%	11.78%
2016	2,021,256	89,804	(420)	90,224	NA	5.08%	5.08%	5.08%	5.08%	5.08%	5.08%	5.08%	4.90%	5.06%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Transportation Equipment - Trailers
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-	-	-	0	NA	NA								
2002	-	-	-	0	NA	NA	NA							
2003	-	-	-	0	NA	NA	NA	NA						
2004	-	-	-	0	NA	NA	NA	NA	NA					
2005	-	-	-	0	NA	NA	NA	NA	NA	NA				
2006	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
2007	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
2008	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013			632	(632)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	116,343			0	NA	0.00%	-0.54%	-0.54%	-0.54%	-0.54%	-0.54%	-0.54%	-0.54%	-0.54%
2016	35,980	3,431		3,431	NA	2.25%	2.25%	1.84%	1.84%	1.84%	1.84%	1.84%	1.84%	1.84%

Xcel Energy Common Plant
General Transportation Equipment - Heavy Trucks
Account 392
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002				0	NA	NA	NA							
2003				0	NA	NA	NA	NA						
2004	35,125	50,391	-	50,391	143.46%	143.46%	143.46%	143.46%	143.46%					
2005				0	NA	143.46%	143.46%	143.46%	143.46%	143.46%				
2006				0	NA	NA	143.46%	143.46%	143.46%	143.46%	143.46%			
2007				0	NA	NA	NA	143.46%	143.46%	143.46%	143.46%	143.46%		
2008				0	NA	NA	NA	NA	143.46%	143.46%	143.46%	143.46%	143.46%	
2009				0	NA	NA	NA	NA	NA	143.46%	143.46%	143.46%	143.46%	143.46%
2010				0	NA	NA	NA	NA	NA	NA	143.46%	143.46%	143.46%	143.46%
2011				0	NA	NA	NA	NA	NA	NA	NA	143.46%	143.46%	143.46%
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	143.46%	143.46%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	143.46%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015		21,032	(1,056)	22,088	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016		20,136		20,136	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Stores Equipment
Account 393
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-	-	-	0	NA	NA								
2002	-	-	-	0	NA	NA	NA							
2003	125,531	-	-	0	0.00%	0.00%	0.00%	0.00%						
2004	51,469	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	69,759	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	165,198	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	113,152	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	351,877	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	43,860			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	9,329			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2014				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015				0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016	12,021			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Common Plant
General Tools, Shop & Garage Equipment
Account 394
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002	271,426			0	0.00%	0.00%	0.00%							
2003	126,619			0	0.00%	0.00%	0.00%	0.00%						
2004	236,890	5,379		5,379	2.27%	1.48%	0.85%	0.85%	0.85%					
2005	568,743			0	NA	0.67%	0.58%	0.45%	0.45%	0.45%				
2006	139,917	12,259	2,642	9,617	NA	1.36%	1.59%	1.40%	1.12%	1.12%	1.12%			
2007	368,342			0	0.00%	1.89%	0.89%	1.14%	1.04%	0.88%	0.88%	0.88%		
2008	98,515			0	0.00%	0.00%	1.58%	0.82%	1.06%	0.97%	0.83%	0.83%	0.83%	
2009	291,266			0	0.00%	0.00%	0.00%	1.07%	0.66%	0.88%	0.82%	0.71%	0.71%	0.71%
2010	-			0	NA	0.00%	0.00%	0.00%	1.07%	0.66%	0.88%	0.82%	0.71%	0.71%
2011	170,079		7,103	(7,103)	-4.18%	-4.18%	-1.54%	-1.27%	-0.77%	0.24%	0.15%	0.42%	0.39%	0.35%
2012	66,031			0	NA	-3.01%	-3.01%	-1.35%	-1.13%	-0.71%	0.22%	0.15%	0.41%	0.38%
2013	334,636		20,310	(20,310)	NA	-5.07%	-4.80%	-4.80%	-3.18%	-2.85%	-2.06%	-1.21%	-0.87%	-0.55%
2014				0	NA	-6.07%	-5.07%	-4.80%	-4.80%	-3.18%	-2.85%	-2.06%	-1.21%	-0.87%
2015	145,898			0	NA	0.00%	-4.23%	-3.72%	-3.83%	-3.83%	-2.72%	-2.48%	-1.86%	-1.10%
2016	3,890			0	NA	0.00%	0.00%	-4.19%	-3.69%	-3.80%	-3.80%	-2.71%	-2.47%	-1.85%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common
General Laboratory Equipment
Account 395
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-	-	-	0	NA	NA								
2002	26,373	-	-	0	0.00%	0.00%	0.00%							
2003	-	-	-	0	NA	0.00%	0.00%	0.00%						
2004	9,610	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-	-	-	0	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	-	-	-	0	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	-	-	-	0	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	-	-	-	0	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	36,686			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Xcel Energy Common Plant
General Power Operated Equipment
Account 396
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-	-	-	0	NA	NA								
2002	-	-	-	0	NA	NA	NA							
2003	-	-	-	0	NA	NA	NA	NA						
2004	-	-	-	0	NA	NA	NA	NA	NA					
2005	-	-	-	0	NA	NA	NA	NA	NA	NA				
2006	-	-	-	0	NA	NA	NA	NA	NA	NA	NA			
2007	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA		
2008	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
2009	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2011	-	-	-	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014				0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	4,968			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Communication Equipment
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000				0	NA									
2001				0	NA	NA								
2002	2,147,381			0	0.00%	0.00%	0.00%							
2003	-			0	#VALUE!	0.00%	0.00%	0.00%						
2004	5,675,203			0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	7,019,641			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	734,267			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	189,472			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
2008	127,474			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2009	1,147,802			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2010				0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2011	1,105,612			0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2012	109,489			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2013	44,115		150	(150)	NA	-0.10%	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%	0.00%	0.00%	0.00%
2014	545,824			0	NA	-0.03%	-0.02%	-0.01%	-0.01%	-0.01%	0.00%	0.00%	0.00%	0.00%
2015	59,122			0	NA	0.00%	-0.02%	-0.02%	-0.01%	-0.01%	0.00%	0.00%	0.00%	0.00%
2016	24,140	12,270		12,270	NA	14.74%	1.95%	1.80%	1.55%	0.64%	0.64%	0.40%	0.38%	0.36%

Xcel Energy Common Plant
General Communication Equipment - AES
Account 397
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-	-	-	0	NA	NA								
2002	3,669,806	-	-	0	0.00%	0.00%	0.00%							
2003	380,447	-	-	0	0.00%	0.00%	0.00%	0.00%						
2004	836,004	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	490,062	-	-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	-	-	-	0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	2,720,952	-	395,655	(395,655)	-14.54%	-14.54%	-12.32%	-9.78%	-8.94%	-4.89%	-4.89%	-4.89%		
2008	97,882	-	-	0	0.00%	-14.04%	-14.04%	-11.96%	-9.55%	-8.74%	-4.83%	-4.83%	-4.83%	
2009	-	-	-	0	NA	0.00%	-14.04%	-14.04%	-11.96%	-9.55%	-8.74%	-4.83%	-4.83%	-4.83%
2010	-			0	NA	NA	0.00%	-14.04%	-14.04%	-11.96%	-9.55%	-8.74%	-4.83%	-4.83%
2011	3,562,640			0	0.00%	0.00%	0.00%	0.00%	-6.20%	-6.20%	-5.76%	-5.13%	-4.89%	-3.37%
2012	188,021			0	NA	0.00%	0.00%	0.00%	0.00%	-6.02%	-6.02%	-5.60%	-5.01%	-4.78%
2013	42,946			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	-5.98%	-5.98%	-5.57%	-4.98%
2014	3,253			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-5.98%	-5.98%	-5.57%
2015	59,122			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-5.93%	-5.93%
2016	3,633,035			0	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-3.84%

NA - Not Applicable

Northern States Power Company - Minnesota: Transmission, Distribution & General Study

Xcel Energy Common Plant
General Miscellaneous Equipment
Account 398
2000-2016

Transaction Year	Transactional History Retirements	Salvage	Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
2000	-			0	NA									
2001	-		-	0	NA	NA								
2002	225,190		-	0	0.00%	0.00%	0.00%							
2003	1,875		-	0	0.00%	0.00%	0.00%	0.00%						
2004	7,482		-	0	0.00%	0.00%	0.00%	0.00%	0.00%					
2005	54,187		-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
2006	145,815		-	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
2007	164,511		7,622	(7,622)	-4.63%	-2.46%	-2.09%	-2.05%	-2.04%	-1.27%	-1.27%	-1.27%		
2008	42,440		-	0	0.00%	-3.68%	-2.16%	-1.87%	-1.84%	-1.83%	-1.19%	-1.19%	-1.19%	
2009	35,714		-	0	0.00%	0.00%	-3.14%	-1.96%	-1.72%	-1.69%	-1.69%	-1.13%	-1.13%	-1.13%
2010	-		-	0	NA	0.00%	0.00%	-3.14%	-1.96%	-1.72%	-1.69%	-1.69%	-1.13%	-1.13%
2011	18,100	0	6003	(6,003)	-33.17%	-33.17%	-11.16%	-6.24%	-5.22%	-3.35%	-2.96%	-2.91%	-2.90%	-1.96%
2012			(1,501)	1,501	NA	-24.87%	-24.87%	-8.37%	-4.68%	-4.65%	-2.98%	-2.63%	-2.59%	-2.58%
2013	237,763			0	NA	0.63%	-1.76%	-1.76%	-1.54%	-1.35%	-2.43%	-1.88%	-1.74%	-1.72%
2014				0	NA	0.00%	0.63%	-1.76%	-1.76%	-1.54%	-1.35%	-2.43%	-1.88%	-1.74%
2015	46,651		1,002	(1,002)	NA	-2.15%	-0.35%	0.18%	-1.82%	-1.82%	-1.63%	-1.45%	-2.41%	-1.90%
2016	57,878			0	NA	-0.96%	-0.96%	-0.29%	0.15%	-1.53%	-1.53%	-1.39%	-1.26%	-2.18%

