In the Matter of the Application of Minnesota Power for
Authority to Increase Electric Service Rates in Minnesota
Docket No. E015/GR-21-335

VOLUME 1 INDEX

Notice of Change in Rates – Interim Petition

INDEX - VOLUME 1

Notice of Change in Rates – Interim Petition *Continued*

STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Pursuant to the Minnesota Public Utilities Commission's Revised Procedures for Handling Trade Secret and Privileged Data in furtherance of Minn. Stat. § 13.37 and Minn. Rule 7829.0500, Minnesota Power has designated portions of designated exhibits attached to the Application for Authority to Increase Rates for Electric Utility Service in Minnesota ("Application") as Trade Secret.

The Application consists of Minnesota Power's interim and general rate case filings, which contain confidential financial, personnel, contractual, and energy procurement information that is materially sensitive and commercially valuable to Minnesota Power. Minnesota Power follows strict internal procedures to maintain the secrecy of all of this information in order to capitalize on the economic value of the information. As a result of public availability, Minnesota Power and its customers would suffer severe competitive implications, including a detrimental effect on energy costs paid by Minnesota Power's customers.

Minnesota Power believes that this statement and the attached Index of Non-Public Information Contained in Filing provide the justification as to why the information excised from the Application should remain a trade secret under Minn. Stat. § 13.37. The information contained in this schedule constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). The attached Index of Non-Public Information Contained in Filing summarizes the portions of the Application that have been designated as non-public and/or trade secret and the justification for that designation. Minnesota Power respectfully requests the opportunity to provide additional justification in the event of a challenge to the trade secret designation provided herein.

Index of Non-Public/Trade Secret Information Contained in Filing

<table>
<tr><th>Item/Location</th><th>Justification</th></tr>
<tr><td colspan="2">Volume 2, Direct Testimony and Supporting Schedules</td></tr>
<tr><td>Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Cutshall), Direct Schedules 1 through 5 – Moody’s Rating Methodology on Regulated Electric and Gas Utilities. (June 23, 2017), Moody’s Credit Opinion on ALLETE, Inc. (Apr. 27, 2021), Moody’s Issuer Comment on ALLETE, Inc. (Feb. 8, 2018), Moody’s Credit Opinion on ALLETE, Inc. (Feb. 22, 2018), Moody’s Rating Action on ALLETE, Inc. (Mar. 26, 2019)</td><td>Nature of the Material: Subscription-based credit opinions prepared by a third party.

Author: Moody’s Investors Service

General Import: These documents represent credit rating information for ALLETE, Inc. and other financial information as generated by a third party, and which are received through a paid subscription. The data derives value from not being readily ascertainable by the public, and therefore is maintained as a trade secret.

Dates Prepared: June 23, 2017, April 27, 2021, February 8, 2018, February 22, 2018, and March 26, 2019.</td></tr>
<tr><td>Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Cutshall), Direct Schedules 6 through 8 – S&P’s Key Credit Factors for the Regulated Utilities Industry (Nov. 19, 2013), S&P’s Research Update on ALLETE, Inc. (Feb. 6, 2018), S&P’s Research Update on ALLETE, Inc. (Apr. 22, 2020)</td><td>Nature of the Material: Subscription-based credit ratings prepared by a third party.

Author: S&P Global

General Import: These documents represent credit rating information for ALLETE, Inc. and other financial information as generated by a third party, and which are received through a paid subscription. The data derives value from not being readily ascertainable by the public, and therefore is maintained as a trade secret.

Date Prepared: November 19, 2013, February 6, 2018, and April 22, 2020</td></tr>
</table>

Item/Location	Justification
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Cutshall), Direct Schedule 12 – EEI Member Companies, Per Companys' 2020 Annual Reports, Expected Return on Plan Assets	Nature of the Material: Utility retirement plan data in the form of survey results gathered and prepared by a third party. Author: Edison Electric Institute ("EEI") General Import: These documents represent the results of an EEI survey of member utilities' retirement plan components and associated cost recovery. EEI makes this material available to members, including Minnesota Power, by request, but prepares this document independently, maintains this list as proprietary and confidential, and does not share it with the general public. The data derives value for EEI, participants in the survey, and EEI members from not being readily ascertainable by the public, and therefore is maintained as a trade secret. Date Prepared: 2020-2021
Volume 2, Direct Testimony and Supporting Schedules, Direct Testimony and Schedules of Frank L. Frederickson, Section IV.D, customer load data.	The information labeled as trade secret herein includes contractually-negotiated pricing information and is trade secret information as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other parties who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as trade secret.

Item/Location	**Justification**
Volume 2, Direct Testimony and Supporting Schedules, Direct Testimony and Schedules of Benjamin S. Levine, Section II.B, customer sales data	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit __ (Pierce), Direct Schedule 1– Asset-based loss of load wholesale sales from 2016 to 2020, 2021 projected year, and 2022 test year	The information labeled as trade secret herein includes contractually-negotiated pricing information and is trade secret information as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other parties who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as trade secret.

Item/Location	Justification
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit ___ (Krollman), Schedule 2, Excerpt from the 2021 Willis Towers Watson Energy Services BenVal Study	Nature of the Material: Third-party-prepared employer benefit value data Author: Willis Towers Watson General Import: The information provides comparative economic data, was purchased from third party Willis Towers Watson, and derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use. Date Prepared: 2021
Volume 2, Direct Testimony and Supporting Schedules, MP Exhibit ___ (Turner), Schedule 2, Revenue Credits – Test Year 2022 Unadjusted	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

Item/Location	Justification
Volume 3, Required Filing Schedules	
Volume 3, Required Filing Schedules, Direct Schedule E-2, Rate Design, Sales, and Revenue – Monthly	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 3, Required Filing Schedules, Schedule H – 5A, Ten Highest Paid Officers and Employees' Compensation	Schedule H– 5A includes compensation information for the highest paid employees of the Company. Minn. Stat. § 216B.16, subdivision 17(c) allows for the salary of one or more of the ten highest paid officers and employees of Minnesota Power, other than the five highest paid, to be treated as private data on individuals. It also derives independent economic value from not being generally known to, and not being readily ascertainably by proper means by, other persons who can obtain economic value from its disclosure or use.

Item/Location	Justification
Volume 3, Required Filing Schedules, Direct Schedule I-1, Calculation of Conservation Cost Recovery Charge	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 4, Workpapers	
Volume 4, Workpapers, ADJ-IS-22, CCRC Credit for Large Light & Power CIP Opt-Out Customers	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

Item/Location	Justification
Volume 4, Workpapers, ADJ-IS-27, DR Product A Reassign	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 4, Workpapers, ADJ-IS-28, Large Power Demand Response	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

Item/Location	Justification
Volume 4, Workpapers, AF-4, 2022 Jurisdictional & Class Customer Allocation	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 4, Workpapers, AF-5, 2021 Jurisdictional & Class Customer Allocation	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

Item/Location	Justification
Volume 4, Workpapers, AF-6, 2020 Jurisdictional & Class Customer Allocation	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 4, Workpapers, COC-2, S&P Global Market Intelligence, Report (Nov. 12, 2019), S&P Global State Adjustment Clauses (Aug. 20, 2021), S&P Global State Alternative Regulation (Aug. 20, 2021).	Nature of the Material: Subscription-based market reports prepared by a third party. Author: S&P Global General Import: The information herein designated as trade secret is financial information purchased from a third party and has been designated as non-public in its entirety because it contains information the Company considers to be trade secret as defined by Minn. Stat. § 13.37, subd. 1(b). The information derives independent economic value from not being generally known to, or readily ascertainable by proper means by, others who could obtain economic advantage from its disclosure or use. Date Prepared: November 12, 2019, August 20, 2021

Item/Location	Justification
Volume 4, Workpapers, OS-2, Lead Lag Study	The information designated as trade secret herein is financial information and is designated as such because this information is not generally known to and not readily ascertainable by investors and competitors of the Company who could obtain economic value from its disclosure. Thus, this information is trade secret information as defined by Minn. Stat. § 13.37, subd. 1(b).
Volume 4, Workpapers, OS-3, Minnesota Power's 2021 Annual Electric Utility Forecast Report	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.
Volume 4, Workpapers, IR-2, Sales Forecast, Revenue, and Rate Design Data	The information contained herein includes customer data and is designated as trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). Specific customer data (including the name, address, or related usage) consists of "private data on individuals" and "confidential customer data" as recognized under the Minnesota Data Practices Act. As such, any unique information that can identify an individual customer is maintained by the Company as not public data and protected from public disclosure.

In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota
Docket No. E015/GR-21-335

Statement on Rounding

Due to rounding, numbers on schedules presented in this Application may not add up precisely to the totals indicated and percentages may not precisely reflect the absolute figures for the same reason. The cost of service study, on which many of these supporting schedules are based, is calculated using factors which go out to additional decimal points beyond those listed in the schedules. For display purposes, the schedules are rounded to the nearest whole dollar and subtotals and subsequent totals in the cost of service study may be based on actual values. This may result in occasional minor differences between the subtotals and totals on the cost of service study and those on supporting schedules.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E015/GR-21-335

SUMMARY OF FILING

On November 1, 2021, Minnesota Power filed with the Minnesota Public Utilities Commission ("Commission") an Application to Increase Rates for Electric Utility Service in Minnesota ("Application"). Pursuant to Minn. Stat. § 216B.16, subd. 1, Minnesota Power requests a rate increase of $108.3 million, or 17.58 percent, effective January 1, 2022, without suspension. If the Commission elects to suspend the proposed rate increase under Minn. Stat. § 216B.16, subd. 2, Minnesota Power requests, pursuant to Minn. Stat. § 216B.16, subd. 3, that an interim rate increase of $87.3 million, or 14.23 percent, be effective on January 1, 2022, with final rates becoming effective within ten months of the date of the Application.

The average monthly impact of the proposed rate increase for residential customers with an average usage of 701 kilowatt hours per month will be approximately $15.08 per month or $180.96 annually. If the requested rates are suspended, the interim rates will increase the bill for a typical residential customer with average usage by approximately $11.78 per month or $141.36 annually. The impact on individual customers will be higher or lower depending on each customer's actual electric consumption. Minnesota Power also proposes changes to its rate design.

The proposed rate schedules and a comparison of present and proposed rates are available at https://www.mnpower.com/RateReview or at the Minnesota Department of Commerce, 85 Seventh Place East, Suite 500, St. Paul, Minnesota 55101. This filing is also available through the eDockets link on the website of the Commission at mn.gov/puc, under Docket Number E015/GR-21-335.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E015/GR-21-335

NOTICE OF CHANGE IN RATES

A. Introduction

Minnesota Power seeks authority from the Minnesota Public Utilities Commission ("Commission") to increase retail electric rates in Minnesota pursuant to Minn. Stat. § 216B.16 and Minn. R. 7825.3100-7825.4600 and 7829.2400. Minnesota Power requests a rate increase of $108.3 million Minnesota jurisdictional, or approximately 17.58 percent, effective January 1, 2022 without suspension. If the Commission elects to suspend the proposed rate increase under Minn. Stat. § 216B.16, subd. 2, Minnesota Power requests, pursuant to Minn. Stat. § 216B.16, subd. 3, that an interim rate increase of $87.3 million Minnesota jurisdictional, or approximately 14.23 percent, be effective on January 1, 2022, with final rates becoming effective within ten months of the date of this Application for Authority to Increase Rates for Electric Utility Service in Minnesota ("Application"). Minnesota Power also proposes changes to its rate design and terms of service.

This Application includes the following information in accordance with Minnesota Statutes and the Commission's rules:

B. Notice and Proposal Regarding General Rate Change

(Minn. R. 7825.3200(A)(1) and 7825.3500)

1. Name, address and telephone number of utility.

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722-2641

2. Name, address and telephone number of attorneys for the utility.

David R. Moeller Senior Attorney and Director of Regulatory Compliance Minnesota Power 30 West Superior Street Duluth, MN 55802 (218) 723-3963	Elizabeth M. Brama Valerie T. Herring Kodi Jean Verhalen Taft Stettinius & Hollister LLP 2200 IDS Center 80 South 8th Street Minneapolis, MN 55402 (612) 977-8400

3. Date of filing and date modified rates are to be effective.

The date of this filing is November 1, 2021. Pursuant to Minn. Stat. § 216B.16, subd. 1, Minnesota Power respectfully requests that the overall rate increase it proposes become effective January 1, 2022, without suspension. A schedule of rates and tariffs reflecting the revenue increase requested and the proposed rate design described in the attached documents is included with the Application.