NA - Not Applicable

Northern States Power Company - South Dakota: Transmission, Distribution & General

Schedule 8 - Depreciation and Amortization Rate Calculations

Xcel Energy
Summary of Annual Depreciation and Amortization Accruals
Electric Utility
Excluding Fully Accrued Assets

FERC Account	Account Description	Adjusted Plant 1/1/2022	Depreciation Reserve 1/1/2022	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unacrrued Balance	Proposed Average Remaining Life (Yrs)	Annual Accrual	Depreciation/ Amortization Rate	Reserve Ratio	
Intangible Plant - Total Company											
302	Franchise and Consents	$ 263,661,738	$ 118,407,518	0%	-	$ 145,254,220	Note (1)	$ 13,183,087	5.00%	44.91%	
303	Computer Software 3 Year	1,947,857	280,526	0%	-	1,667,332	2.50	666,933	34.24%	14.40%	
303	Computer Software 5 Year	91,334,705	33,904,271	0%	-	57,430,434	2.85	20,136,511	22.05%	37.12%	
303	Computer Software 7 Year	-	-	0%	-	-	0.00	-	14.29%	0.00%	(3)
303	Computer Software 10 Year	57,816	7,494	0%	-	50,322	8.50	5,920	10.24%	12.96%	
303	Computer Software 15 Year	-	-	0%	-	-	0.00	-	6.67%	0.00%	(3)
	Total Intangible Plant	357,002,117	152,599,809		-	204,402,308		33,992,451			
Transmission - Total Company											
352	Structures and Improvements	154,713,001	29,216,651	-5%	(7,735,650)	133,231,999	58.77	2,267,001	1.47%	18.88%	
353	Station Equipment	1,453,096,963	414,338,177	-15%	(217,964,545)	1,256,723,331	43.62	28,813,389	1.98%	28.51%	
354	Towers and Fixtures	126,526,815	87,546,689	-35%	(44,284,385)	83,264,512	40.72	2,044,848	1.62%	69.19%	
355	Poles and Fixtures	1,546,910,331	374,007,369	-50%	(773,455,165)	1,946,358,127	53.09	36,662,927	2.37%	24.18%	
356	Overhead Conductors and Devices	672,055,789	146,903,207	-35%	(235,219,526)	760,372,108	57.33	13,264,130	1.97%	21.86%	
357	Underground Conduit	32,181,582	6,658,359	0%	-	25,523,223	59.53	428,741	1.33%	20.69%	
358	Underground Conductor and Devices	35,447,885	10,982,030	-5%	(1,772,394)	26,238,250	36.84	712,153	2.01%	30.98%	
359	Roads and Trails	-	-	0%	-	-	0.00	-	1.67%	0.00%	(3)
	Total Transmission	4,020,932,365	1,069,652,481		(1,280,431,666)	4,231,711,549		84,193,190			
Distribution - SD Only											
361	Structures and Improvements	4,774,434	1,087,693	-30%	(1,432,330)	5,119,071	53.15	96,322	2.02%	22.78%	
362	Station Equipment	46,201,752	16,556,235	-25%	(11,550,438)	41,195,955	39.44	1,044,580	2.26%	35.83%	
364	Poles, Towers, and Fixtures	57,033,380	25,380,898	-120%	(68,440,056)	100,092,537	38.51	2,598,876	4.56%	44.50%	
365	Overhead Conductors and Devices	56,800,634	14,546,887	-25%	(14,200,158)	56,453,905	31.87	1,771,511	3.12%	25.61%	
366	Underground Conduit	21,870,951	7,192,353	-20%	(4,374,190)	19,052,788	42.30	450,404	2.06%	32.89%	
367	Underground Conductor and Devices	109,364,157	30,351,931	-10%	(10,936,416)	89,948,642	37.96	2,369,257	2.17%	27.75%	
368	Line Transformers	27,593,083	3,073,308	-5%	(1,379,654)	25,899,429	19.59	1,321,950	4.79%	11.14%	
368	Line Capacitors	2,302,042	225,930	-7%	(161,143)	2,237,255	16.62	134,630	5.85%	9.81%	
369	Overhead Services	5,544,904	4,725,474	-85%	(4,713,168)	5,532,599	24.73	223,719	4.03%	85.22%	
369	Underground Services	26,230,679	10,471,693	-5%	(1,311,534)	17,070,520	29.07	587,278	2.24%	39.92%	
369	Electric Vehicle Supply Infrastructure	-	-	0%	-	-	0.00	-	10.00%	0.00%	(3)
370	Meters	3,175,492	478,434	-5%	(158,775)	2,855,832	7.13	400,415	12.61%	15.07%	
370	Meters - AGIS	-	-	0%	-	-	0.00	-	5.00%	0.00%	(3)
370	Electric Vehicle Chargers	-	-	0%	-	-	0.00	-	10.00%	0.00%	(3)
373	Street Lighting and Signal Systems	3,695,470	990,619	-40%	(1,478,188)	4,183,040	24.04	173,977	4.71%	26.81%	
	Total Distribution - SD only	$ 364,586,978	$ 115,081,457		$ (120,136,050)	$ 369,641,572		$ 11,172,920			
General - Total Company											
390	Structures and Improvements	30,686,732	8,112,394	-20%	(6,137,346)	28,711,684	42.96	668,312	2.18%	26.44%	
390	Structures and Improvements (Specific)	44,465,557	20,237,353	-20%	(8,893,111)	33,121,315	Note (5)	759,883	Note (5)	45.51%	
390	Structures and Improvements - Leasehold Improvements	1,075,433	399,575	0%	-	675,858	6.28	107,543	10.00%	37.15%	(2)
391	Office Furniture and Equipment	33,722,960	20,895,689	0%	-	12,827,271	8.54	1,501,576	4.45%	61.96%	
391	Network Equipment	58,083,121	28,199,500	0%	-	29,883,621	3.34	8,951,969	15.41%	48.55%	
392	Automobiles	7,191,147	2,901,729	5%	359,557	3,929,861	6.13	641,457	8.92%	40.35%	
392	Light Trucks	26,572,221	11,917,847	10%	2,657,222	11,997,152	5.43	2,209,904	8.32%	44.85%	
392	Trailers	22,576,740	10,780,806	20%	4,515,348	7,280,586	5.40	1,347,498	5.97%	47.75%	
392	Heavy Trucks	109,725,664	54,606,353	15%	16,458,850	38,660,461	5.54	6,978,996	6.36%	49.77%	
393	Stores Equipment	1,531,915	1,073,172	0%	-	458,743	7.22	63,538	4.15%	70.05%	
394	Tools, Shop, and Garage Equipment	115,912,416	56,996,785	0%	-	58,915,632	8.25	7,138,657	6.16%	49.17%	
395	Laboratory Equipment	2,452,051	1,551,334	0%	-	900,716	4.18	215,256	8.78%	63.27%	
396	Power Operated Equipment	48,941,521	29,024,734	15%	7,341,228	12,575,558	4.25	2,958,987	6.05%	59.30%	
397	General Communication Equipment	57,388,210	8,051,675	0%	-	49,336,534	8.71	5,664,864	9.87%	14.03%	
397	Communication Equipment - Two Way	63,558,076	29,519,419	0%	-	34,038,657	5.77	5,903,582	9.29%	46.44%	
397	Comm. & Telecomm. Equipment - AES	6,663,947	5,516,810	0%	-	1,147,137	3.54	324,449	4.87%	82.79%	
397	Comm. & Telecomm. Equipment - EMS	46,455,878	22,884,481	0%	-	23,571,397	8.26	2,853,254	6.14%	49.26%	
397	Communication Equipment - Smart Grid	9,133,832	459,070	0%	-	8,674,762	19.08	454,567	4.98%	5.03%	
398	Miscellaneous Equipment	1,902,512	659,063	0%	-	1,243,449	10.21	121,754	6.40%	34.64%	
	Total General	688,039,931	313,787,789		16,301,747	357,950,394		48,866,046			
	Total Electric Utility	$ 5,430,561,391	$ 1,651,121,537		$ (1,384,265,968)	$ 5,163,705,823		$ 178,224,606			

Northern States Power Company - South Dakota: Transmission, Distribution & General

Schedule 8 - Depreciation and Amortization Rate Calculations

Xcel Energy
Summary of Annual Depreciation and Amortization Accruals
Common Utility
Excluding Fully Accrued Assets

FERC Account	Account Description	Adjusted Plant 1/1/2022	Depreciation Reserve 1/1/2022	Est. Future Net Salvage %	Est. Future Net Salvage Amount	Unacrrued Balance	Proposed Average Remaining Life (Yrs)	Annual Accrual	Depreciation/ Amortization Rate	Reserve Ratio	
Intangible Plant - Total Company											
301	Intangible Organization Costs	$ 100,608	$ -	0%	$ -	$ 100,608	Note (4)	$ -	0.00%	0.00%	
302	Franchise and Consents	-	-	0%	-	-	Note (1)	$ -	5.00%	0.00%	
303	Computer Software 3 Year	10,069,404	5,087,300	0%	-	4,982,105	1.42	3,496,297	34.72%	50.52%	
303	Computer Software 5 Year	181,993,525	80,461,367	0%	-	101,532,157	2.70	37,638,716	20.68%	44.21%	
303	Computer Software 7 Year	19,026,956	3,953,610	0%	-	15,073,346	5.50	2,740,608	14.40%	20.78%	
303	Computer Software 10 Year	12,895,920	6,119,450	0%	-	6,776,470	4.67	1,452,194	11.26%	47.45%	
303	Computer Software 15 year	164,669,147	51,013,122	0%	-	113,656,025	10.12	11,236,187	6.82%	30.98%	
	Total Intangible Plant	388,755,560	146,634,849		-	242,120,711		56,564,002			
General - Total Company											
390	Structures and Improvements	72,505,182	10,520,608	-25%	(18,126,296)	80,110,870	43.38	1,846,538	2.55%	14.51%	
390	Structures and Improvements (Specific)	132,502,455	20,136,370	-25%	(33,125,614)	145,491,699	Note (5)	3,618,253	Note (5)	15.20%	
390	Structures and Improvements - Leasehold Improvements	18,120,375	5,759,462	0%	-	12,360,914	9.57	1,292,217	7.13%	31.78%	(2)
391	Office Furniture and Equipment	22,521,905	11,163,533	0%	-	11,358,372	11.24	1,010,886	4.49%	49.57%	
391	Network Equipment	146,440,286	76,959,830	0%	-	69,480,455	2.68	25,910,090	17.69%	52.55%	
392	Automobiles	1,329,002	853,742	5%	66,450	408,810	4.04	101,149	7.61%	64.24%	
392	Light Trucks	3,444,200	1,507,774	10%	344,420	1,592,006	5.70	279,442	8.11%	43.78%	
392	Trailers	511,861	179,129	20%	102,372	230,360	7.41	31,083	6.07%	35.00%	
392	Heavy Trucks	4,573,684	1,805,930	15%	686,053	2,081,701	7.05	295,365	6.46%	39.49%	
393	Stores Equipment	246,162	117,440	0%	-	128,722	11.67	11,035	4.48%	47.71%	
394	Tools, Shop, and Garage Equipment	8,212,669	2,841,063	0%	-	5,371,605	10.44	514,455	6.26%	34.59%	
395	Laboratory Equipment	-	-	0%	-	-	0.00	-	10.00%	0.00%	(3)
396	Power Operated Equipment	1,300,138	625,585	15%	195,021	479,532	5.79	82,871	6.37%	48.12%	
397	Comm. & Telecomm. Equipment	363,736	173,780	0%	-	189,956	5.57	34,124	9.38%	47.78%	
397	Communication Equipment - Two Way	76,870	48,400	0%	-	28,470	4.50	6,327	8.23%	62.96%	
397	Communication Equipment - Smart Grid	-	-	0%	-	-	0.00	-	5.00%	0.00%	(3)
398	Miscellaneous Equipment	179,282	173,593	0%	-	5,689	1.19	4,798	2.68%	96.83%	
	Total General	412,327,809	132,866,239		(49,857,594)	329,319,163		35,038,634			
	Total Common Utility	801,083,369	279,501,089		(49,857,594)	571,439,874		91,602,636			
	Total - All Utilities	$ 6,231,644,760	$ 1,930,622,625		$ (1,434,123,562)	$ 5,735,145,697		$ 269,827,242			

(1) Account 302 is amortized over the terms of the franchise agreements or license, which is typically 20 years. The Company is including Account 302 in all schedules for completeness.
(2) Depreciated over lease term.

(3) Currently there is no balance in these accounts. In the event plant is added to these accounts, the Company is requests authorization to use the depreciation rate proposed based on the proposed parameters for each account.
(4) Account 301 is not amortized. The Company is including Account 301 in all schedules for completeness.

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking

Docket No. EL22-___
Schedule 09
Page 1 of 1

2023 South Dakota ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$817,396	$4,620,271	$3,802,875
Prairie Island Unit 1	143,872	2,051,067	1,907,195
Prairie Island Unit 2	272,983	1,521,292	1,248,309
TOTAL	$1,234,251	$8,192,630	$6,958,378

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917
Email: felicel@michigan.gov

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
Metro Square, Suite 350
121 7th Place East
St. Paul, MN 55101-2147
Email: will.seuffert@state.mn.us

Mr. Steve Kahl
Executive Secretary
North Dakota Public Service Commission
600 E Boulevard, Dept. 408
Bismarck, ND 58505-0480
Email: ndpsc@nd.gov

Ms. Patricia Van Gerpen
Executive Director
Public Utilities Commission of South Dakota
500 East Capitol Ave.
Pierre, SD 57501-5070
Email: patty.vangerpen@state.sd.us

Mr. Cru Stubley
Secretary to the Commission
Public Service Commission of Wisconsin
4822 Madison Yards Way
North Tower - 6th Floor
Madison, Wisconsin 53705-9100
Email: Cru.Stubley@wisconsin.gov

Ms. Natalie Y. Tingle-Stewart, Director
Division of Electric Power Regulation (Central)
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, DC 20426
Email: Natalie.tingle-stewart@ferc.gov

FERC rendition of the electronically filed tariff records in Docket No. ER24-01472-000
Filing Data:
CID: C000824
Filing Title: 2024 Interchange Agreement Annual Filing
Company Filing Identifier: 1137
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: Production Tariffs
Tariff ID: 1001
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Exhibits, Rate Schedules, 0.14.0, A
Record Narative Name:
Tariff Record ID: 200
Tariff Record Collation Value: 5294080 Tariff Record Parent Identifier: 195
Proposed Date: 2024-01-01
Priority Order: 1000000000
Record Change Type: CHANGE
Record Content Type: 1
Associated Filing Identifier:

Exhibits

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit I**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF POWER SALES

The Monthly amounts of sales of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Power Sales (PS) to NSP(Wis):

$$\text{PS to NSP(Wis)} = \text{NSP(Minn) Demand} \times \frac{\text{NSP(Wis) Demand}}{\text{System Demand}}$$

B - NSP(Wis) Power Sales (PS) to NSP(Minn):

$$\text{PS to NSP(Minn)} = \text{NSP(Wis) Demand} \times \frac{\text{NSP(Minn) Demand}}{\text{System Demand}}$$

Where:

"PS" is the amount of power sold in MW by the selling Party to the purchasing Party in the billing month.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months on historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.960 for NSP(Minn)
0.952 for NSP(Wis)

"System Demand" equals NSP(Minn) Demand + NSP(Wis) Demand

Exhibit VIII shows an example of the development of the power sales.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit II**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF AMOUNTS OF ENERGY SALES

The monthly amounts of sales of energy by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Sales (ES) to NSP(Wis):

$$\text{ES to NSP(Wis)} = \text{NSP(Minn) Energy Requirements} \times \frac{\text{NSP(Wis) Energy Requirements}}{\text{System Energy Requirements}}$$

B - NSP(Wis) Energy Sales (ES) to NSP(Minn):

$$\text{ES to NSP(Minn)} = \text{NSP(Wis) Energy Requirements} \times \frac{\text{NSP(Minn) Energy Requirements}}{\text{System Energy Requirements}}$$

Where:

"ES" is the amount of energy sold in Mwh's by the selling Party to the purchasing Party in the billing month.

"Energy Requirements" are each Party's billing requirements in Mwh's for the current month, excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes. [1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.959 for NSP(Minn)
0.946 for NSP(Wis)

"System Energy Requirements" equals the total of NSP(Minn) and NSP(Wis) Energy Requirements.

[1/] Including, but not limited to, the NSP (Minn) Renewable*Connect program.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit III**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR POWER SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Demand Rate for sales to NSP(Wis):

$$\text{DR to NSP(Wis)} = \frac{\text{NSP(Minn) Demand Costs}}{\text{NSP(Minn) Demand}}$$

B - NSP(Wis) Demand Rate for sales to NSP(Minn):

$$\text{DR to NSP(Minn)} = \frac{\text{NSP(Wis) Demand Costs}}{\text{NSP(Wis) Demand}}$$

Where:

"DR" is the monthly unit demand rate (rate in dollars per MW) for power sales by each Party to other Parties.

"Demand Costs" are the demand related costs developed for each Party for the billing month under Exhibit V.

"Demand" is each Party's billing demand in MW's based on the average of 36 Monthly Coincident Peaks; including 18 months of historical peaks and 18 months of forecasted peak data for the year of application. The measured monthly coincident peak demands shall be adjusted by a Transmission Loss Multiplier. Historical peak data may be adjusted to reflect known significant load changes over 10 MW by agreement of the Parties.

"Transmission Loss Multipliers" are equal to:

0.960 for NSP(Minn)
0.952 for NSP(Wis)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IV**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF UNIT RATES FOR ENERGY SALES

The monthly unit rates for the sales of megawatts of power by each Party to the other Party shall be determined as follows:

A - NSP(Minn) Energy Rates for sales to NSP(Wis):

$$\text{ER to NSP(Wis)} = \frac{\text{NSP(Minn) Energy Costs}}{\text{NSP(Minn) Energy Requirements}}$$

B - NSP(Wis) Energy Rates for sales to NSP(Minn):

$$\text{ER to NSP(Minn)} = \frac{\text{NSP(Wis) Energy Costs}}{\text{NSP(Wis) Energy Requirements}}$$

Where:

"ER" is the monthly unit energy rate (rate in dollars per Mwh) for energy sales from each Party to the other Parties.