If the Commission suspends the proposed rate increase under Minn. Stat. § 216B.16, subd. 2, Minnesota Power respectfully requests, pursuant to Minn. Stat. § 216B.16, subd. 3, that the Commission approve the interim rate increase proposed in the Petition for Interim Rates, which is filed as part of this Application, effective January 1, 2022, with final rates effective within ten months of the date of this Application.

4. Description and purpose of the change in rates requested.

The Application for a change in rates applies to all Minnesota Power retail customers in the State of Minnesota. The overall purpose of the proposed rate change is to produce the additional revenue necessary to meet Minnesota Power's cost of service for the test year ending December 31, 2022. This filing complies with the provisions of Minn. Stat. § 216B.16 and the Commission's rules governing rate changes.

5. Effect of the change in rates.

The effect of the proposed rate increase, which is based on the Company's proposed 2022 test year revenue deficiency, will be an increase in gross revenues for the test year of $108.3 million, or an approximate increase of 17.58 percent. The effect of the proposed interim rates is an $87.3 million, or approximately 14.23 percent, overall increase over gross present rate revenues.

6. Signature and title of utility officer authorizing the proposal.

The Application is signed on behalf of Minnesota Power by Patrick L. Cutshall, ALLETE Vice President & Corporate Treasurer.

C. Modified Rates (Minn. R. 7825.3200(A)(2) and 7825.3600)

Included in this Application are rate schedules containing the proposed changed rates and tariffs. General rate schedules and tariffs are included in Volume 3 of this Application and are supported by the Direct Testimony of Ms. Amanda L. Turner , Costing and Pricing Analyst II, and Ms. Leah N. Peterson, Supervisor of Customer Business Analytics.

D. Expert Opinions and Supporting Documents (Minn. R. 7825.3200(A)(3) and 7825.3700)

The statements of fact, expert opinions, and substantiating documents and exhibits supporting Minnesota Power's proposed change in rates accompany this Application. Pursuant to Minn. R. 7825.3700, Patrick L. Cutshall, ALLETE Vice President & Corporate Treasurer, provides Direct Testimony as Minnesota Power's designated official in support of the Application. A list of Minnesota Power's other witnesses is provided in the Rate Case Overview Direct Testimony of Company witness Ms. Jennifer J. Cady.

E. Information Requirements (Minn. R. 7825.3200(A)(4) and 7825.3800 to 7825.4400)

Included in this Application in Volume 2 are the Direct Testimonies of Minnesota Power's witnesses. Volumes 1 and 3 contain the Company's interim and proposed general rate tariffs and Volume 3 contains Minnesota Power's Information Requirements. These volumes, along with Volume 4, Workpapers, represent Minnesota Power's supporting documentation and contain the information in support of the general rate increase required by Minn. R. 7825.3800 through Minn. R. 7825.4400.

Data are provided for the 2020 most recent fiscal year and the 2021 projected year. The proposed test year is the calendar year ending December 31, 2022. Minn. Rule 7825.3100, Subp. 10 defines "Most recent fiscal year" as "the utility's prior fiscal year unless notice of a change in rates is filed with the commission within the last three months of the current fiscal year <u>and</u> at least nine months of historical data is available for presentation of current fiscal year financial information, in which case the most recent fiscal year is deemed to be the current year." (emphasis added). As discussed in the Direct Testimony of Ms. Amanda Turner, ALLETE's 2021 Third Quarter financial results will be released on November 4, 2021, which is after the date of this filing. Therefore, 2020, the prior fiscal year, is the most recent fiscal year for which data is available as of the date of filing. Treatment of 2020 as the "most recent fiscal year" is consistent with both the plain language of Minn. R. 7825.3100, Subp. 10, and Minnesota Power's most recent rate case filings in Docket Nos. E015/GR-19-442, E015/GR-16-664, and E015/GR-09-1151. In the event the Commission concludes the Company requires a variance to treat 2020 as its most recent fiscal year, Minnesota Power meets each of the requirements for the Commission to grant a variance under Minn. R. 7829.3200. In particular: (1) enforcement of the rule would impose an excessive burden upon the Company as the necessary data for 2021 is not available as of the date of this filing; (2) granting the variance would not adversely affect the public interest, because Minnesota Power has used this approach in the past and it has result in just and reasonable rates; and (3) granting a variance would not conflict with standards imposed by law.

F. <u>Methods and Procedures for Refunding (Minn. R. 7825.3200(A)(5) and 7825.3300)</u>

This Application is accompanied by an "Agreement and Undertaking" signed and verified by Patrick L. Cutshall, ALLETE Vice President & Corporate Treasurer, which commits Minnesota Power to make any refunds ordered by the Commission.

G. <u>Notice to Municipalities and Counties (Minn. Stat. § 216B.16, subd. 1 and Minn. R. 7829.2400, Subp. 3)</u>

Pursuant to Minn. Stat. § 216B.16, subd. 1, Minnesota Power proposes to mail the Proposed Notice to Counties and Municipalities included with the Application to all municipalities and counties in Minnesota Power's Minnesota electric service territory. This notice includes a discussion of the proposed interim rates, as well as information regarding the general electric rate case filing. Minnesota Power respectfully requests Commission approval of the notice so it may be mailed in a timely fashion.

H. Customer Notice (Minn. R. 7829.2400, Subp. 3)

Minnesota Power will send a rate change notice to retail customers as a bill insert that explains the proposed general rate increase. If Minnesota Power's requested retail electric rate increase is suspended, Minnesota Power will also explain the impact of its interim rates on customer bills in the same bill insert. Included in this Application is a proposed customer notice of rate increase. Minnesota Power will work with Commission Staff to revise the notice as necessary so that Minnesota Power may insert the notices in the first bill a customer receives containing changed rates.

Minnesota Power will also publish public notice of the rate change in the newspapers of general circulation in all county seats in Minnesota Power's electric service territory. Included in this Application is an example of Minnesota Power's proposed newspaper notice. Minnesota Power will work with Commission Staff to revise the notice as necessary for prompt Commission approval. Minnesota Power will publish the newspaper notice as directed by the Commission.

I. Filings Requiring Determination of Gross Revenue Requirement (Minn. R. 7829.2400)

Pursuant to Minn. R. 7829.2400, Minnesota Power submits the following information in addition to that required by Minn. R. 7825.3100 – 7825.4600.

1. Summary (Minn. R. 7829.2400, Subp. 1)

A summary of the Application is attached to this Notice.

2. Service; Proof of service (Minn. R. 7829.2400, Subp. 2)

Minnesota Power has served copies of the Application on the Minnesota Department of Commerce, Division of Energy Resources, and the Office of the Attorney General – Antitrust and Utilities Division. Minnesota Power will serve a copy of the Summary of Filing on all parties on Minnesota Power's general service list and on the parties to Minnesota Power's last filed rate case proceeding (Docket No. E015/GR-19-442). A certificate of service is attached.

3. Notice to public and governing bodies (Minn. R. 7829.2400, Subp. 3)

See Sections G and H above.

4. Notice of Hearing (Minn. R. 7829.2400, Subp. 7)

Minnesota Power will notify customers of hearings held in connection with this Application as directed by the Commission. Minnesota Power will also publish notice of the hearings in newspapers of general circulation in all county seats in Minnesota Power's electric service area, as directed by the Commission. *See* Section H above.

J. Request for Protection of Non-Public Information

Minnesota Power recognizes and supports the need for transparency in the review of its Application. A limited number of schedules and workpapers in the Application include Non-Public Data according to Minn. Stat. § 13.37, subd. 1(b) and Minn. R. 7829.0500. Minnesota Power has taken reasonable efforts to maintain the secrecy of this Non-Public Data, which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Minnesota Power provides an index of non-public information contained in this filing with its Statement Regarding Justification for Excising Trade Secret Information in Volume 1 of the Application, which summarizes the documents and exhibits that have been designated as non-public and/or trade secret in part or in full and the justification for those designations. Minnesota Power is filing complete Public and Non-Public versions of the portions of this Application that contain trade secret or non-public information.

K. Service List

Pursuant to Minn. R. 7829.0700, Minnesota Power respectfully requests the following persons representing Minnesota Power be placed on the Commission's official service list for this proceeding:

David R. Moeller
Minnesota Power
30 West Superior Street
Duluth, MN 55802
dmoeller@allete.com

Susan Ludwig
Minnesota Power
30 West Superior Street
Duluth, MN 55802
sludwig@mnpower.com

Elizabeth M. Brama
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
ebrama@taftlaw.com

Valerie T. Herring
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
vherring@taftlaw.com

Kodi Jean Verhalen
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
kverhalen@taftlaw.com

L. Conclusion

Minnesota Power respectfully requests consideration and acceptance of its Application and the accompanying Notices to municipalities and counties, customers, and the public.

Dated: November 1, 2021

Respectfully submitted,

Patrick L Cutshall

Patrick L. Cutshall
ALLETE Vice President & Corporate
Treasurer
30 West Superior Street
Duluth, MN 55802
218-722-2625

Subscribed to before me this 1st day
of November, 2021

Susan Romans

Susan Romans, Notary Public

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E015/GR-21-335

NOTICE AND PETITION FOR INTERIM RATES

A. Introduction

Minnesota Power hereby respectfully submits to the Minnesota Public Utilities Commission ("Commission") this Petition for Interim Rates ("Petition") pursuant to Minn. Stat. § 216B.16, subd. 3, the Commission's Statement of Policy on Interim Rates dated April 14, 1982, and relevant Commission rules. Minnesota Power requests that the Commission authorize an interim rate increase of 14.23 percent, effective January 1, 2022, based on the Company's Minnesota jurisdictional interim revenue deficiency of approximately $87.3 million.

B. Information Provided Pursuant to the Commission Statement of Policy on Interim Rates and Relevant Commission Rules

1. Name, address, and telephone number of utility and attorneys (Policy Statement, Item 1, page 2)

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722-2625

David R. Moeller
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723-3963

Elizabeth M. Brama
Valerie T. Herring
Kodi J. Verhalen
Taft, Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
(612) 977-8400

2. Date of filing and date proposed interim rates are requested to become effective (Policy Statement, Item 2, page 2)

The date of the submission of this Petition is November 1, 2021. This Petition is submitted as part of Minnesota Power's Application for a general electric rate increase ("Application") pursuant to Minn. Stat. § 216B.16, subd. 3. Minnesota Power requests that, if the Commission suspends the operation of the general rate schedules that accompany the Application pursuant to Minn. Stat. § 216B.16, subd. 2, that the proposed interim rates be made effective on January 1, 2022. The interim rates will be subject to refund, with interest, pending final Commission determination on the Application.

3. Description and need for interim rates (Policy Statement, Item 3, page 2)

Minnesota Power has filed only three completed rate cases in the last 25 years, the last being the 2016 Rate Case (Docket No. E015/GR-16-664).[1] Since the outcome of the 2016 Rate Case, Minnesota Power has consistently and significantly under recovered revenue due in large part to actual sales levels being below 2017 test year forecast levels and additional subsequent declines. Despite implementing significant cost cuts and seeking all market sale opportunities to offset revenue deficiencies, the Company was unable to earn its authorized return and suffered credit rating downgrades.

At the same time, Minnesota Power has been proactive and creative in maximizing every opportunity to moderate rates for its customers. The Company has met and exceeded conservation goals for a number of years, and has developed new rates and services that enable residential and

[1] Minnesota Power also submitted a general rate case in 2019 Docket No. E015/GR-19-442 ("2019 Rate Case"); however, due to the advent of the COVID-19 pandemic, the Company developed an alternate resolution with intervening parties and withdrew its 2019 rate request prior to completion of the case.

commercial customers to reduce their consumption and overall energy bills. The Company has also developed new products to support larger industrial customers in highly cyclical industries, and brought in major capital projects on time and under budget. Additionally, the Company has been taking proactive measures to protect customers throughout the COVID-19 pandemic, including (as previously noted) withdrawing its 2019 Rate Case. Minnesota Power's creative thinking, including by initiating pandemic relief and recovery projects to support the local economy, working with contracting partners to delay incurring new costs on large and small projects, undertaking land sales with all proceeds returned to customers, and expanding low income programs and eligibility, have moderated customers' bills but also make it vital for the Company to obtain interim and final rate relief in this proceeding.

Overall, Minnesota Power requires interim rates due to changes in revenue and in its overall cost of providing reliable customer service while leading efforts toward decarbonization, as set forth in the testimony of the Company's witnesses in this proceeding. These costs and changes in revenue are currently being incurred and will continue to be incurred throughout the test year and during the ten-month suspension period and beyond. Without interim rate relief, Minnesota Power would be unable to recover its costs of providing electric service to its customers, and would not have a reasonable opportunity to earn its authorized rate of return, which could result in a further credit rating downgrade for ALLETE, Inc. As a result, it is critical that the Company re-establish rates that reflect current revenue and cost structures and support a financially healthy utility.