"Energy Costs" are each Party's energy costs for the billing month, including the carrying costs on Electric Production Fuel Stock balances recorded in FERC Accounts 151 and 152 included at 100 percent of the average of the monthly balances in the accounts.

"Energy Requirements" are each Party's billing requirements in MWH's for the current month excluding energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/] The measured monthly energy requirements shall be adjusted by a Transmission Loss Multiplier.

"Transmission Loss Multipliers" are equal to:

0.959 for NSP(Minn)
0.946 for NSP(Wis)

[1/] Including, but not limited to, the NSP (Minn) Renewable*Connect program.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit V**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

The demand related cost used in Exhibit III shall be those developed on line 23 of this exhibit.

	DEVELOPMENT OF RATE BASE	NSP(Minn)	NSP(Wis)
1.	Electric Plant in Service (Sched. 1)		
1.1	Pre-funded Allowance for Funds Used during Construction (Sched. 1.1)		
1.2	Electric Plant Acquisition Adjustments (Sched. 1.2)		
2.	Accumulated Provision for Depreciation (Sched. 2)		
2.1	Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments (Sched. 2.1)		
3.	Net Electric Plant in Service		
4.	Deduct: Accumulated Deferred Income Taxes (Sched. 3)		
5.	Add: Plant Held for Future Use (Sched. 4)		
6.	Add: Electric Construction Work in Progress (Sched. 4.1)		
6.1	Add: Accumulated Amortization of Theoretical Reserve Surplus (Sched. 4.2)		
7.	Rate Base (Total lines 1 through 6.1)		

COST OF SERVICE - DEMAND RELATED

A. Fixed Charges on Investment

8. Return on Rate Base at Specified Rate of Return (Sched. 6)
9. Income Taxes (Sched. 7)
10. Depreciation & Amortization Expense (Sched. 8)
10.1 Theoretical Reserve Surplus Amortization Expense (Sched. 8.1)
10.2 Prairie Island Extended Power Uprate Amortization Revenue Requirement (Sched. 8.2)
10.3 Monticello Life Cycle Management / Extended Power Uprate Project Return on Rate Base Adjustment (Sched. 8.3)
10.4 Benson Power Termination Amortization Revenue Requirement (Sched. 8.4)
11. Deferred Income Taxes (Sched. 9)
12. Property Taxes (Sched. 10)
13. Insurance (Sched. 11)
13.1 Carrying Cost on Demand-Related Deferred Nuclear Refueling Outage Costs
14. Total Fixed Charges (Total lines 8 through 13.1)

B. Fixed Power Production and Regional Market Expense

15. Fixed Operating and Maintenance Expense (Sched. 12 and 12.1)
16. Net Purchased Power Demand Costs (Sched. 13)
17. Production System Control & Load Dispatching (Sched. 14)
18. Credits for Production Related Services (Sched. 16)
19. Total Fixed Power Production Expense (Total lines 15 through 18)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit V**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF DEMAND RELATED COSTS

C. Fixed Transmission Expense

20. Operation and Maintenance Expense (Sched. 15)
21. Credits for Transmission Related Services (Sched. 17)
22. Total Fixed Transmission Expense (Total lines 20 through 21)
23. Total Month's Demand Related Costs (Total lines 14, 19 and 22)

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 1

ELECTRIC PLANT IN SERVICE

Electric Plant In Service included for the determination of charges among the Parties shall include the average monthly balances of gross plant at original cost. Electric Plant in Service balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs. The following FERC Accounts shall be included:

1. Intangible Plant Investment
   Water power and nuclear plant relicensing investment recorded in FERC Account 302. Intangible software directly related to the production and transmission functions recorded in FERC Account 303 and as agreed among the Parties.

2. Production Plant Investment
   Production plant investment recorded in FERC Accounts 310 through 348.

3. Nuclear Fuel Plant Investment
   Nuclear fuel investment included in FERC Accounts 120.2, 120.4 and 120.6.

4. Transmission Plant Investment
   Transmission plant investment recorded in FERC Accounts 350 through 359. Transmission substations having facilities which jointly serve the transmission and distribution functions are inventoried and priced according to the function served. The original cost value of the distribution facilities are excluded from these accounts for the purpose of this Agreement.

5. Distribution Substation Plant Investment
   Distribution substation plant investment recorded in FERC Accounts 360, 361 and 362. Distribution substations having facilities which jointly serve the distribution and transmission functions are inventoried and priced according to the function served. The original cost value of only the facilities which serve a transmission function are included for the purposes of this Agreement.

6. General Plant Investment
   System control and load dispatching plant investment recorded in FERC Account 397. System control and load dispatching equipment is analyzed as to the function it serves. The original cost value of the equipment serving the production and transmission functions is included for the purposes of this Agreement.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.1

PRE-FUNDED ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Pre-funded Allowance for Funds Used during Construction (AFUDC) is an offsetting AFUDC calculation incorporating the effect of specific regulation whereby customers of a particular jurisdiction are paying for the financing costs during the construction phase of a project. Pre-funded AFUDC is accumulated in FERC Account 253. The amounts included to determine the charges among the Parties shall include those FERC jurisdictional amounts related to the transmission function whereby a current return is earned through the Midcontinent Independent System Operator, Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachment GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 1.2

ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Electric Plant Acquisition Adjustments is recorded in FERC Account 114. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2

ACCUMULATED PROVISION FOR DEPRECIATION

Accumulated Provision for Depreciation for Electric Plant in Service and Nuclear Fuel is recorded in FERC Accounts 108 and 120.5, respectively. Accumulated provision for amortization of electric utility plant is recorded in FERC Account 111. Accumulated Provision for Depreciation balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

These accounts are classified to the intangible, production, nuclear fuel, transmission, distribution and general functions of plant and the amounts are calculated based upon the original cost of the plant. The annual charge to the accumulated provisions for depreciation reflects the annual depreciation provisions, book cost of plant retired, cost of removal and salvage credit.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 2.1

ACCUMULATED PROVISION FOR AMORTIZATION OF ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Accumulated Provision for Amortization of Electric Plant Acquisition Adjustments is recorded in FERC Account 115. The amounts included to determine the charges among the Parties shall include those amounts related to the production function and as agreed among the Parties.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 3

ACCUMULATED DEFERRED INCOME TAXES

Accumulated Deferred Income Taxes included in FERC Accounts 190 and 281-283 are classified to the intangible, production, nuclear fuel, transmission, distribution and general plant functions in the same detail as the original cost of the plant in service. Accumulated Deferred Income Tax balances will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4

PLANT HELD FOR FUTURE USE - LAND

Land Plant Held for Future Use if recorded in FERC Account 105. The amounts included to determine the charges among the Parties shall include those amounts related to the production and transmission functions. These amounts shall be included at 100% of the average monthly balances as recorded on the Company's books and records.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 4.1

ELECTRIC CONSTRUCTION WORK IN PROGRESS

Electric Construction Work in Progress is recorded in FERC Account 107. Electric Construction Work in Progress included for the determination of charges among the Parties shall include the average monthly construction expenditure balance limited to the net FERC jurisdictional portion of transmission projects that earn a current return through the Midcontinent Independent System Operator, Inc.'s (MISO) application of FERC Order 679 under Attachment O-NSP and Attachments GG and MM of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) and excluding AFUDC incurred post project eligibility as approved by FERC under the MISO Tariff.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 4.2**

ACCUMULATED AMORTIZATION OF THEORETICAL RESERVE SURPLUS

Accumulated Amortization of Theoretical Reserve Surplus is recorded in FERC Account 182.3 in accordance with the Minnesota Public Utilities Commission (MPUC) decision (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013) to amortize the NSP (Minn) theoretical reserve surplus (as developed in the table below) beginning January 1, 2013 over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant to be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. The regulatory asset set-up was completed at the end of 2016 as detailed in the table below.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates of the regulatory asset created through the amortization of the NSP (Minn) theoretical reserve surplus, effective January 1, 2017.

The accumulated amortization amounts are based on the schedule provided in Exhibit V, Schedule 8.1.

Balances as of 12/31/2016			
Functional Class	**Total NSP (Minn) Actual to Theoretical Reserve Difference**	**NSP (Minn) State of Minnesota Actual to Theoretical Reserve Difference**	**NSP (Wis) Actual to Theoretical Reserve Difference**
Intangible 1/	$417,044	$365,054	$0
Transmission	200,466,880	149,597,398	26,645,321
Distribution 2/	109,362,353	109,362,353	18,051
General	6,727,378	5,888,716	10,899
Total Electric Utility	$316,973,655	$265,213,520	$26,674,271

Notes:

1/ No Intangible reserve to NSP (Wis).
2/ Distribution reserve difference included under “NSP (Wis) Actual to Theoretical Reserve Difference” relates to Distribution serving system generation.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 5

OTHER

The proceeds of U.S. Environmental Protection Agency (EPA) emission allowance auctions recorded in FERC 411.8 and collected by either company shall be allocated annually as a credit to such Party's Demand Costs in Exhibit III.

In the event either Party experiences a new type of cost not anticipated by this Exhibit V, the cost shall be allocated as a Demand Cost or Energy Cost in a manner consistent with the FERC Uniform System Accounts in effect from time to time.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 6

RETURN ON RATE BASE

The return on rate base shall be the overall rate of return developed from the long term debt and preferred stock costs (if any) determined according to this schedule and the rate of return on equity specified in Exhibit VII. The capital structure for NSP(Minn) and NSP(Wis) and the appropriate cost rates shall be determined for each calendar year in the following steps:

The debt and preferred stock (if any) of NSP (Minn) and NSP(Wis) is directly assigned to each company. The cost rates for these components of the capital structure are the actual cost rates of each company's debt and preferred stock (if any) determined in accordance with FERC regulatory principles. The retained earnings portion of each company's common equity is also directly assigned to the such company. Each company's equity capital shall equal total capitalization less the debt and preferred stock (if any) directly assigned. The return on equity derived pursuant to this Schedule 6 and provided for in Exhibit VII is used as the cost of the subsidiary's retained earnings.

Unless otherwise agreed and accepted for filing by FERC, the cost rate for common equity for NSP(Minn) and NSP(Wis) will be equal. The capitalization ratios and cost rates for debt and preferred stock (if any) will be distinct between companies based on their specific level and cost of financing.

Equity Return:

By December 15 of each year, the NSP Companies shall file a revised Exhibit VII containing a rate of return on common equity equal to the quarterly adjusted generic return on common equity promulgated by FERC for effectiveness on November 1 of that year. See, *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket No. RM84-15-000, Order No. 420, issued May 20, 1985. No filing shall be required if the quarterly adjusted generic rate of return effective on November 1 is the same as the quarterly adjusted generic rate of return effective on November 1 of the previous year. In making such filing, the NSP Companies shall request that the revised Exhibit VII shall be made effective as of January 1 of the year following the filing and shall request waiver of the 60 day notice-of-filing period to achieve such effective date. After the revised Exhibit VII has been allowed to become effective, the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after the date that the filing is permitted to become effective. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Within 30 days of the filing of a revised Exhibit VII, the NSP Companies shall have the right to petition the Commission for a determination that the NSP Companies' risks are sufficiently above or below industry average risks to warrant a rate of return on common equity above or below the generic rate of return on common equity contained in such filing. The proponent of any departure from the generic rate of return on common equity contained in the filing shall bear the burden of justifying the departure.

If the Commission after hearing on the record finds that a departure is justified, it shall establish a just and reasonable rate of return on common equity for the pertinent calendar year. Such rate of return on common equity shall be made retroactively effective as of January 1 of the pertinent calendar year, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on and after that date to the rate of return on common equity determined by the Commission for the calendar year.

If, for whatever reason, FERC ceases to issue or fails to issue a quarterly adjusted generic rate of return on common equity effective for November 1 of a year, the NSP Companies shall file with FERC by December 15 of the year, or such date after January 1 determined by the Coordinating Committee, either a revised Exhibit VII or the existing Exhibit VII with a request that it be allowed to become effective as of January 1 of such year. The rate of return on common equity proposed in a filing shall be in the NSP Companies' sole discretion. NSP shall bear the burden of justifying any increase or decrease in the rate of return on common equity. The NSP Companies shall request that any determination by FERC on such filing shall be made effective as of January 1 of the year of the filing, and the NSP Companies shall make such payments among themselves as may be required to adjust billings for sales made on or after the effective date of the determination. Such payments among the NSP Companies shall be with interest at the rate provided in the Commission's regulations.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

COMPUTATION OF FEDERAL AND STATE INCOME TAXES

The Federal and State Income Taxes shall be computed as follows:

1. Required Return on Rate Base (Schedule 6)
2. Add: Book Depreciation and Amortization (Schedule 8)
3. Provision for Deferred Income Taxes (Schedule 9)
4. Deduct: Investment Tax Credit Flow Through (Schedule 7, Page 3 of 3)
4.1 Production Tax Credit (Schedule 7, Page 3 of 3)
5. Income Tax Depreciation (Schedule 7, Page 3 of 3)
6. Interest Expense (Schedule 7, Page 3 of 3)
7. Preferred Dividend Credit (if any) (Schedule 7 Page 3 of 3)

8. Income Tax Base

9. Preliminary Income Taxes @ Income Tax Conversion Factor (1)

10. Deduct: Investment Tax Credit Flow Through (Line 4)
10.1 Production Tax Credit (Line 4.1)
11. Preferred Dividend Credit (Line 7)

12. Federal and State Income Taxes

(1) $\dfrac{\text{Composite Tax Rate (2)}}{\text{1 - Composite Tax Rate (2)}}$ = Income Tax Conversion Factor

(2) Composite Federal and State Income Tax Rate as determined in accordance with Schedule 7, Page 2 of 3.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

DETERMINATION OF FEDERAL AND STATE COMPOSITE INCOME TAX RATES

Let: F = Federal Income Tax Rate
M = Minnesota State Income Tax Rate
D = North Dakota State Income Tax Rate
S = South Dakota State Income Tax Rate
W = Wisconsin State Income Tax Rate
MI = Michigan State Single Business Tax Rate
N = Net Income After Net Deductions But Before Income Taxes

NSP Company (Minnesota)

Only Minnesota and Federal Income Taxes:
M = ______________ (N)
F = ______________ (N)
M + F = _______________ (N)

Only North Dakota and Federal Income Taxes:
F = ______________ (N)
D = ______________ (N)
F + D = _______________ (N)

Only South Dakota and Federal Income Taxes:
S + F = _______________ (N)

NSP Company (Minnesota): Combined Minnesota, North Dakota, South Dakota
M + D + S + F = _______________ (N)

NSP Company (Wisconsin):

Wisconsin, Michigan and Federal Income Taxes
W = ______________ (N)
MI = ______________ (N)
F = ______________ (N)
W +MI+ F = _______________ (N)

Notes: 1. Investment Tax Credit, Production Tax Credit, and Surtax Credits are ignored in all formulas.

2. State Income Taxes are deductible from Federal Taxable Income.
Federal Income Tax is deductible from North Dakota Taxable Income.
Federal Income Tax is not deductible from Minnesota or Wisconsin Taxable Income.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 7

DEDUCTIONS FOR COMPUTATION OF FEDERAL AND STATE INCOME TAXES

Investment Tax Credit Flow Through

The Investment Tax Credit Flow Through is recorded in FERC Account 411.4. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production, nuclear fuel, transmission, distribution and general plant as functionalized.

Production Tax Credit

The Production Tax Credit is recorded in FERC Account 409.1. The amounts included for the calculation of income taxes are those amounts attributable to the plant investment related to the production function. Production Tax Credit will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Income Tax Depreciation

Income Tax Depreciation allowable for the calculation of Federal and State income taxes is based upon the plant investment related to production, nuclear fuel, transmission, distribution and general plant as functionalized. Income Tax Depreciation will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Interest Expense

Interest costs associated with debt recorded in FERC Accounts 221-224 is used to calculate the embedded cost of debt. The embedded cost of debt times the debt ratio as determined on Exhibit V, Schedule 6, applied to the rate base determines the interest expense deduction for income taxes.

Preferred Dividend Credit

A Preferred Dividend Credit (if any) is allowed on certain preferred stock issues in accordance with Section 247 of the Internal Revenue Code. This credit is reflected in the calculation of income taxes.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 8**

DEPRECIATION AND AMORTIZATION EXPENSE

Depreciation expense and depreciation expense for asset retirement costs are recorded in FERC Account 403 and 403.1, respectively by the plant functional classifications. Depreciation rates used to calculate the depreciation expense for the original cost of plant as classified by functions for this Agreement are shown on Exhibit IX - Specification of Depreciation Rates.

Amortization expense included to determine the charges among the Parties are recorded in FERC Accounts 404, 405, 406, and 407. Depreciation and amortization expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall include the following annual amounts related to the theoretical reserve surplus. Theoretical Reserve Surplus Amortization Expense included in determining the charges among the Parties is recorded in FERC Account 407.4 (creation of Regulatory Asset) and FERC Account 407.3 (amortization of Regulatory Asset) by the plant functional classifications.

In the NSP (Minn) 2013 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-12-961, order dated September 3, 2013), the MPUC approved the amortization of the theoretical reserve surplus over a period other than the average remaining life. The NSP (Wis) portion of the theoretical reserve surplus is $26,674,271.

In the NSP (Minn) 2014 test year Minnesota retail electric rate case (MPUC Docket No. E002/GR-13-868, order dated May 8, 2015), the MPUC approved the accelerated amortization of the theoretical reserve surplus. Specifically, the MPUC approved the balance of the remaining theoretical reserve surplus for transmission, distribution, intangible and general functions of plant be amortized in a pattern of 50 percent for 2014, 30 percent for 2015, and 20 percent for 2016. Please refer to Exhibit V, Schedule 4.2. As of December 31, 2016, the theoretical reserve surplus was fully amortized.

In the NSP (Minn) 2017 Annual Review of Remaining Lives (MPUC Docket No. E,G002/D-17-147, order dated February 8, 2018), the MPUC approved the amortization rates to unwind the Regulatory Asset created through the amortization of the theoretical reserve surplus, effective January 1, 2017.

The table below shows the annual amortization expense amount beginning in 2013 and continuing through the remaining lives of the associated plant. Consistent with remaining life theory, NSP (Minn) will amortize the regulatory asset through an expense in FERC Account 407.3 and an offsetting credit to expense in FERC Account 403.