Volume 1, Direct Schedules A (IR) through F (IR) and Volume 4, Workpapers accompanying this Petition set forth the calculation of the interim revenue deficiency of $87.3 million, which represents a 14.23 percent increase over present rate revenue. Minnesota Power's interim revenue deficiency is determined using the 2022 test year revenue requirements, with the proposed adjustments set forth below consistent with Minnesota Statutes and Rules. Minnesota Power calculated its proposed interim rates consistent with Commission requirements and precedent.

Minnesota Power requests that the proposed interim rate increase be applied to all classes of Minnesota Power's retail electric customers, but not to the following services, consistent with Commission application of interim rates in the Company's prior rate cases: Large Power Incremental Production Services ("IPS"), Economy/Non-firm Service, Replacement Firm Power Service ("RFPS"), and Pool-within-Pool Service. Generally, the price for these services fluctuates with Minnesota Power's hourly incremental energy costs or is otherwise specified in individual customer agreements, and so these revenues are not included in the Large Power class revenue in the cost-of-service studies.

Riders to Base Rates

For purposes of both interim rates and final rates, the Company proposes to incorporate approximately $0.9 million (MN jurisdictional) that is currently being recovered under the Renewable Resources ("RRR") and Transmission Cost Recovery ("TCR") Riders. As detailed in the testimony of Company witness Mr. Stewart J. Shimmin, Ms. Amanda Turner, and Mr. John Armbruster, these small amounts presently included in riders will simply be moved from riders into base rates. In addition, Minnesota Power proposes to move the excess Accumulated Deferred Income Taxes ("Excess ADIT") resulting from the Tax Cuts and Jobs Act ("TCJA") from the Tax Cut Refund Rider to base rates and discontinue the Tax Cut Refund Rider effective with interim rates in this proceeding. For projects and costs that will continue to be recovered in the applicable riders beyond the end of this rate case, Minnesota Power has adjusted those costs out of the test year rate base and income statement to ensure that no double recovery occurs.

Fuel and Purchased Energy

In its November 5, 2019 Order Approving Compliance Filings in the 2003 Fuel Clause Investigation Docket No. E-999/CI-03-802 ("Fuel Clause Docket Order"), the Commission established new procedures for managing Fuel Clause Adjustment processes. Specifically, the Order approved Minnesota Power's proposals to (i) remove, or "zero out" the fuel and purchased energy ("FPE") costs included in the base cost of energy in the Company's next general rate case; (ii) include all such energy costs in a new FPE Charge; (iii) continue to include the FPE Charge under the Resource Adjustment line on customer bills until final rates are implemented; (iv) show the FPE charge as a separate line item on customer bills effective with final rates; and (v) forego filing a separate Base Cost of Energy filing in future general rate cases, including this one. The Commission also required Minnesota Power to demonstrate in its upcoming initial rate case filing that its proposed base rates do not include any amount of FPE costs.

Minnesota Power removed (or "zeroed out") the entire amount of FPE cost included in base energy rates effective on January 1, 2020 with interim rates in the withdrawn 2019 Rate Case.

Upon the withdrawal of the 2019 Rate Case, this FPE cost treatment (FPE costs zeroed out from base energy rates) remained and continues in present rates. The Company's final general base energy rates also includes no FPE costs. This consistent treatment is demonstrated in Volume 3, Direct Schedule E-2, page 77 (showing that the monthly fuel clause factor by customer class for both present rates and general rates are identical). Thus, the entire cost of fuel and purchased energy is currently included in the FPE Charge.

The FPE Charge continues to be combined with the Conservation Program Adjustment ("CPA") in the Resource Adjustment line item on customer bills. Although the Fuel Clause Docket Order allowed Minnesota Power to show the FPE Charge as a separate line on customer bills effective with final rates in the 2019 Rate Case, that rate case was resolved and withdrawn by the Company, and not all issues raised in the initial rate case filing were addressed in the resolution. At this time Minnesota Power has not yet separated the FPE Charge from the Resource Adjustment line. Consistent with the Fuel Clause Docket Order, Minnesota Power proposes to show the FPE Charge as a separate line item on customer bills effective with final rates in this case.

<u>Interim Rate Adjustments from General Rate Request</u>

The costs included in interim rates, including those discussed above, are appropriate for recovery in interim rates because they are "the same in nature and kind as those allowed" by the Commission Order in Minnesota Power's last electric rate proceeding. Minn. Stat. § 216B.16, subd. 3. To further comply with this statute, the Company proposes the following adjustments to the 2022 final revenue requirement that reflect a difference between its final rate request and interim rate request in this proceeding:

- ***Pro Rata ADIT.*** Under Internal Revenue Service ("IRS") normalization requirements, utilities who use forecast test years for determination of rates must calculate average ADIT using a pro rata method for interim rates, but not final rates. Thus the Interim Rate calculation, but not the General Rate calculation, reflects the pro rata ADIT methodology.

- ***Prepaid OPEB Asset.*** As Minnesota Power has not previously received approval to include the other post-employment benefit ("OPEB") accumulated contributions in excess of net periodic benefit cost (or prepaid OPEB asset) in rate base, this asset is not of the same nature and kind as those allowed by the currently-effective Commission Order and are not included in rate base in our interim rate request. The prepaid OPEB asset and associated ADIT have been removed from the Interim Rate calculation.

- ***Prepaid Pension Asset.*** As Minnesota Power has not previously received approval to recover the costs of its accumulated contributions in excess of net periodic benefit cost (or prepaid pension asset), this asset is not of the same nature and kind as those allowed by the currently-effective Commission Order and are not included in rate base in our interim rate request. Consistent with Order Point 7 of the Commission's March 12, 2018 Order in the Company's 2016 Rate Case, Minnesota Power has also removed the ADIT associated with this asset from the Interim Rate calculation.

- ***Economic Development.*** In Minnesota Power's three most recent rate cases (2008, 2009, and 2016), the Commission allowed recovery of 50 percent of Economic Development and Community Relations costs. Consistent with this treatment, the Company has removed 50 percent of its Economic Development and Community Relations costs from the Interim Rate calculation. However, the Company is requesting recovery of 100 percent of its Economic Development and Community Relations in General Rates.

- ***Demand Response ("DR") Product A Reassignment.*** In the Company's previous rate cases, DR Product A revenue was included in the CCOSS in a way that allocated the revenues only to the Large Power customer class. Because customers taking DR Product A benefit all other customers as well, the Company proposes to reassign DR Product A revenues in a way that will allocate to all customers. To achieve this, DR Product A revenues have been reassigned out of Sales by Rate Class revenue and into LP Demand Response revenue. Thus, the proposed treatment for this revenue will perform similarly to a revenue credit. Consistent with treatment in previous rate cases, this adjustment is not reflected in the Interim Rate calculations, but is reflected in the General Rate calculations.

- ***LP Demand Response.*** This adjustment accounts for a reflection of the full year of lower DR Product A and other LP Demand Response with the implementation of Demand Response Product C. This adjustment is not reflected in the Interim Rate calculations, but is reflected in the General Rate calculations.

- ***Rate of Return on Equity.*** Consistent with the requirements of Minn. Stat. § 216B.16, subd. 3(b), the return on equity included in interim rates is 9.25 percent, which is the return on equity ("ROE") approved by the Commission in Minnesota Power's 2016 Rate Case. This amount is reduced from the Company's requested final rate ROE of 10.25 percent.

- ***Secondary Calculations.*** Cash working capital and interest synchronization are secondary calculations that need to be recalculated during the course of the proceeding to reflect changes to operations and maintenance ("O&M") expenses, rate base, and capital structure. The Company's Interim Rate schedules reflect the appropriate calculations for determination of the interim revenue requirement.

These adjustments are described by Company witness Ms. Turner in her Direct Testimony. Further, each of the Company's adjustments for purposes of interim rates are set forth in Volume 1, Direct Schedules B-3 (IR) (Rate Base Adjustments), B-7 (IR) (Operating Income Adjustments), B-9 (IR) (Interest Synchronization Adjustment), B-10 (IR) (Summary of Revenue Requirements), and C-6 (IR) (Capital Structure and Rate of Return Calculations).

The Company notes that although it is proposing a new allocation methodology for the Adjusted Test Year CCOSS, the Company's Interim Test Year CCOSS uses the allocation methodology approved in the Company's last full rate case in the 2016 Rate Case.

4. Description and corresponding dollar amount of changes included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available (Policy Statement, Item 4, page 2)

A comparison of the changes included in interim rates as compared with Minnesota Power's 2016 Rate Case (Docket No. E015/GR-16-664) is contained along with this Petition in Volume 1, Direct Schedules C (IR) (Comparison of Proposed Interim Rates to Most Recent General Rate Case) and Schedules D (IR) (Comparison of Proposed Interim Rates to Most Recent Fiscal Year).

5. Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues (Policy Statement, Item 5, page 2)

The test year for Minnesota Power's general rate increase filing is the calendar year ending December 31, 2022. The cost of service study supporting the necessity for general rate relief shows a deficiency in revenue of $108.3 million under present rates. Present rates, as referred to in this Petition, are the rates authorized by the Commission in its final order in Docket Nos. E015/GR-16-664 and E015/GR-19-442. However, for purposes of interim rates Minnesota Power is requesting to increase Minnesota Power's interim test year revenues by $87.3 million, or approximately 14.23 percent above present rate components other than cost recovery riders that will remain on customer bills.

6. Certification by officer of the utility (Policy Statement, Item 6, page 2)

This Petition contains a Certification signed by Patrick L. Cutshall, ALLETE Vice President & Corporate Treasurer, affirming that this Interim Rate Petition complies with Minnesota Statutes.

7. Methods and procedures for refunding

Pursuant to Minn. Stat. § 216B.16, subd. 3, this filing contains Minnesota Power's Agreement and Undertaking of Refund.

8. Signature and title of the utility officer authorizing the proposed interim rates (Policy Statement, Item 7, page 2)

This Petition is signed by Patrick L. Cutshall, ALLETE Vice President & Corporate Treasurer.

9. Supporting schedules and workpapers (Policy Statement, Items 1-4, page 3)

The supporting schedules and workpapers described in the Commission's Policy Statement are included along with this Petition. These schedules include the rate base amounts, income statement amounts, revenue deficiencies, capital structures, and rates of return required for interim rates as compared to: (1) the same information for Minnesota Power's general rate increase Application (Schedules F (IR)); (2) the allowed amounts in Minnesota Power's 2016 Rate Case (Docket No. E015/GR-16-664) (Schedules C (IR)); and (3) the most recent actual year (Schedules D (IR)). The schedules and workpapers containing the jurisdictional cost of service study and supporting the interim rate data are included in the Volume 1, Schedules A (Interim Jurisdictional Financial Summary Schedules), and Schedules B (Proposed Interim Rate Schedules), and in Volume 4 Workpapers, Interim Rates, IR-1 and IR-2, and Volume 4, Workpapers, Cost of Service, COS-1 – Cost of Service Interim Rates.

10. Interim rate schedules; Revenue rate comparisons (Minn. R. 7825.3600)

The rate schedules containing proposed interim rates are included along with this Petition in Volume 1, Interim Tariff Sheets – Redlined and Interim Tariff Sheets – Clean. Consistent with Minn. Stat. § 216B.16, subd. 3, no change has been made in the existing rate design. Minnesota Power is proposing to apply a uniform percentage increase of 14.23 percent to all present rate components other than cost recovery riders that will remain on customer bills, which would provide an additional $87.3 million of base rate revenues on an annualized basis. Included with this Petition is a schedule of interim revenue impacts in the Comparison of Revenues – Present and Proposed Interim Rates, Volume 4 Workpapers, IR-1.

11. Customer notice (Minn. R. 7829.2400, Subp. 3; Minn. Stat. § 216B.16, subd. 1)

Pursuant to Minn. R. 7829.2400, Subp. 3 and Minn. Stat. § 216B.16, subd. 1, Minnesota Power proposes to send a notice to the counties and municipalities it serves in Minnesota and a bill insert to its electric customers in the State of Minnesota. The proposed notice to counties and municipalities and a proposed customer notice pursuant to Minn. Stat. § 216B.16, subd. 1, are included with this filing. Minnesota Power will work with Commission Staff immediately to revise the notices as necessary for prompt Commission approval so that Minnesota Power can include the customer notices with the first bills issued with the interim rates. In addition, Minnesota Power will publish a display advertisement in the newspapers of general circulation in all county seats in Minnesota Power's service territory as ordered by the Commission. The display advertisement will replicate the notice to the counties and municipalities, and will describe the rate schedules applicable to various customer classes. Minnesota Power's proposed customer notice, proposed notices to counties and municipalities, and proposed newspaper advertisement are included in this Volume 1.

12. Interim rate bills

The Commission's Policy Statement on Interim Rates suggests that changes in interim rates be shown on customer bills as a separate line item "if practical." The interim rate amount will be shown as a separate line item identified as "Interim Rate Adjustment" and will reflect the total amount of the interim charge applied to the bill.

C. Conclusion

Minnesota Power hereby respectfully submits this Notice and Petition for Interim Rates. If the Commission suspends the operation of the general rate schedules under Minn. Stat. § 216B.16, subd. 2, Minnesota Power respectfully requests that the Petition for Interim Rates be promptly considered and accepted by the Commission, and that the interim rate schedule be approved and made effective on January 1, 2022, pursuant to Minn. Stat. § 216B.16, subd. 3, subject to refund pending final Commission action on the general rate increase Application.

Dated: November 1, 2021

Respectfully submitted,

Patrick L. Cutshall
ALLETE Vice President & Corporate Treasurer
30 West Superior Street
Duluth, MN 55802
(218) 722-2625

Subscribed to before me this 1st day of November, 2021

Notary Public

SUSAN ROMANS
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2025

Volume 1 Index - Interim Rate Schedules

F. Comparison of Proposed Interim Rates to Proposed Test Year

Line No.	Description	Calculation Note	Proposed Interim Rates 2022
		(1)	(2)
1	Total Interim Retail Revenue		$613,659,194
2	Interim Revenue Deficiency		$87,341,793
3	Total Interim Revenue Percent Increase	Line 2 / Line 1	14.2329%

Line No.	Description	Calculation Note	Proposed Interim Rates 2022
		(1)	(2)
1	Average Rate Base		$2,056,120,621
2	Operating Income Before AFUDC		$78,694,642
3	AFUDC		$2,485,869
4	Operating Income	Line 2 + Line 3	$81,180,511
5	Rate of Return	Line 4 / Line 1	3.9482%
6	Required Rate of Return		6.9752%
7	Required Operating Income	Line 1 * Line 6	$143,418,526
8	Operating Income Deficiency	Line 7 - Line 4	$62,238,015
9	Gross Revenue Conversion Factor		1.40335
10	Revenue Deficiency	Line 8 * Line 9	$87,341,793
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$613,659,194
12	Required Percent Increase	Line 10 / Line 11	14.2329%

Line No.	Description	Proposed Interim Rates 2022
		(1)
1	Plant In Service	
2	Steam	$1,363,731,716
3	Hydro	$189,924,458
4	Wind	$701,161,540
5	Transmission	$698,508,020
6	Distribution	$666,417,408
7	General Plant	$205,637,403
8	Intangible Plant	$60,731,625
9	Plant In Service	$3,886,112,169
10		
11	Accumulated Depreciation and Amortization	
12	Steam	($684,621,867)
13	Hydro	($40,803,571)
14	Wind	($174,165,052)
15	Transmission	($243,569,856)
16	Distribution	($318,622,695)
17	General Plant	($95,766,359)
18	Intangible Plant	($35,514,304)
19	Total Accumulated Depreciation and Amortization	($1,593,063,705)
20		
21	Net Plant Before CWIP	
22	Steam	$679,109,849
23	Hydro	$149,120,887
24	Wind	$526,996,487
25	Transmission	$454,938,164
26	Distribution	$347,794,713
27	General Plant	$109,871,044
28	Intangible Plant	$25,217,321
29	Total Net Plant Before CWIP	$2,293,048,464
30	Construction Work in Progress	$35,783,807
31	Utility Plant	$2,328,832,271
32		
33	Working Capital	
34	Fuel Inventory	$14,689,646
35	Materials and Supplies	$24,599,288
36	Prepayments	$24,230,206
37	Cash Working Capital	($39,366,227)
38	Total Working Capital	$24,152,914
39		
40	Additions and Deductions	
41	Asset Retirement Obligation	
42	Electric Vehicle Program	
43	Workers Compensation Deposit	$71,223
44	Unamortized WPPI Transmission Amortization	($425,308)
45	Unamortized UMWI Transaction Cost	$987,318
46	Unamortized Boswell 1 and 2	($4,893,264)
47	Customer Advances	($1,762,180)
48	Other Deferred Credits - Hibbard	($298,251)
49	Wind Performance Deposit	($131,883)
50	Accumulated Deferred Income Taxes	($290,412,218)
51	Total Additions and Deductions	($296,864,563)
52		
53	**Total Average Rate Base**	**$2,056,120,621**

Line No.	Description	Proposed Interim Rates 2022
		(1)
1	Operating Revenue	
2	Sales by Rate Class	$603,414,102
3	Dual Fuel	$10,245,092
4	Intersystem Sales	$32,671,772
5	Sales for Resale	$99,658,724
6	Total Revenue from Sales	$745,989,689
7	Other Operating Revenue	$34,497,318
8	Total Operating Revenue	$780,487,008
9		
10	Operating Expenses Before AFUDC	
11	Operation and Maintenance Expenses	
12	Steam Production	($30,519,440)
13	Hydro Production	($4,460,500)
14	Wind Production	($15,417,511)
15	Other Power Supply	($1,594,103)
16	Purchased Power	($270,170,787)
17	Fuel	($80,955,983)
18	Total Production	($403,118,324)
19	Transmission	($47,480,572)
20	Distribution	($27,110,481)
21	Customer Accounting	($6,385,512)
22	Customer Credit Cards	($294,188)
23	Customer Service and Information	($1,515,636)
24	Conservation Improvement Program	($10,714,344)
25	Sales	($1,856)
26	Administrative and General	($59,529,378)
27	Charitable Contributions	($241,756)
28	Interest on Customer Deposits	($1,248,000)
29	Total Operation and Maintenance Expenses	($557,640,048)
30	Depreciation Expense	($132,205,265)
31	Amortization Expense	($6,978,591)
32	Taxes Other Than Income Taxes	($37,219,906)
33	Income Taxes	($6,461,923)
34	Deferred Income Taxes	$38,267,588
35	Investment Tax Credit	$445,778
36	Total Operating Expenses Before AFUDC	($701,792,366)
37		
38	Operating Income Before AFUDC	$78,694,642
39	Allowance for Funds Used During Construction	$2,485,869
40	**Total Operating Income**	**$81,180,511**

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Unadjusted Test Year 2022	Adjustments	Proposed Interim Rates 2022	Unadjusted Test Year 2022	Adjustments	Proposed Interim Rates 2022
		(1)	(2)	(3)	(4)	(5)	(6)
1	Plant In Service						
2	Steam	$1,626,700,783	($77,604,678)	$1,549,096,105	$1,431,963,301	($68,231,585)	$1,363,731,716
3	Hydro	$216,868,174	$2	$216,868,176	$189,924,582	($124)	$189,924,458
4	Wind	$811,271,466	($10,582,644)	$800,688,822	$710,466,012	($9,304,472)	$701,161,540
5	Solar	$203,277	($203,277)		$178,725	($178,725)	
6	Transmission	$1,150,479,098	($300,181,708)	$850,297,390	$943,640,580	($245,132,560)	$698,508,020
7	Distribution	$703,336,011	($2,358,310)	$700,977,702	$668,780,335	($2,362,927)	$666,417,408
8	General Plant	$243,607,764	($12,325,458)	$231,282,306	$216,546,374	($10,908,972)	$205,637,403
9	Intangible Plant	$68,305,427	($1)	$68,305,426	$60,717,656	$13,969	$60,731,625
10	Total Plant In Service	$4,820,772,000	($403,256,074)	$4,417,515,926	$4,222,217,566	($336,105,396)	$3,886,112,169
11							
12	Accumulated Depreciation and Amortization						
13	Steam	($751,946,100)	($26,431,692)	($778,377,792)	($661,382,595)	($23,239,272)	($684,621,867)
14	Hydro	($59,575,343)	$12,992,448	($46,582,895)	($52,188,004)	$11,384,433	($40,803,571)
15	Wind	($200,954,279)	$2,079,948	($198,874,331)	($175,993,785)	$1,828,732	($174,165,052)
16	Solar	($41,996)	$41,996		($36,924)	$36,924	
17	Transmission	($282,546,754)	($14,176,490)	($296,723,244)	($231,552,414)	($12,017,443)	($243,569,856)
18	Distribution	($292,091,290)	($43,004,920)	($335,096,210)	($277,739,859)	($40,882,836)	($318,622,695)
19	General Plant	($110,400,663)	$2,691,345	($107,709,318)	($98,136,705)	$2,370,346	($95,766,359)
20	Intangible Plant	($39,943,270)	$1	($39,943,270)	($35,506,136)	($8,168)	($35,514,304)
21	Total Accumulated Depreciation and Amortization	($1,737,499,696)	($65,807,363)	($1,803,307,059)	($1,532,536,421)	($60,527,284)	($1,593,063,705)
22							
23	Net Plant Before CWIP						
24	Steam	$874,754,683	($104,036,370)	$770,718,313	$770,580,706	($91,470,857)	$679,109,849
25	Hyrdo	$157,292,831	$12,992,450	$170,285,281	$137,736,578	$11,384,309	$149,120,887
26	Wind	$610,317,186	($8,502,696)	$601,814,490	$534,472,227	($7,475,740)	$526,996,487
27	Solar	$161,281	($161,281)		$141,801	($141,801)	
28	Transmission	$867,932,344	($314,358,198)	$553,574,146	$712,088,167	($257,150,003)	$454,938,164
29	Distribution	$411,244,721	($45,363,229)	$365,881,492	$391,040,477	($43,245,764)	$347,794,713
30	General Plant	$133,207,101	($9,634,113)	$123,572,988	$118,409,669	($8,538,625)	$109,871,044
31	Intangible Plant	$28,362,157	($1)	$28,362,156	$25,211,521	$5,800	$25,217,321
32	Total Net Plant Before CWIP	$3,083,272,304	($469,063,437)	$2,614,208,867	$2,689,681,145	($396,632,680)	$2,293,048,464
33	Construction Work in Progress	$42,350,037	($1)	$42,350,036	$35,782,907	$900	$35,783,807
34	Utility Plant	$3,125,622,341	($469,063,438)	$2,656,558,903	$2,725,464,052	($396,631,781)	$2,328,832,271
35							
36	Working Capital						
37	Fuel Inventory	$17,141,063		$17,141,063	$14,689,719	($74)	$14,689,646
38	Materials and Supplies	$26,140,329	$2,050,180	$28,190,509	$22,804,831	$1,794,457	$24,599,288
39	Prepayments	$130,343,704	($102,318,842)	$28,024,861	$115,146,644	($90,916,437)	$24,230,206
40	Cash Working Capital	($41,695,811)	($2,161,505)	($43,857,315)	($36,136,705)	($3,229,522)	($39,366,227)
41	Total Working Capital	$131,929,284	($102,430,167)	$29,499,117	$116,504,490	($92,351,576)	$24,152,914
42							
43	Additions and Deductions						
44	Asset Retirement Obligation	($114,186,313)	$114,186,313		($100,394,890)	$100,394,890	
45	Electric Vehicle Program	$209,150	($209,150)		$198,874	($198,874)	
46	Workers Compensation Deposit	$80,105	($0)	$80,105	$71,206	$16	$71,223
47	Unamortized WPPI Transmission Amortization	($517,730)	($0)	($517,730)	($424,650)	($658)	($425,308)
48	Unamortized UMWI Transaction Cost	$1,201,867	$0	$1,201,867	$985,790	$1,528	$987,318
49	Unamortized Boswell 1 and 2		($5,565,460)	($5,565,460)		($4,893,264)	($4,893,264)
50	Customer Advances	($1,762,180)	$0	($1,762,180)	($1,762,180)	$0	($1,762,180)
51	Other Deferred Credits - Hibbard	($339,222)	($0)	($339,222)	($298,251)	($0)	($298,251)
52	Wind Performance Deposit	($150,000)	$0	($150,000)	($131,883)	$0	($131,883)
53	Accumulated Deferred Income Taxes	($390,997,287)	$59,049,275	($331,948,012)	($341,719,927)	$51,307,709	($290,412,218)
54	Total Additions and Deductions	($506,461,610)	$167,460,978	($339,000,632)	($443,475,910)	$146,611,347	($296,864,563)
55							
56	**Total Average Rate Base**	**$2,751,090,016**	**($404,032,627)**	**$2,347,057,389**	**$2,398,492,632**	**($342,372,010)**	**$2,056,120,621**

The adjustments listed below are used to convert from the 2022 Unadjusted Test Year budget rate base to the rate base for Proposed Interim Rates. A bridge schedule from the 2022 Unadjusted Test Year budget rate base to the Proposed Interim Rates rate base is provided in Direct Schedule B-3(IR) for Minnesota Jurisdiction and B-4(IR) for Total Company.