Theoretical Reserve Surplus Amortization Expense

Year	Transmission	Distribution	General	Total
2013	($3,330,665)	($2,256)	($1,362)	($3,334,283)
2014	($11,657,328)	($7,898)	($4,768)	($11,669,994)
2015	($6,994,397)	($4,738)	($2,861)	($7,001,996)
2016	($4,662,931)	($3,159)	($1,907)	($4,667,997)
2017	$630,625	$490	$1,857	$632,972
2018	$630,625	$490	$1,857	$632,972
2019	$630,625	$490	$1,857	$632,972
2020	$630,625	$490	$1,857	$632,972
2021	$630,625	$490	$1,857	$632,972
2022	$630,625	$490	$1,615	$632,730
2023	$630,625	$490	$0	$631,115

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.1

THEORETICAL RESERVE SURPLUS AMORTIZATION EXPENSE

Year	Transmission	Distribution	General	Total
2024	$630,625	$490	$0	$631,115
2025	$630,625	$490	$0	$631,115
2026	$630,625	$490	$0	$631,115
2027	$630,625	$490	$0	$631,115
2028	$630,625	$490	$0	$631,115
2029	$630,625	$490	$0	$631,115
2030	$630,625	$490	$0	$631,115
2031	$630,625	$490	$0	$631,115
2032	$630,625	$490	$0	$631,115
2033	$630,625	$490	$0	$631,115
2034	$630,625	$490	$0	$631,115
2035	$630,625	$490	$0	$631,115
2036	$630,625	$490	$0	$631,115
2037	$630,625	$490	$0	$631,115
2038	$630,625	$490	$0	$631,115
2039	$630,625	$490	$0	$631,115
2040	$630,625	$490	$0	$631,115
2041	$630,625	$490	$0	$631,115
2042	$630,625	$490	$0	$631,115
2043	$630,625	$490	$0	$631,115
2044	$630,625	$490	$0	$631,115
2045	$630,625	$490	$0	$631,115
2046	$630,625	$490	$0	$631,115
2047	$630,625	$490	$0	$631,115
2048	$630,625	$490	$0	$631,115
2049	$630,625	$490	$0	$631,115
2050	$630,625	$490	$0	$631,115
2051	$630,625	$490	$0	$631,115
2052	$630,625	$485	$0	$631,110
2053	$557,037	$408	$0	$557,445
2054	$525,623	$0	$0	$525,623
2055	$525,623	$0	$0	$525,623
2056	$445,622	$0	$0	$445,622
2057	$230,462	$0	$0	$230,462
2058	$225,990	$0	$0	$225,990
2059	$225,990	$0	$0	$225,990
2060	$225,990	$0	$0	$225,990
2061	$225,990	$0	$0	$225,990
2062	$225,990	$0	$0	$225,990
2063	$225,990	$0	$0	$225,990
2064	$153,398	$0	$0	$153,398
2065	$123,777	$0	$0	$123,777
2066	$17,670	$0	$0	$17,670
2067	$2,974	$0	$0	$2,974
2068	$2,974	$0	$0	$2,974
2069	$1,712	$0	$0	$1,712

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.2

PRAIRIE ISLAND EXTENDED POWER UPRATE AMORTIZATION REVENUE REQUIREMENT

This Schedule 8.2 explains the Prairie Island Nuclear Plant Extended Power Uprate (PI EPU) amortization expense revenue requirement calculation for purposes of this Agreement.

The PI EPU amortization revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion ($11,996,581) of the total actual PI EPU cancelled project costs ($78,884,915) over the remaining life of the Prairie Island plant as determined by the Minnesota Public Utilities Commission (MPUC) in the NSP (Minn) 2014 test year rate case, Docket No. E002/GR-13-868.

NSP (Wis)'s portion of the total actual PI EPU cancelled project costs is based on the application of the coincident peak demand ratios accepted by the Commission for the Interchange Agreement in Docket No. ER14-1325-000. The annual amortization amount is calculated based on the 18.3-year remaining life of the Prairie Island Plant beginning on January 1, 2016. The annual amortization amount is calculated as follows:

	Total	NSP (Minn.)	NSP (Wis.)
Demand Allocation Between Parties	100.0000%	84.7923%	15.2077%
PI EPU Abandoned Plant Costs	$78,884,915	$66,888,334	$11,996,581
Annual Amortization Expense	$ 4,302,814	$ 3,648,455	$ 654,359

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) shall also include a return on the rate base associated with the unrecovered balance of PI EPU cancelled project costs including Allowance for Funds Used During Construction (AFUDC). The return on rate base shall be calculated as the 13 month average rate base of the PI EPU cancelled project costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) weighted debt-only cost of capital. The cost of capital used to calculate the return on rate base shall include only the cost of debt at the current NSP (Minn) rate and capital structure percentage as determined under Exhibit V, Schedule 6.

NSP (Minn)'s demand related cost of service used in determining billings to NSP (Wis) for the period commencing January 1, 2016, shall include $654,359 per year for purposes of amortizing expenditures on the cancelled PI EPU project. The inclusion of that amount shall continue until NSP (Minn) has recovered from NSP (Wis) its share ($11,996,581) of the total actual PI EPU cancelled project costs including AFUDC. In the last month of the amortization, an amount of less than one-twelfth of the $654,359 may be included in the fixed charges to achieve precise recovery of the PI EPU cancelled project costs.

The PI EPU cancelled project costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2 Unrecovered Plant and Regulatory Study Costs. PI EPU amortization expense is recorded by NSP (Minn) in Account 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

This schedule will be effective beginning January 1, 2016.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.3

MONTICELLO LIFE CYCLE MANAGEMENT / EXTENDED POWER UPRATE PROJECT
RETURN ON RATE BASE ADJUSTMENT

Demand related costs will be reduced by the return on rate base for a portion of the Monticello Life Cycle Management/Extended Power Uprate (Monticello LCM/EPU) Project for purposes of this Agreement. The reduction incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Orders in Docket No. E002/CI-13-754 (Investigation into Xcel Energy's Monticello LCM/EPU Project and Request for Recovery of Cost Overruns) and Docket No. E002/GR-13-868 (Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota), (together the "Monticello LCM/EPU Orders").

The Monticello LCM/EPU Orders approved recovery of the total project cost, but limited recovery of the return on rate base to the original MPUC Certificate of Need application amounts, escalated, including AFUDC, to $415 million. The MPUC Order in Docket No. E002/GR-13-868 issued August 31, 2015, clarified that all (past, present and future) depreciation expense recorded in the accumulated depreciation reserve be allocated on a pro-rated basis between the total project cost that earns a return ($415 million) and the total project cost that does not earn a return (amounts in excess of $415 million).

The adjustment shall be calculated by determining the return on rate base and associated income taxes on the Monticello LCM/EPU Project prorated rate base not allowed a return and applying the NSP (Wis.) demand allocation percent. The Monticello LCM/EPU Project prorated rate base not allowed a return will be determined by applying the percentage of total Monticello LCM/EPU Project costs in excess of $415 million to total Monticello LCM/EPU Project costs to each component of the Total Monticello LCM/EPU Project rate base (plant in service, accumulated provision for depreciation, and accumulated deferred income taxes).

The reduced return on rate base shall continue until the Monticello LCM/EPU Project is fully depreciated, currently expected to be 2030.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 8.4

BENSON POWER TERMINATION AMORTIZATION REVENUE REQUIREMENT

Demand related costs will be adjusted to include an amortization and return on the rate base of the costs incurred by NSP (Minn) to acquire the Benson Power, LLC ("Benson Power") biomass generating plant, terminate the power purchase agreement with Benson Power, and subsequently close and dismantle the Benson Power facility (collectively the "Total Actual Benson Power Termination Costs"). This adjustment incorporates into the Interchange Agreement billings from NSP (Minn.) to NSP (Wis.) the Minnesota Public Utilities Commission (MPUC) Order in Docket No. E002/M-17-530 (Petition to Terminate the PPA with Benson Power, LLC) and the FERC Order in Docket No. EC17-166-000 (approving the NSP (Minn) purchase of the Benson Power, LLC facility).

The Benson Power termination revenue requirement is equal to the current year amortization and calculated return on rate base of NSP (Wis)'s portion of the total actual costs incurred by NSP (Minn) to acquire the Benson Power generating plant, terminate the power purchase agreement with Benson Power, and close and dismantle the Benson Power facility and remediate the site of the Benson Power facility ("Benson Power Termination Costs").

The annual amortization charge to NSP (Wis) will be calculated as follows:

1.		Total Actual Benson Power Termination Costs
2.	Multiply	NSP (Wis)'s Share of the 2018 NSP System Budget Energy Ratio
3.	Equals	NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
4.		NSP (Wis)'s Portion of the Total Actual Benson Power Termination Costs
5.	Divide	Period of Time between Termination Date and Contract Expiration (9/10/2028)
6.	Equals	Annual Amortization Charge to NSP (Wis)

A return on rate base will be calculated on the unrecovered balance of Benson Power Termination Costs. The return on rate base will be calculated as the 13 month average rate base of the actual incurred Benson Power Termination Costs, less accumulated amortization, less accumulated deferred income taxes multiplied by the NSP (Minn) cost of capital. The cost of capital shall be based on the NSP (Minn) currently authorized State of Minnesota retail electric return on equity and the cost of debt and capital structure percentage as determined under Exhibit V, Schedule 6, Return on Rate Base.

The Benson Power Termination Costs included in determining the charges among the Parties are recorded by NSP (Minn) in Account 182.2, Unrecovered Plant and Regulatory Study Costs, and Account 182.3, Other Regulatory Assets. The Benson Power Termination amortization expense is recorded by NSP (Minn) in Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, and Account 557, Other Expenses.