B-3 (IR) Column		Reference
(2) (3) (4)	**Asset Retirement Obligations (ARO), Cost to Retire, and Decommissioning**	
	Exclude ARO from plant and accumulated depreciation balances, as required in MP's 2008 rate case, Docket 08-415. Include related cost to retire and decommissioning adjustments to increase accumulated depreciation instead.	Turner Direct, IV. A. 1-3.; Vol. 4, Workpaper ADJ-RB-1; Vol. 4, Workpaper ADJ-RB-2;Vol. 4, Workpaper ADJ-RB-3
(5)	**Boswell Units 1&2 Regulated Asset**	
	Regulatory asset and accumulated amortization included in rate base starting in 2018, per MP 2016 rate case decision (Docket 16-664), with balance amortized through 2022. Company is proposing the final year of amortization in 2022 be amortized over three years.	Turner Direct, IV. A. 4.; Vol. 4, Workpaper ADJ-RB-4
(6)	**Boswell Unit 3 Environmental Project**	
	Reduce plant and accumulated depreciation balances as required in MP's 2009 rate case, Docket 09-1151.	Turner Direct, IV. A. 5.; Vol. 4, Workpaper ADJ-RB-5
(7)	**EV Program**	
	Exclude deferral of Electric Vehicle Program ("EV Program") expenses until subsequent rate case. Deferral approved in Docket No. E015/M-20-638.	Turner Direct, IV. A. 6.; Vol. 4, Workpaper ADJ-RB-6
(8)	**EVSE Project**	
	Exclude Electric Vehicle Service Equipment Project ("EVSE Project") capital cost until subsequent rate case. Deferral approved in Docket No. E015/M-21-257.	Turner Direct, IV. A. 7.; Vol. 4, Workpaper ADJ-RB-7
(9)	**Pro Rata Accumulated Deferred Income Tax ("ADIT")**	
	Pro Rata ADIT methodology applies to only Proposed Interim Rates, per Commission decision in MP 2016 rate case (Docket 16-664).	Turner Direct, VI. A. 8.; Vol. 4, Workpaper ADJ-RB-8
(10)	**Aircraft Hangar**	
	Net plant balance of corporate aircraft hangar is removed from rate base because MP chose to forego rate recovery of any costs associated with the aircraft.	Turner Direct, IV. A. 9; Rostollan Direct, III. B.; Vol. 3, Sched. H - 10; Vol. 4, Workpaper ADJ-RB-9
(11)	**Continuing Cost Recovery Riders**	
	Projects in the test year budget that included in cost recovery riders after this rate case are removed from rate base to avoid double recovery.	Turner Direct, IV. A. 10.; Shimmin Direct, VI.; Vol. 4, Workpaper ADJ-RB-10
(12)	**DC Line Addition**	
	Increase to Materials and Supplies due to a Major Supply Agreement that is expected to continue.	Turner Direct, IV. A. 11.; Vol. 4, Workpaper ADJ-RB-11
(13)	**Prepaid Other Post-Employment Benefits ("OPEB")**	
	Exclude Prepaid OPEB Asset and related ADIT for Interim Rates.	Turner Direct, IV. A. 12.; Cutshall Direct, V. B. 2.; Vol. 4, Workpaper ADJ-RB-12
(14)	**Prepaid Pension Asset**	
	Exclude prepaid pension asset and related ADIT for Interim Rates.	Turner Direct, IV. A. 13.; Cutshall Direct, V. A. 2; Vol. 4, Workpaper ADJ-RB-13
(15)	**Cash Working Capital**	
	Cash working capital is adjusted to reflect the impact of various O&M expense adjustments to the test year budget and tax impacts.	Turner Direct, IV. A. 14; Vol. 4, Workpaper ADJ-RB-14
(16)	**Changes in Allocations Due to Adjustments (MN Jurisdictional)**	
	The adjustments made in the adjusted versions of class cost-of-service studies may cause changes in allocation factors that have to be accounted for when bridging from an unadjusted to an adjusted CCOSS.	Turner Direct, IV. A. 15; Vol. 4, Workpaper ADJ-RB-15

Line No.	Description	Unadjusted Test Year 2022	Asset Retirement Obligation	Cost to Retire	Decommissioning	Boswell 1 and 2 Regulated Asset	Boswell 3 Environmental Project	EV Program	EVSE Project	Pro Rata ADIT
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Plant In Service									
2	Steam	$1,431,963,301	($54,839,819)				($13,391,767)			
3	Hydro	$189,924,582								
4	Wind	$710,466,012	($9,304,472)							
5	Solar	$178,725								
6	Transmission	$943,640,580								
7	Distribution	$668,780,335							($1,301,151)	
8	General Plant	$216,546,374								
9	Intangible Plant	$60,717,656								
10	Total Plant In Service	$4,222,217,566	($64,144,291)				($13,391,767)		($1,301,151)	
11										
12	Accumulated Depreciation and Amortization									
13	Steam	($661,382,595)	$31,839,324		($61,496,671)		$6,418,075			
14	Hydro	($52,188,004)		$11,384,398						
15	Wind	($175,993,785)	$2,413,206		($584,475)					
16	Solar	($36,924)								
17	Transmission	($231,552,414)		($23,736,401)						
18	Distribution	($277,739,859)		($41,164,005)					$56,288	
19	General Plant	($98,136,705)		$1,439,493						
20	Intangible Plant	($35,506,136)								
21	Total Accumulated Depreciation and Amortization	($1,532,536,421)	$34,252,530	($52,076,514)	($62,081,146)		$6,418,075		$56,288	
22										
23	Net Plant Before CWIP									
24	Steam	$770,580,706	($23,000,495)		($61,496,671)		($6,973,693)			
25	Hyrdo	$137,736,578		$11,384,398						
26	Wind	$534,472,227	($6,891,266)		($584,475)					
27	Solar	$141,801								
28	Transmission	$712,088,167		($23,736,401)						
29	Distribution	$391,040,477		($41,164,005)					($1,244,862)	
30	General Plant	$118,409,669		$1,439,493						
31	Intangible Plant	$25,211,521								
32	Total Net Plant Before CWIP	$2,689,681,145	($29,891,761)	($52,076,514)	($62,081,146)		($6,973,693)		($1,244,862)	
33	Construction Work in Progress	$35,782,907								
34	Utility Plant	$2,725,464,052	($29,891,761)	($52,076,514)	($62,081,146)		($6,973,693)		($1,244,862)	
35										
36	Working Capital									
37	Fuel Inventory	$14,689,719								
38	Materials and Supplies	$22,804,831								
39	Prepayments	$115,146,644								
40	Cash Working Capital	($36,136,705)								
41	Total Working Capital	$116,504,490								
42										
43	Additions and Deductions									
44	Asset Retirement Obligation	($100,394,890)	$100,394,890							
45	Electric Vehicle Program	$198,874						($198,838)		
46	Workers Compensation Deposit	$71,206								
47	Unamortized WPPI Transmission Amortization	($424,650)								
48	Unamortized UMWI Transaction Cost	$985,790								
49	Unamortized Boswell 1 and 2					($4,893,264)				
50	Customer Advances	($1,762,180)								
51	Other Deferred Credits - Hibbard	($298,251)								
52	Wind Performance Deposit	($131,883)								
53	Accumulated Deferred Income Taxes	($341,719,927)	$4,680,020			$1,406,421	$1,751,265		($12,843)	($587,257)
54	Total Additions and Deductions	($443,475,910)	$105,074,910			($3,486,842)	$1,751,265	($198,838)	($12,843)	($587,257)
55										
56	**Total Average Rate Base**	**$2,398,492,632**	**$75,183,149**	**($52,076,514)**	**($62,081,146)**	**($3,486,842)**	**($5,222,428)**	**($198,838)**	**($1,257,706)**	**($587,257)**

Line No.	Description	Aircraft Hangar	Continuing Cost Recovery Riders	DC Line Addition	OPEB	Prepaid Pension	CWC O&M	Changes in Allocations due to Adjustments	Total Adjustments	Proposed Interim Rates 2022
		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	Plant In Service									
2	Steam							$1	($68,231,585)	$1,363,731,716
3	Hydro							($124)	($124)	$189,924,458
4	Wind								($9,304,472)	$701,161,540
5	Solar		($178,725)						($178,725)	
6	Transmission		($246,148,829)					$1,016,271	($245,132,558)	$698,508,022
7	Distribution		($1,055,956)					($5,822)	($2,362,929)	$666,417,407
8	General Plant	($1,485,384)	($9,473,406)					$49,819	($10,908,971)	$205,637,404
9	Intangible Plant							$13,969	$13,969	$60,731,625
10	Total Plant In Service	($1,485,384)	($256,856,916)					$1,074,114	($336,105,394)	$3,886,112,171
11										
12	Accumulated Depreciation and Amortization									
13	Steam							($0)	($23,239,272)	($684,621,867)
14	Hydro							$34	$11,384,433	($40,803,571)
15	Wind							$2	$1,828,732	($174,165,052)
16	Solar		$36,924						$36,924	
17	Transmission		$12,065,209					($346,250)	($12,017,442)	($243,569,856)
18	Distribution		$222,463					$2,418	($40,882,836)	($318,622,694)
19	General Plant	$513,306	$440,124					($22,577)	$2,370,346	($95,766,359)
20	Intangible Plant							($8,169)	($8,169)	($35,514,304)
21	Total Accumulated Depreciation and Amortization	$513,306	$12,764,720					($374,542)	($60,527,284)	($1,593,063,705)
22										
23	Net Plant Before CWIP									
24	Steam							$1	($91,470,857)	$679,109,848
25	Hyrdo							($89)	$11,384,309	$149,120,887
26	Wind							$2	($7,475,740)	$526,996,487
27	Solar		($141,801)						($141,801)	
28	Transmission		($234,083,620)					$670,021	($257,150,000)	$454,938,166
29	Distribution		($833,493)					($3,404)	($43,245,764)	$347,794,712
30	General Plant	($972,078)	($9,033,282)					$27,241	($8,538,625)	$109,871,044
31	Intangible Plant							$5,800	$5,800	$25,217,321
32	Total Net Plant Before CWIP	($972,078)	($244,092,196)					$699,572	($396,632,679)	$2,293,048,466
33	Construction Work in Progress							$901	$901	$35,783,808
34	Utility Plant	($972,078)	($244,092,196)					$700,473	($396,631,778)	$2,328,832,274
35										
36	Working Capital									
37	Fuel Inventory							($74)	($74)	$14,689,646
38	Materials and Supplies			$1,789,005				$5,452	$1,794,457	$24,599,288
39	Prepayments				($19,466,562)	($71,507,023)		$57,148	($90,916,437)	$24,230,207
40	Cash Working Capital						($2,099,169)	($1,130,355)	($3,229,524)	($39,366,228)
41	Total Working Capital			$1,789,005	($19,466,562)	($71,507,023)	($2,099,169)	($1,067,829)	($92,351,577)	$24,152,913
42										
43	Additions and Deductions									
44	Asset Retirement Obligation								$100,394,890	
45	Electric Vehicle Program							($36)	($198,874)	$0
46	Workers Compensation Deposit							$16	$16	$71,223
47	Unamortized WPPI Transmission Amortization							($658)	($658)	($425,308)
48	Unamortized UMWI Transaction Cost							$1,528	$1,528	$987,318
49	Unamortized Boswell 1 and 2								($4,893,264)	($4,893,264)
50	Customer Advances							($0)	($0)	($1,762,180)
51	Other Deferred Credits - Hibbard							($0)	($0)	($298,251)
52	Wind Performance Deposit							$0	$0	($131,883)
53	Accumulated Deferred Income Taxes	($2,465)	$9,997,198		$6,445,626	$27,789,182		($159,437)	$51,307,709	($290,412,218)
54	Total Additions and Deductions	($2,465)	$9,997,198		$6,445,626	$27,789,182		($158,587)	$146,611,347	($296,864,563)
55										
56	**Total Average Rate Base**	**($974,543)**	**($234,094,998)**	**$1,789,005**	**($13,020,936)**	**($43,717,841)**	**($2,099,169)**	**($525,943)**	**($342,372,008)**	**$2,056,120,623**

Line No.	Description	Unadjusted Test Year 2022	Asset Retirement Obligation	Cost to Retire	Decommissioning	Boswell 1 and 2 Regulated Asset	Boswell 3 Environmental Project	EV Program	EVSE Project	Pro Rata ADIT
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Plant In Service									
2	Steam	$1,626,700,783	($62,373,261)				($15,231,418)			
3	Hydro	$216,868,174								
4	Wind	$811,271,466	($10,582,644)							
5	Solar	$203,277								
6	Transmission	$1,150,479,098								
7	Distribution	$703,336,011							($1,301,151)	
8	General Plant	$243,607,764								
9	Intangible Plant	$68,305,427								
10	Total Plant In Service	$4,820,772,000	($72,955,905)				($15,231,418)		($1,301,151)	
11										
12	Accumulated Depreciation and Amortization									
13	Steam	($751,946,100)	$36,213,148		($69,944,577)		$7,299,737			
14	Hydro	($59,575,343)		$12,992,448						
15	Wind	($200,954,279)	$2,744,712		($664,766)					
16	Solar	($41,996)								
17	Transmission	($282,546,754)		($28,910,269)						
18	Distribution	($292,091,290)		($43,298,727)					$59,207	
19	General Plant	($110,400,663)		$1,619,012						
20	Intangible Plant	($39,943,270)								
21	Total Accumulated Depreciation and Amortization	($1,737,499,696)	$38,957,860	($57,597,536)	($70,609,343)		$7,299,737		$59,207	
22										
23	Net Plant Before CWIP									
24	Steam	$874,754,683	($26,160,113)		($69,944,577)		($7,931,681)			
25	Hyrdo	$157,292,831		$12,992,448						
26	Wind	$610,317,186	($7,837,932)		($664,766)					
27	Solar	$161,281								
28	Transmission	$867,932,344		($28,910,269)						
29	Distribution	$411,244,721		($43,298,727)					($1,241,943)	
30	General Plant	$133,207,101		$1,619,012						
31	Intangible Plant	$28,362,157								
32	Total Net Plant Before CWIP	$3,083,272,304	($33,998,045)	($57,597,536)	($70,609,343)		($7,931,681)		($1,241,943)	
33	Construction Work in Progress	$42,350,037								
34	Utility Plant	$3,125,622,341	($33,998,045)	($57,597,536)	($70,609,343)		($7,931,681)		($1,241,943)	
35										
36	Working Capital									
37	Fuel Inventory	$17,141,063								
38	Materials and Supplies	$26,140,329								
39	Prepayments	$130,343,704								
40	Cash Working Capital	($41,695,811)								
41	Total Working Capital	$131,929,284								
42										
43	Additions and Deductions									
44	Asset Retirement Obligation	($114,186,313)	$114,186,313							
45	Electric Vehicle Program	$209,150						($209,150)		
46	Workers Compensation Deposit	$80,105								
47	Unamortized WPPI Transmission Amortization	($517,730)								
48	Unamortized UMWI Transaction Cost	$1,201,867								
49	Unamortized Boswell 1 and 2					($5,565,460)				
50	Customer Advances	($1,762,180)								
51	Other Deferred Credits - Hibbard	($339,222)								
52	Wind Performance Deposit	($150,000)								
53	Accumulated Deferred Income Taxes	($390,997,287)	$5,340,812			$1,599,624	$1,991,839		($13,510)	($672,541)
54	Total Additions and Deductions	($506,461,610)	$119,527,125			($3,965,836)	$1,991,839	($209,150)	($13,510)	($672,541)
55										
56	**Total Average Rate Base**	**$2,751,090,016**	**$85,529,079**	**($57,597,536)**	**($70,609,343)**	**($3,965,836)**	**($5,939,842)**	**($209,150)**	**($1,255,453)**	**($672,541)**

Line No.	Description	Aircraft Hangar	Continuing Cost Recovery Riders	DC Line Addition	OPEB	Prepaid Pension	CWC O&M	Changes in Allocations due to Adjustments	Total Adjustments	Proposed Interim Rates 2022
		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	Plant In Service									
2	Steam								($77,604,679)	$1,549,096,104
3	Hydro									$216,868,174
4	Wind								($10,582,644)	$800,688,822
5	Solar		($203,277)						($203,277)	
6	Transmission		($300,181,705)						($300,181,705)	$850,297,394
7	Distribution		($1,057,160)						($2,358,311)	$700,977,701
8	General Plant	($1,670,625)	($10,654,828)						($12,325,453)	$231,282,311
9	Intangible Plant									$68,305,427
10	Total Plant In Service	($1,670,625)	($312,096,970)						($403,256,068)	$4,417,515,932
11										
12	Accumulated Depreciation and Amortization									
13	Steam								($26,431,692)	($778,377,792)
14	Hydro								$12,992,448	($46,582,895)
15	Wind								$2,079,946	($198,874,333)
16	Solar		$41,996						$41,996	
17	Transmission		$14,733,780						($14,176,488)	($296,723,243)
18	Distribution		$234,600						($43,004,919)	($335,096,209)
19	General Plant	$577,320	$495,011						$2,691,343	($107,709,320)
20	Intangible Plant									($39,943,270)
21	Total Accumulated Depreciation and Amortization	$577,320	$15,505,388						($65,807,366)	($1,803,307,062)
22										
23	Net Plant Before CWIP									
24	Steam								($104,036,371)	$770,718,312
25	Hyrdo								$12,992,448	$170,285,279
26	Wind								($8,502,698)	$601,814,488
27	Solar		($161,281)						($161,281)	
28	Transmission		($285,447,924)						($314,358,193)	$553,574,151
29	Distribution		($822,560)						($45,363,230)	$365,881,492
30	General Plant	($1,093,305)	($10,159,817)						($9,634,110)	$123,572,991
31	Intangible Plant									$28,362,157
32	Total Net Plant Before CWIP	($1,093,305)	($296,591,582)						($469,063,434)	$2,614,208,870
33	Construction Work in Progress									$42,350,037
34	Utility Plant	($1,093,305)	($296,591,582)						($469,063,434)	$2,656,558,907
35										
36	Working Capital									
37	Fuel Inventory									$17,141,063
38	Materials and Supplies			$2,050,180					$2,050,180	$28,190,509
39	Prepayments				($21,894,224)	($80,424,617)			($102,318,840)	$28,024,863
40	Cash Working Capital						($2,161,507)		($2,161,507)	($43,857,317)
41	Total Working Capital			$2,050,180	($21,894,224)	($80,424,617)	($2,161,507)		($102,430,167)	$29,499,117
42										
43	Additions and Deductions									
44	Asset Retirement Obligation								$114,186,313	
45	Electric Vehicle Program								($209,150)	$0
46	Workers Compensation Deposit									$80,105
47	Unamortized WPPI Transmission Amortization									($517,730)
48	Unamortized UMWI Transaction Cost									$1,201,867
49	Unamortized Boswell 1 and 2								($5,565,460)	($5,565,460)
50	Customer Advances									($1,762,180)
51	Other Deferred Credits - Hibbard									($339,222)
52	Wind Performance Deposit									($150,000)
53	Accumulated Deferred Income Taxes	($2,773)	$12,127,861		$7,355,711	$31,322,253			$59,049,277	($331,948,010)
54	Total Additions and Deductions	($2,773)	$12,127,861		$7,355,711	$31,322,253			$167,460,979	($339,000,631)
55										
56	**Total Average Rate Base**	**($1,096,078)**	**($284,463,721)**	**$2,050,180**	**($14,538,513)**	**($49,102,364)**	**($2,161,507)**		**($404,032,622)**	**$2,347,057,394**

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Unadjusted Test Year 2022	Adjustments	Proposed Interim Rates 2022	Unadjusted Test Year 2022	Adjustments	Proposed Interim Rates 2022
		(1)	(2)	(3)	(4)	(5)	(6)
1	Operating Revenue						
2	Sales by Rate Class	$688,496,038	$7,414,356	$695,910,394	$595,999,746	$7,414,356	$603,414,102
3	Dual Fuel	$10,231,437	$13,655	$10,245,092	$10,231,437	$13,655	$10,245,092
4	Intersystem Sales	$38,067,674		$38,067,674	$32,671,926	($154)	$32,671,772
5	LP Demand Response						
6	Sales for Resale	$115,185,926		$115,185,926	$99,659,035	($312)	$99,658,724
7	Total Revenue from Sales	$851,981,075	$7,428,010	$859,409,086	$738,562,145	$7,427,545	$745,989,689
8	Other Operating Revenue	$124,307,444	($82,710,795)	$41,596,649	$108,119,043	($73,621,725)	$34,497,318
9	Total Operating Revenue	$976,288,520	($75,282,785)	$901,005,735	$846,681,188	($66,194,180)	$780,487,008
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production	($33,760,108)	($1,367,000)	($35,127,108)	($29,348,005)	($1,171,435)	($30,519,440)
14	Hydro Production	($5,146,274)		($5,146,274)	($4,460,513)	$12	($4,460,500)
15	Wind Production	($17,535,442)		($17,535,442)	($15,417,511)		($15,417,511)
16	Solar Production	($97,484)	$97,484		($85,710)	$85,710	
17	Other Power Supply	($1,813,088)		($1,813,088)	($1,594,103)		($1,594,103)
18	Purchased Power	($313,101,547)	($60,000)	($313,161,547)	($270,119,031)	($51,756)	($270,170,787)
19	Fuel	($94,465,966)		($94,465,966)	($80,956,388)	$405	($80,955,983)
20	Total Production	($465,919,909)	($1,329,516)	($467,249,425)	($401,981,261)	($1,137,063)	($403,118,324)
21	Transmission	($91,761,777)	$33,963,434	($57,798,343)	($75,264,415)	$27,783,844	($47,480,572)
22	Distribution	($28,591,273)	$5,000	($28,586,273)	($27,120,710)	$10,229	($27,110,481)
23	Customer Accounting	($6,438,438)		($6,438,438)	($6,385,512)		($6,385,512)
24	Customer Credit Cards	($350,004)	$55,816	($294,188)	($350,004)	$55,816	($294,188)
25	Customer Service and Information	($1,977,374)	$445,860	($1,531,514)	($1,956,874)	$441,237	($1,515,636)
26	Conservation Improvement Program	($11,891,509)	$1,177,165	($10,714,344)	($11,891,509)	$1,177,165	($10,714,344)
27	Sales	($104,872)	$103,016	($1,856)	($104,872)	$103,016	($1,856)
28	Administrative and General	($73,149,713)	$5,975,282	($67,174,431)	($64,804,821)	$5,275,443	($59,529,378)
29	Charitable Contributions	($882,662)	$610,757	($271,905)	($784,611)	$542,855	($241,756)
30	Interest on Customer Deposits	($1,248,000)	$0	($1,248,000)	($1,248,000)	$0	($1,248,000)
31	Total Operation and Maintenance Expenses	($682,315,531)	$41,006,814	($641,308,717)	($591,892,589)	$34,252,541	($557,640,048)
32	Depreciation Expense	($157,573,503)	$7,980,042	($149,593,462)	($138,764,052)	$6,558,787	($132,205,265)
33	Amortization Expense	($7,307,508)	($557,430)	($7,864,938)	($6,487,174)	($491,417)	($6,978,591)
34	Taxes Other Than Income Taxes	($60,869,366)	$19,135,412	($41,733,954)	($52,910,337)	$15,690,431	($37,219,906)
35	Income Taxes	($9,432,301)	($101,577)	($9,533,878)	($7,395,631)	$933,708	($6,461,923)
36	Deferred Income Taxes	$43,703,802	($0)	$43,703,802	$38,254,660	$12,928	$38,267,588
37	Investment Tax Credit	$510,490	$0	$510,490	$445,711	$67	$445,778
38	Total Operating Expenses Before AFUDC	($873,283,917)	$67,463,261	($805,820,657)	($758,749,412)	$56,957,047	($701,792,366)
39							
40	Operating Income Before AFUDC	$103,004,602	($7,819,524)	$95,185,078	$87,931,775	($9,237,133)	$78,694,642
41	Allowance for Funds Used During Construction	$2,942,167	($0)	$2,942,167	$2,485,807	$63	$2,485,869
42	**Total Operating Income**	**$105,946,769**	**($7,819,524)**	**$98,127,245**	**$90,417,582**	**($9,237,071)**	**$81,180,511**

The adjustments listed below are used to convert from the Unadjusted Test Year budget operating income to the operating income for Proposed Interim Rates. A bridge schedule from the Unadjusted Test Year budget operating income to the Proposed Interim Rates operating income is provided in Direct Schedule B-7(IR) for Minnesota Jurisdiction and Direct Schedule B-8(IR) for Total Company.