This schedule will be effective on the month and day NSPM acquires the Benson Power facility and terminates the power purchase agreement with Benson Power, and will continue through the contract expiration date of September 10, 2028.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 9

PROVISION FOR DEFERRED INCOME TAXES

The Provision for Deferred Income Taxes is recorded in FERC Accounts 410.1 and 411.1, amounts debited and amounts credited, respectively. The Companies have segregated the deferred income taxes by functional classification in the same detail as the original cost of plant investment. Provision for Deferred Income Taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 10

PROPERTY TAXES

The Property Tax expense or taxes in lieu of property taxes are recorded in FERC Account 408.1. Each Company has segregated its taxes by functional classification in the same detail as the original cost of plant investment. The Property Tax expense or taxes in lieu of property taxes will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 11

INSURANCE EXPENSE

The Insurance Expense is recorded in FERC Accounts 924 and 925. Insurance expense included is related to the production plant and transmission and distribution substations in the same manner as the original cost of the plant investment for these facilities. Insurance Expense will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12

FIXED PRODUCTION OPERATING AND MAINTENANCE EXPENSE

Production Operating and Maintenance Expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be demand related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X. Fixed Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 12.1

FIXED REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSE

Regional Market Operating and Maintenance Expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be demand related as billed.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 13

NET PURCHASED POWER DEMAND COSTS

Purchased Power Demand Costs as billed are recorded in FERC Account 555 - Purchased Power. Firm Power Sales Demand Charges made to eligible non-associated entities are recorded in FERC Account 447 - Revenue from Sales for Resale. The net amount of these demand charges and credits is included as the Net Purchased Power Demand costs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

**Exhibit V
Schedule 14**

PRODUCTION SYSTEM CONTROL AND LOAD DISPATCHING EXPENSE

Production System Control and Load Dispatching expense is recorded in FERC Account 556. 100% of these power supply expenses is included to determine the charges under the Agreement in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V Schedule 15

TRANSMISSION OPERATION AND MAINTENANCE EXPENSE

Transmission Operation and Maintenance expenses are recorded in FERC Accounts 560 through 573. 100% of these expenses is considered fixed or demand related.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 16

CREDITS FOR PRODUCTION-RELATED SERVICES

Revenue for Production-Related Services is recorded in FERC Accounts 454 - Rent From Electric Property and 456 - Other Operating Revenue. These Revenues are credited to production operating and maintenance expenses.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit V
Schedule 17

CREDITS FOR TRANSMISSION RELATED SERVICES

Revenue from Transmission Related Service is recorded in FERC Accounts 454 – Rent from Electric Property, 456 - Other Electric Revenues, and 456.1 – Revenues From Transmission of Electricity of Others. These revenues are credited to transmission operating and maintenance expenses.

Provision for rate refunds recorded in FERC Account 449.1 include transmission related amounts being collected subject to refund which are estimated to be required to be refunded.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VI**

FORMULA TYPE PROCEDURES FOR DEVELOPMENT OF ENERGY RELATED COSTS

The energy-related costs used in Exhibit IV shall be those developed on Line 5 of this exhibit.

	NSP (Minn)	NSP(Wis)
1.	Fuel Expenses (Schedule 1)	
2.	Variable Production and Regional Market Operating, and Maintenance Expense (Schedule 2 and 2.1)	
3.	Net Purchased Power Energy Costs (Schedule 3)	
4.	Carrying Cost on Fuel Stocks	
4.1	Carrying Cost on Energy-Related Deferred Nuclear Refueling Outage Costs	
5.	Total Energy Related Costs (Total lines 1 through 4.1)	

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 1

FUEL EXPENSES

Fuel Expenses are recorded in FERC Accounts 501, 518 and 547. 100% of fuel expenses is included as a variable expense in accordance with the FERC Classification of Production Expenses - Exhibit X.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2

VARIABLE PRODUCTION OPERATING AND MAINTENANCE EXPENSES

Production Operating and Maintenance expenses are recorded in FERC Accounts 500 through 554 and 557. The expenses recorded in these accounts are determined to be energy related in accordance with the FERC Demand and Energy Classification of Production Expenses - Exhibit X. Variable Production Operating and Maintenance Expenses will exclude amounts related to assets that are direct assigned to participating customers for ratemaking purposes under state retail tariffs.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 2.1

VARIABLE REGIONAL MARKET OPERATING AND MAINTENANCE EXPENSES

Regional Market Operating and Maintenance expenses are recorded in FERC Accounts 575 through 576. The expenses recorded in these accounts are determined to be energy related as billed.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VI
Schedule 3

NET PURCHASED POWER ENERGY COSTS

Purchased Power Energy Costs as billed are recorded in FERC Account 555 - Purchased Power and FERC Account 555.1 – Power Purchased for Energy Storage Operations. Firm power energy sales are recorded in Account 447 - Revenue from Sales for Resale. The net amount of these energy charges and credits is included as the Net Purchased Power Energy costs. Purchased Power Energy Costs shall be adjusted to exclude amounts related to energy requirements fulfilled by energy resources required by certain state energy policies, statutes, or state retail tariffs that are direct assigned to participating customers for ratemaking purposes.[1/]

[1/] Including, but not limited to, the NSP (Minn) Renewable*Connect program. For the community solar garden programs and other programs similar in nature, the actual cost of such energy shall be excluded from FERC Account 555 and substituted with the market cost of such generation. The market cost shall be calculated using the hourly day-ahead locational marginal price ("LMP") from the MISO energy market. Costs incurred for community solar garden generation power above the amount calculated using the hourly day-ahead LMP will be direct assigned to NSP (Minn) or NSP (Wis) and the applicable state jurisdiction approving the solar garden.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit VII**

SPECIFICATION OF RATE OF RETURN ON COMMON EQUITY

The rate of return on common equity to determine the overall cost of capital as developed in accordance with Exhibit V, Schedule 6, is 10.40%.

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit VIII

SPECIFICATION OF AVERAGE MONTHLY COINCIDENTAL PEAK DEMANDS

Calendar Year 2024 Contract Year
Monthly Coincidental Peak Demands (KW)

		NSP (Minn)	NSP (Wis)	Total System
2022	January	5,352	1,071	6,423
	February	5,194	1,016	6,210
	March	4,798	965	5,763
	April	4,628	938	5,566
	May	5,607	1,125	6,732
	June	7,883	1,362	9,245
	July	7,686	1,323	9,008
	August	7,446	1,318	8,765
	September	6,857	1,232	8,089
	October	4,661	936	5,597
	November	4,748	1,062	5,810
	December	5,325	1,128	6,453
	Total	70,185	13,476	83,661
2023	January	5,079	1,092	6,171
	February	5,056	1,077	6,133
	March	4,671	1,001	5,672
	April	5,115	941	6,056
	May	6,389	1,152	7,541
	June	6,796	1,205	8,001
	July	7,219	1,264	8,483
	August	7,227	1,258	8,485
	September	6,292	1,113	7,405
	October	4,703	919	5,622
	November	4,771	1,070	5,841
	December	5,297	1,125	6,423
	Total	68,615	13,216	81,831
2024	January	5,357	1,122	6,479
	February	4,968	1,068	6,036
	March	4,795	1,055	5,850
	April	4,383	840	5,223
	May	5,648	1,072	6,720
	June	6,922	1,341	8,263
	July	7,250	1,280	8,530
	August	7,275	1,256	8,531
	September	6,238	1,101	7,339
	October	4,670	904	5,574

November	4,735	1,063	5,798
December	5,263	1,142	6,405
Total	67,505	13,244	80,749

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2024 CONTRACT YEAR

The annual composite depreciation rates for production are calculated based on forecasted depreciation expense accruals and average plant balances. The forecasted depreciation expense is calculated based on approved remaining life depreciation lives and rates certified by the respective state Commissions for NSP (Minn) and NSP (Wis). Rates for transmission, distribution, and general functions are the approved rates for each plant account. NSP (Minn)'s rates are a blended calculation of the approved rates in Minnesota, North Dakota, and South Dakota. NSP (Wis)'s approved rates are the same for both the Wisconsin and Michigan jurisdictions. Even though individual depreciation lives may not have changed from the previous year, these are composite rates and a change in plant balances could cause a change in the rate by FERC Account.

NSP (Minn)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	5.09%
E312	STEAM	Boiler Plant Equipment	4.70%
E314	STEAM	Turbogenerator Units	4.55%
E315	STEAM	Accessory Electric Equipment	4.04%
E316	STEAM	Miscellaneous Power Plant Equipment	4.43%
E302	NUCLEAR	Franchises & Consents	3.98%
E321	NUCLEAR	Structures and Improvements	3.73%
E322	NUCLEAR	Reactor Plant Equipment	3.57%
E323	NUCLEAR	Turbogenerator Units	2.98%
E324	NUCLEAR	Accessory Electric Equipment	3.63%
E325	NUCLEAR	Miscellaneous Power Plant Equipment	3.96%
E302	HYDRO	Franchises & Consents	3.74%
E331	HYDRO	Structures and Improvements	7.15%
E332	HYDRO	Reservoirs, Dams and Waterways	5.65%
E333	HYDRO	Water Wheels, Turbines & Generators	6.11%
E334	HYDRO	Accessory Electric Equipment	6.29%
E335	HYDRO	Miscellaneous Power Plant Equipment	4.03%
E336	HYDRO	Roads, Railroads and Bridges	2.62%
E340.1	OTHER	Wind Rights	2.42%
E341	OTHER	Structures and Improvements	3.07%
E342	OTHER	Fuel Holders, Producers & Accessories	4.53%
E343	OTHER	Prime Movers	3.90%
E344	OTHER	Generators	3.92%
E345	OTHER	Accessory Electric Equipment	2.90%
E346	OTHER	Miscellaneous Power Plant Equipment	4.70%
E348	OTHER	Energy Storage Equipment – Production	0.00%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