B-7 (IR) Column		Reference
(2)	**Advertising Expense**	
	Consistent with Commission decision in MP's 2016 rate case, exclude portion of test year budgeted advertising expense that doesn't qualify for rate recovery based on Commission's Statement of Policy on Advertising.	Turner Direct, V. B. 1.; Vol. 3, Sched. G-1; Vol. 4, Workpaper ADJ-IS-1
(3)	**Charitable Contributions**	
	Consistent with Commission decision in MP's 2016 rate case, exclude 50 percent of average actual expense for qualified charitable contributions in previous three years. This is consistent with Commission's Statement of Policy on Charitable Contributions and decision in MP's 2016 rate case.	Turner Direct, V. B. 2.; Vol. 3, Sched. G-2; Vol. 4, Workpaper ADJ-IS-2
(4)	**Economic Development**	
	Exclude 50 percent of 2022 test year Economic and Community Development expense, consistent with Commission decisions in MP's 2008, 2009, and 2016 rate cases. Adjustment not included for Proposed test Year.	Turner Direct, V. B. 3; Vol. 3, Sched. G-5; Vol. 4, Workpaper ADJ-IS-3
(5)	**Organization Dues**	
	Excluded non-allowable legislative lobbying dues, in compliance with Commission's Statement of Policy on Organization Dues and treatment in MP's 2016 rate case.	Turner Direct, V. B. 4.; Vol. 3, Sched. G-3; Vol. 4, Workpaper ADJ-IS-4
(6)	**Employee Expenses**	
	Excluded certain categories of travel and lodging, food and beverage, gift, social club dues, recreation, and entertainment expenses. Excluded lobbying-related expenses that were included in employee expense accounts, beyond the majority of lobbying expenses that are recorded in separate non-regulated expense accounts.	Turner Direct, V. B. 5.; Rostollan Direct V. B.; Vol. 3, Sched. H-1; Vol. 4, Workpaper ADJ-IS-5
(7)	**Incentive Compensation**	
	Excludes Annual Incentive Plan (AIP) greater than 20 percent of individual base pay, consistent with prior Commission orders. Also excludes Long-Term Incentive Plan (LTIP), Supplemental Executive Retirement Plan (SERP), Executive Deferral Plan, and Legacy Employment Agreements.	Turner Direct, V. B. 6.; Krollman Direct, III. B.; Vol. 4, Workpaper ADJ-IS-6
(8)	**Investor Relations Expenses**	
	Excluded 50 percent of Investor Relations expense, consistent with recent Commission decisions.	Turner Direct, V. B. 7.; Rostallan Direct, III. C.; Vol. 4, Workpaper ADJ-IS-7
(9)	**Credit Card Fees**	
	Exclude projected test year over-collection of credit card processing fees based on approved methodlogy in MP's 2016 rate case. Over-collection proposed to be amortized over three years as a negative expense.	Turner Direct, V. B. 8.; Vol. 4, Workpaper ADJ-IS-8
(10) (11)	**Asset Retirement Obligations (ARO) and Decommissioning**	
	Exclude ARO from depreciation, amortization expense as required in MP's 2008 rate case, Docket 08-415, and include decommissioning expense instead.	Turner Direct, V. B. 9-10.; Vol. 4, Workpaper ADJ-IS-9, ADJ-IS10.
(12)	**Boswell Units 1&2 Regulated Asset**	

	Include amortization expense associated with Boswell Units 1 & 2 regulatory asset per MP 2016 rate case decision (Docket 16-664), with balance amortized through 2022. Final amortization expense is reduced and is proposed to be spread over three years.	Turner Direct, V. B. 11; Vol. 4, Workpaper ADJ-IS-11
(13)	**Boswell Unit 3 Environmental Project**	
	Remove a portion of Boswell Unit 3 and Common depreciation expense related to 2017, as ordered in MP's 2018 Remaining Life Depreciation Petition (Docket 18-544).	Turner Direct, V. B. 12.; Vol. 4, Workpaper ADJ-IS-12
(14)	**EVSE Project**	
	Excluding depreciation expense of Electric Vehicle Service Equipment Project ("EVSE Project") capital cost until subsequent rate case. Docket No. E015/M-21-257.	Turner Direct, V. B. 13.; Vol. 4, Workpaper ADJ-IS-13
(15)	**Service Center Sales**	
	Return revenue to customers related to regulatory liability balances associated with sale of Aurora, Chisholm and Crosby service centers, sale of land near Boswell, and loader transfer. Proposed to be amortized over three years to return to customers.	Turner Direct, V. B. 14., Vol. 4, Workpaper ADJ-IS-14
(16)	**Conservation Expense**	
	Conservation expense is adjusted to remove the amount in the test year budget and instead include projected test year expenditures based on MP's 2021-2023 Conservation Improvement Program (CIP) Triennial Plan. Docket No. E015/CIP-20-467.	Turner Direct, V. B. 15.; Vol. 4, Workpaper ADJ-IS-15
(17)	**Aircraft Hangar**	
	Remove depreciation expense for corporate aircraft hangar because MP chose to forego rate recovery of any costs associated with the aircraft.	Turner Direct, V. B. 16.; Vol. 4, Workpaper ADJ-IS-16
(18)	**Customer Affordability of Residential Electricity ("CARE") Rider**	
	CARE Rider discounts and surcharge collections are accumulated in a tracker and adjusted as necessary between rate cases in a separate docket. Therefore, the Residential class discount and the Affordability Surcharge revenue from all customer classes is removed from retail Sales by Rate Class for cost-of-service purposes.	Turner Direct, V. B. 17.; Vol. 4, Workpaper ADJ-IS-17
(19)	**CIP Incentive**	
	Remove CIP incentive from rate case revenue because the CIP incentive is intended to provide an incentive to the Company for conservation program performance.	Turner Direct, V. B. 18.; Vol. 4, Workpaper ADJ-IS-18
(20)	**CIP Carrying Charge**	
	Remove CIP tracker carrying charge from rate case revenue because the CIP tracker provides a return on outstanding tracker balances.	Turner Direct, V. B. 19.; Vol. 4, Workpaper ADJ-IS-19
(21)	**CPA Incentive**	
	Adjustments for timing of when CIP/CPA revenue is collected through customer billings vs. recorded as revenue on MP's books.	Turner Direct, V. B. 20.; Vol. 4, Workpaper ADJ-IS-20
(22)	**CPA**	
	Total CPA revenue is removed from rate case because the CPA Rider will continue on customer bills outside of base rates.	Turner Direct, V. B. 21.; Vol. 4, Workpaper ADJ-IS-21
(23)	**Conservation Cost Recovery Charge (CCRC)**	
	CCRC credit amount for related to CIP-exempt customers included in the test year budget is removed from revenue because the CCRC credit amount is contained in the CIP tracker and corresponding rates are adjusted separately from base rates.	Turner Direct, V. B. 22; Vol. 4, Workpaper ADJ-IS-22
(24)	**Continuing Cost Recovery Riders**	
	Exclude Revenue, Other Operating Revenue, O&M expenses, depreciation expense, and taxes associated with projects in the test year budget that will continue to be included in cost recovery riders after this rate case to avoid double recovery.	Turner Direct, V. B. 23.; Shimmin Direct, VI.; Vol. 4, Workpaper ADJ-IS-23
(25)	**Rate Case Expense**	
	Test year budgeted retail Rate Case expenses proposed to be amortized over three years.	Turner Direct, V. B. 24.; Vol 4, Workpaper ADJ-IS-24
(26)	**Revenue Budget Corrections**	

	This includes minor differences to test year budgeted revenue to align with Schedules E-1 and E-2.	Turner Direct, V. B. 25.; Vol. 4, Workpaper ADJ-IS-25
(27)	**Excess ADIT**	
	Removes Tax Cut Refund Rider credit from revenue becaue Excess ADIT is included in rolled into base rates with Interim Rates.	Turner Direct, V. B. 26.; Armbruster Direct II. B.; Vol. 4, Workpaper ADJ-IS-26
(28)	**Boswell Inspection Costs**	
	Include additional inspection costs related Boswell as result of Administrative Law Judge (“ALJ”) recommnedation in Docket No. E999/AA-20-171.	Turner Direct, V. B. 28.; Vol. 4, Workpaper ADJ-IS-29
(29)	**Interest Synchronization**	
	Adjustment for interest expense deduction for income tax purposes to equal the weighted cost of debt multiplied by average rate base. Updated whenever there is a change in rate base, weighted cost of debt, or operating income.	Turner Direct, V. B. 29.; Vol. 4, Workpaper ADJ-IS-30
(30)	**Changes in Allocations Due to Adjustments (MN Jurisdictional)**	
	Adjustments to account for changes in allocation factors resulting from other adjustments accounted for when bridging from an unadjusted to an adjusted CCOSS.	Turner Direct, V. B. 30.; Vol. 4, Workpaper ADJ-IS-31

Line No.	Description	Unadjusted Test Year 2022	Advertising Expense	Charitable Contributions	Economic Development	Organizational Dues	Employee Expenses
		(1)	(2)	(3)	(4)	(5)	(6)
1	Operating Revenue						
2	Sales by Rate Class	$595,999,746					
3	Dual Fuel	$10,231,437					
4	Intersystem Sales	$32,671,926					
5	LP Demand Response						
6	Sales for Resale	$99,659,035					
7	Total Revenue from Sales	$738,562,145					
8	Other Operating Revenue	$108,119,043					
9	Total Operating Revenue	$846,681,188					
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production	($29,348,005)					
14	Hydro Production	($4,460,513)					
15	Wind Production	($15,417,511)					
16	Solar Production	($85,710)					
17	Other Power Supply	($1,594,103)					
18	Purchased Power	($270,119,031)					
19	Fuel	($80,956,388)					
20	Total Production	($401,981,261)					
21	Transmission	($75,264,415)					
22	Distribution	($27,120,710)	$4,730				
23	Customer Accounting	($6,385,512)					
24	Customer Credit Cards	($350,004)					
25	Customer Service and Information	($1,956,874)	$5,662		$4,096		
26	Conservation Improvement Program	($11,891,509)					
27	Sales	($104,872)	$103,016				
28	Administrative and General	($64,804,821)	$165,680		$273,868	$4,179	$486,617
29	Charitable Contributions	($784,611)		$543,036			
30	Interest on Customer Deposits	($1,248,000)					
31	Total Operation and Maintenance Expenses	($591,892,589)	$279,088	$543,036	$277,964	$4,179	$486,617
32	Depreciation Expense	($138,764,052)					
33	Amortization Expense	($6,487,174)					
34	Taxes Other Than Income Taxes	($52,910,337)					
35	Income Taxes	($7,395,631)	($80,215)	($156,079)	($79,892)	($1,201)	($139,863)
36	Deferred Income Taxes	$38,254,660					
37	Investment Tax Credit	$445,711					
38	Total Operating Expenses Before AFUDC	($758,749,412)	$198,872	$386,956	$198,072	$2,978	$346,754
39							
40	Operating Income Before AFUDC	$87,931,775	$198,872	$386,956	$198,072	$2,978	$346,754
41	Allowance for Funds Used During Construction	$2,485,807					
42	**Total Operating Income**	**$90,417,582**	**$198,872**	**$386,956**	**$198,072**	**$2,978**	**$346,754**

Line No.	Description	Incentive Compensation	Investor Relations	Credit Card Fees	Asset Retirement Obligation	Decommissioning	Boswell 1 and 2 Regulated Asset
		(7)	(8)	(9)	(10)	(11)	(12)
1	Operating Revenue						
2	Sales by Rate Class						
3	Dual Fuel						
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales						
8	Other Operating Revenue						
9	Total Operating Revenue						
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production						
14	Hydro Production						
15	Wind Production						
16	Solar Production						
17	Other Power Supply						
18	Purchased Power						
19	Fuel						
20	Total Production						
21	Transmission						
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards			$55,816			
25	Customer Service and Information						
26	Conservation Improvement Program						
27	Sales						
28	Administrative and General	$5,395,477	$181,952				
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses	$5,395,477	$181,952	$55,816			
32	Depreciation Expense				$362,978	($928,836)	
33	Amortization Expense				$685,883		($1,175,987)
34	Taxes Other Than Income Taxes						
35	Income Taxes	($1,550,768)	($52,297)	($16,043)	($301,464)	$266,966	$338,002
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	$3,844,709	$129,655	$39,773	$747,398	($661,870)	($837,985)
39							
40	Operating Income Before AFUDC	$3,844,709	$129,655	$39,773	$747,398	($661,870)	($837,985)
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**$3,844,709**	**$129,655**	**$39,773**	**$747,398**	**($661,870)**	**($837,985)**