TRANSMISSION		
E351	Energy Storage Equipment – Transmission	0.00%
E352	Structures and Improvements	1.74%
*E352	Structures and Improvements-Prod.	1.74%
E353	Station Equipment	2.15%
*E353	Station Equipment-Prod.	2.15%
E354	Towers and Fixtures	2.04%
*E354	Towers and Fixtures-Prod.	2.04%
E355	Poles and Fixtures	2.56%
*E355	Poles and Fixtures-Prod.	2.56%
E356	Overhead Conductors & Devices	2.09%
*E356	Overhead Conductors & Devices-Prod.	2.09%
E357	Underground Conduit	1.42%
E358	Underground Conductors & Devices	2.11%
DISTRIBUTION		
E361	Structures and Improvements	2.26%
*E361	Structures and Improvements-Prod.	2.29%
E362	Station Equipment	2.61%
*E362	Station Equipment-Prod.	2.65%
E363	Energy Storage Equipment – Distribution	0.00%
E364	Poles, Towers and Fixtures	5.38%
E365	Overhead Conductors and Devices	3.54%
E366	Underground Conduit	1.99%
E367	Underground Conductor and Devices	2.41%
E368	Line Transformers	3.44%
E368	Line Capacitors	4.53%
E369	Overhead Services	5.00%
E369	Underground Services	2.58%
E370	Meters	6.89%
E370.2	AGIS Meters	5.02%
E370.3	Electric Vehicle Chargers	10.33%
E373	Street Lighting and Signal Systems	5.24%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

GENERAL - ELECTRIC

E302	Franchises & Consents	4.91%
E303	Intangible Plant – 5 Year	20.48%
E303	Intangible Plant – 10 Year	10.06%
E390	Structures and Improvements	1.89%
E391	Office Furniture and Equipment	4.90%
E391	Network Equipment	16.89%
E392	Transportation Equipment – Auto	9.35%
E392	Transportation Equipment – Light Truck	8.67%
E392	Transportation Equipment – Trailers	6.91%
E392	Transportation Equipment – Heavy Trucks	7.32%
E393	Stores Equipment	4.86%
E394	Tools, Shop and Garage Equipment	6.58%
E395	Laboratory Equipment	9.77%
E396	Power Operated Equipment	6.27%
E397	Communication Equipment – General	10.03%
E397	Communication Equipment – Two Way	9.94%
E397	Communication Equipment – AMR	6.37%
*E397	Communication Equipment – EMS	6.58%
E397	Communication Equipment – Smart Grid	5.35%
E398	Miscellaneous Equipment	6.60%

The Nuclear Decommissioning annual accrual is an approved amount which is recovered from customers to fund the decommissioning of the Monticello and Prairie Island nuclear generating facilities.

Jurisdiction	2024 Approved Accrual	Docket No./Case No.
Minnesota Retail	$21,571,110	E002/M-20-855
North Dakota Retail	$2,250,002	PU-20-441
South Dakota Retail	$2,769,552	EL22-017
Wisconsin Retail	$9,300,587	E002/M-20-855 4220-UR-126

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit IX**

SPECIFICATION OF COMPOSITE DEPRECIATION RATES 2024 CONTRACT YEAR

NSP (Wis)

FERC ACCOUNT		DESCRIPTION	ANNUAL DEPRECIATION RATE
PRODUCTION			
E311	STEAM	Structures and Improvements	6.17%
E312	STEAM	Boiler Plant Equipment	5.31%
E314	STEAM	Turbogenerator Units	4.40%
E315	STEAM	Accessory Electric Equipment	6.92%
E316	STEAM	Miscellaneous Power Plant Equipment	4.27%
E302	HYDRO	Franchises & Consents	1.46%
E331	HYDRO	Structures and Improvements	3.57%
E332	HYDRO	Reservoirs, Dams and Waterways	4.20%
E333	HYDRO	Water Wheels, Turbines & Generators	4.85%
E334	HYDRO	Accessory Electric Equipment	5.58%
E335	HYDRO	Miscellaneous Power Plant Equipment	5.04%
E341	OTHER	Structures and Improvements	5.05%
E342	OTHER	Fuel Holders, Producers & Accessories	4.24%
E343	OTHER	Prime Movers	5.06%
E344	OTHER	Generators	5.57%
E345	OTHER	Accessory Electric Equipment	5.73%
E346	OTHER	Miscellaneous Power Plant Equipment	2.93%
E348	OTHER	Energy Storage Equipment – Production	0.00%
TRANSMISSION			
E351		Energy Storage Equipment – Transmission	0.00%
E352		Structures and Improvements	2.09%
*E352		Structures and Improvements-Prod.	2.09%
E353		Station Equipment	2.80%
*E353		Station Equipment-Prod.	2.80%
E354		Towers and Fixtures	1.80%
E355		Poles and Fixtures	3.28%
E356		Overhead Conductors & Devices	2.80%
E357		Underground Conduit	1.76%
E358		Underground Conductors & Devices	2.77%
E359		Roads and Trails	1.75%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit IX

DISTRIBUTION

E361	Structures and Improvements	2.03%
*E361	Structures and Improvements – Prod.	2.03%
E362	Station Equipment	2.51%
*362	Station Equipment – Prod.	2.51%
E363	Energy Storage Equipment – Distribution	10.00%
E364	Poles, Towers and Fixtures	5.26%
E365	Overhead Conductors and Devices	3.51%
E366	Underground Conduit	1.62%
E367	Underground Conductor and Devices	2.24%
E368	Line Transformers	2.28%
E368	Line Capacitors	2.66%
E369	Overhead Services	3.61%
E369	Underground Services	2.73%
E370	Meters	4.54%
E370.1	Meters – Old	0.00%
E370.2	AGIS Meters	5.00%
E370.6	Meters – AMR	4.84%
E371	Customer Installations	0.00%
E371.4	Installations on Customer's Premises-EV	10.00%
E371.5	Customer Prem-REMS	3.33%
E373	Street Lighting and Signal Systems	5.72%

GENERAL ELECTRIC

E302	Franchises & Consents	5.00%
E303	Intangible Plant – 3 Year	33.33%
E303	Intangible Plant – 5 Year	25.98%
E303	Intangible Plant – 7 Year	14.29%
E303	Intangible Plant – 10 Year	10.00%
E303	Intangible Plant – 15 Year	6.76%
E390	Structures and Improvements	2.17%
E391	Office Furniture and Equipment	4.57%
E391	Network Equipment	18.83%
E392	Transportation Equipment – Auto	12.67%
E392	Transportation Equipment – Light Truck	12.38%
E392	Transportation Equipment – Trailers	5.62%
E392	Transportation Equipment – Heavy Truck	8.21%
E393	Stores Equipment	4.45%
E394	Tools, Shop and Garage Equipment	4.80%
E395	Laboratory Equipment	3.45%
E396	Power Operated Equipment	5.96%
E397	Communication Equipment – AES/AMR	6.11%
*E397	Communication Equipment – EMS	6.11%
E398	Miscellaneous Equipment	4.48%

Agreement to Coordinate Planning and Operations and Interchange Power and Energy **Exhibit X**

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Energy
	Steam Power Generation Operation		
500	Operation Supervision and Engineering	X	
501	Fuel		X
502	Steam Expenses	X	
503	Steam from other sources		X
504	Steam transferred - CR		X
505	Electric Expenses	X	
506	Miscellaneous steam power expenses	X	
507	Rents	X	
509	Allowances		X
	Maintenance		
510	Supervision and engineering		X
511	Structures	X	
512	Boiler plant		X
513	Electric plant		X
514	Miscellaneous steam plant	X	
	Nuclear Power Generation Operation		
517	Operation supervision and engineering	X	
518	Fuel		X
519	Coolants and water	X	
520	Steam expenses	X	
523	Electric expenses	X	
524	Miscellaneous nuclear power expenses	X	
525	Rents	X	
	Maintenance		
528	Supervision and engineering		X
529	Structures	X	
530	Reactor plant equipment		X
531	Electric plant		X
532	Miscellaneous nuclear plant		

X

Agreement to Coordinate Planning and Operations and Interchange Power and Energy

Exhibit X

SPECIFICATIONS OF DEMAND AND ENERGY
CLASSIFICATION OF PRODUCTION EXPENSES

Uniform System of Accounts Account No.	Description	Classification Demand	Energy
	Hydraulic Power Generation Operation		
535	Operation supervision and engineering	X	
536	Water for power	X	
537	Hydraulic expenses	X	
538	Electric expenses	X	
539	Miscellaneous hydraulic power expenses	X	
540	Rents	X	
	Maintenance		
541	Supervision and engineering	X	
542	Structures	X	
543	Reservoirs, dams and waterways	X	
544	Electric plant		X
545	Miscellaneous hydraulic plant	X	
	Other Power Generation Operation		
546	Operation Supervision and Engineering	X	
547	Fuel		X
548	Generation expenses	X	
548.1	Operation of energy storage equipment	X	
549	Miscellaneous other power generation	X	
550	Rents	X	
	Maintenance		
551	Supervision and engineering	X	
552	Structures	X	
553	Generating and electric equipment	X	
553.1	Maintenance of energy storage equipment	X	
554	Miscellaneous other power generation plant	X	
	Other Power Supply Expenses		
555	Purchased power		As Billed
555.1	Power purchased for storage operations		As Billed
556	System control and load dispatching	X	
557	Other expenses		As Billed

Document Content(s)