Line No.	Description	Boswell 3 Environmental Project	EVSE Project	Service Center Sales	Conservation Expense	Aircraft Hangar	CARE
		(13)	(14)	(15)	(16)	(17)	(18)
1	Operating Revenue						
2	Sales by Rate Class						($0)
3	Dual Fuel						
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales						($0)
8	Other Operating Revenue			$409,560			
9	Total Operating Revenue			$409,560			($0)
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production						
14	Hydro Production						
15	Wind Production						
16	Solar Production						
17	Other Power Supply						
18	Purchased Power						
19	Fuel						
20	Total Production						
21	Transmission						
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards						
25	Customer Service and Information						
26	Conservation Improvement Program				$1,177,165		
27	Sales						
28	Administrative and General						
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses				$1,177,165		
32	Depreciation Expense	$518,169	$112,593			$54,877	
33	Amortization Expense						
34	Taxes Other Than Income Taxes						
35	Income Taxes	($148,932)	($32,362)	($117,716)	($338,341)	($15,773)	
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	$369,237	$80,232	($117,716)	$838,824	$39,104	
39							
40	Operating Income Before AFUDC	$369,237	$80,232	$291,844	$838,824	$39,104	($0)
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**$369,237**	**$80,232**	**$291,844**	**$838,824**	**$39,104**	**($0)**

Line No.	Description	CIP Incentive	CIP Carrying Charge	CPA Incentive	CPA	CCRC	Continuing Cost Recovery Riders
		(19)	(20)	(21)	(22)	(23)	(24)
1	Operating Revenue						
2	Sales by Rate Class			$2,089,215	($5,282,832)	$1,171,775	$75,415
3	Dual Fuel			$92,737	($238,418)		$3,005
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales			$2,181,952	($5,521,250)	$1,171,775	$78,419
8	Other Operating Revenue	($1,683,939)	($66,148)				($81,421,344)
9	Total Operating Revenue	($1,683,939)	($66,148)	$2,181,952	($5,521,250)	$1,171,775	($81,342,924)
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production						
14	Hydro Production						
15	Wind Production						
16	Solar Production						$97,484
17	Other Power Supply						
18	Purchased Power						($60,000)
19	Fuel						
20	Total Production						$37,484
21	Transmission						$33,963,434
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards						
25	Customer Service and Information						$435,999
26	Conservation Improvement Program						
27	Sales						
28	Administrative and General						
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses						$34,436,917
32	Depreciation Expense						$7,854,144
33	Amortization Expense						
34	Taxes Other Than Income Taxes						$19,135,412
35	Income Taxes	$483,998	$19,012	($627,137)	$1,586,918	($336,792)	$5,724,386
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	$483,998	$19,012	($627,137)	$1,586,918	($336,792)	$67,150,859
39							
40	Operating Income Before AFUDC	($1,199,942)	($47,136)	$1,554,815	($3,934,332)	$834,983	($14,192,065)
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**($1,199,942)**	**($47,136)**	**$1,554,815**	**($3,934,332)**	**$834,983**	**($14,192,065)**

Line No.	Description	Rate Case Expense	Revenue Budget Corrections	Excess ADIT	Boswell Inspection Costs	Interest Synchronization	Changes in Allocations due to Adjustments
		(25)	(26)	(27)	(28)	(29)	(30)
1	Operating Revenue						
2	Sales by Rate Class		$4,807	$9,355,979			($2)
3	Dual Fuel			$156,329			
4	Intersystem Sales						($154)
5	LP Demand Response						
6	Sales for Resale						($312)
7	Total Revenue from Sales		$4,807	$9,512,308			($468)
8	Other Operating Revenue						$9,140,146
9	Total Operating Revenue		$4,807	$9,512,308			$9,139,678
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production				($1,187,689)		$16,254
14	Hydro Production						$12
15	Wind Production						
16	Solar Production						($11,774)
17	Other Power Supply						
18	Purchased Power						$8,244
19	Fuel						$405
20	Total Production				($1,187,689)		$13,141
21	Transmission						($6,179,590)
22	Distribution						$5,499
23	Customer Accounting						
24	Customer Credit Cards						
25	Customer Service and Information						($4,520)
26	Conservation Improvement Program						
27	Sales						
28	Administrative and General	($1,344,072)					$111,742
29	Charitable Contributions						($181)
30	Interest on Customer Deposits						$0
31	Total Operation and Maintenance Expenses	($1,344,072)			($1,187,689)		($6,053,909)
32	Depreciation Expense						($1,415,142)
33	Amortization Expense						($1,314)
34	Taxes Other Than Income Taxes						($3,444,980)
35	Income Taxes	$386,313	($1,382)	($2,734,027)	$341,366	($1,965,828)	$482,859
36	Deferred Income Taxes						$12,928
37	Investment Tax Credit						$67
38	Total Operating Expenses Before AFUDC	($957,759)	($1,382)	($2,734,027)	($846,323)	($1,965,828)	($10,419,490)
39							
40	Operating Income Before AFUDC	($957,759)	$3,425	$6,778,280	($846,323)	($1,965,828)	($1,279,812)
41	Allowance for Funds Used During Construction						$63
42	**Total Operating Income**	**($957,759)**	**$3,425**	**$6,778,280**	**($846,323)**	**($1,965,828)**	**($1,279,749)**

Line No.	Description	Total Adjustments	Proposed Interim Rates 2022
		(31)	(32)
1	Operating Revenue		
2	Sales by Rate Class	$7,414,356	$603,414,102
3	Dual Fuel	$13,653	$10,245,090
4	Intersystem Sales	($154)	$32,671,772
5	LP Demand Response		
6	Sales for Resale	($312)	$99,658,724
7	Total Revenue from Sales	$7,427,543	$745,989,688
8	Other Operating Revenue	($73,621,725)	$34,497,318
9	Total Operating Revenue	($66,194,182)	$780,487,006
10			
11	Operating Expenses Before AFUDC		
12	Operation and Maintenance Expenses		
13	Steam Production	($1,171,435)	($30,519,440)
14	Hydro Production	$12	($4,460,500)
15	Wind Production		($15,417,511)
16	Solar Production	$85,710	
17	Other Power Supply		($1,594,103)
18	Purchased Power	($51,756)	($270,170,787)
19	Fuel	$405	($80,955,983)
20	Total Production	($1,137,063)	($403,118,324)
21	Transmission	$27,783,844	($47,480,572)
22	Distribution	$10,229	($27,110,481)
23	Customer Accounting		($6,385,512)
24	Customer Credit Cards	$55,816	($294,188)
25	Customer Service and Information	$441,237	($1,515,636)
26	Conservation Improvement Program	$1,177,165	($10,714,344)
27	Sales	$103,016	($1,856)
28	Administrative and General	$5,275,443	($59,529,379)
29	Charitable Contributions	$542,855	($241,756)
30	Interest on Customer Deposits	$0	($1,248,000)
31	Total Operation and Maintenance Expenses	$34,252,541	($557,640,048)
32	Depreciation Expense	$6,558,784	($132,205,268)
33	Amortization Expense	($491,417)	($6,978,591)
34	Taxes Other Than Income Taxes	$15,690,431	($37,219,906)
35	Income Taxes	$933,709	($6,461,922)
36	Deferred Income Taxes	$12,928	$38,267,588
37	Investment Tax Credit	$67	$445,778
38	Total Operating Expenses Before AFUDC	$56,957,044	($701,792,369)
39			
40	Operating Income Before AFUDC	($9,237,138)	$78,694,637
41	Allowance for Funds Used During Construction	$63	$2,485,869
42	**Total Operating Income**	**($9,237,075)**	**$81,180,506**

Line No.	Description	Unadjusted Test Year 2022	Advertising Expense	Charitable Contributions	Economic Development	Organizational Dues	Employee Expenses
		(1)	(2)	(3)	(4)	(5)	(6)
1	Operating Revenue						
2	Sales by Rate Class	$688,496,038					
3	Dual Fuel	$10,231,437					
4	Intersystem Sales	$38,067,674					
5	LP Demand Response						
6	Sales for Resale	$115,185,926					
7	Total Revenue from Sales	$851,981,075					
8	Other Operating Revenue	$124,307,444					
9	Total Operating Revenue	$976,288,520					
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production	($33,760,108)					
14	Hydro Production	($5,146,274)					
15	Wind Production	($17,535,442)					
16	Solar Production	($97,484)					
17	Other Power Supply	($1,813,088)					
18	Purchased Power	($313,101,547)					
19	Fuel	($94,465,966)					
20	Total Production	($465,919,909)					
21	Transmission	($91,761,777)					
22	Distribution	($28,591,273)	$5,000				
23	Customer Accounting	($6,438,438)					
24	Customer Credit Cards	($350,004)					
25	Customer Service and Information	($1,977,374)	$5,722		$4,139		
26	Conservation Improvement Program	($11,891,509)					
27	Sales	($104,872)	$103,016				
28	Administrative and General	($73,149,713)	$186,342		$308,022	$4,700	$547,303
29	Charitable Contributions	($882,662)		$610,757			
30	Interest on Customer Deposits	($1,248,000)					
31	Total Operation and Maintenance Expenses	($682,315,531)	$300,079	$610,757	$312,161	$4,700	$547,303
32	Depreciation Expense	($157,573,503)					
33	Amortization Expense	($7,307,508)					
34	Taxes Other Than Income Taxes	($60,869,366)					
35	Income Taxes	($9,432,301)	($86,249)	($175,544)	($89,721)	($1,351)	($157,306)
36	Deferred Income Taxes	$43,703,802					
37	Investment Tax Credit	$510,490					
38	Total Operating Expenses Before AFUDC	($873,283,917)	$213,830	$435,213	$222,440	$3,349	$389,997
39							
40	Operating Income Before AFUDC	$103,004,602	$213,830	$435,213	$222,440	$3,349	$389,997
41	Allowance for Funds Used During Construction	$2,942,167					
42	**Total Operating Income**	**$105,946,769**	**$213,830**	**$435,213**	**$222,440**	**$3,349**	**$389,997**

Line No.	Description	Incentive Compensation	Investor Relations	Credit Card Fees	Asset Retirement Obligation	Decommissioning	Boswell 1 and 2 Regulated Asset
		(7)	(8)	(9)	(10)	(11)	(12)
1	Operating Revenue						
2	Sales by Rate Class						
3	Dual Fuel						
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales						
8	Other Operating Revenue						
9	Total Operating Revenue						
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production						
14	Hydro Production						
15	Wind Production						
16	Solar Production						
17	Other Power Supply						
18	Purchased Power						
19	Fuel						
20	Total Production						
21	Transmission						
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards			$55,816			
25	Customer Service and Information						
26	Conservation Improvement Program						
27	Sales						
28	Administrative and General	$6,068,343	$204,643				
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses	$6,068,343	$204,643	$55,816			
32	Depreciation Expense				$412,841	($1,056,432)	
33	Amortization Expense				$780,104		($1,337,534)
34	Taxes Other Than Income Taxes						
35	Income Taxes	($1,744,163)	($58,818)	($16,043)	($342,876)	$303,640	$384,434
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	$4,324,180	$145,825	$39,773	$850,069	($752,792)	($953,100)
39							
40	Operating Income Before AFUDC	$4,324,180	$145,825	$39,773	$850,069	($752,792)	($953,100)
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**$4,324,180**	**$145,825**	**$39,773**	**$850,069**	**($752,792)**	**($953,100)**

Line No.	Description	Boswell 3 Environmental Project	EVSE Project	Service Center Sales	Conservation Expense	Aircraft Hangar	CARE
		(13)	(14)	(15)	(16)	(17)	(18)
1	Operating Revenue						
2	Sales by Rate Class						($0)
3	Dual Fuel						
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales						($0)
8	Other Operating Revenue			$460,636			
9	Total Operating Revenue			$460,636			($0)
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production						
14	Hydro Production						
15	Wind Production						
16	Solar Production						
17	Other Power Supply						
18	Purchased Power						
19	Fuel						
20	Total Production						
21	Transmission						
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards						
25	Customer Service and Information						
26	Conservation Improvement Program				$1,177,165		
27	Sales						
28	Administrative and General						
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses				$1,177,165		
32	Depreciation Expense	$589,351	$118,415			$61,721	
33	Amortization Expense						
34	Taxes Other Than Income Taxes						
35	Income Taxes	($169,391)	($34,035)	($132,396)	($338,341)	($17,740)	$0
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	$419,960	$84,380	($132,396)	$838,824	$43,981	$0
39							
40	Operating Income Before AFUDC	$419,960	$84,380	$328,240	$838,824	$43,981	($0)
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**$419,960**	**$84,380**	**$328,240**	**$838,824**	**$43,981**	**($0)**

Line No.	Description	CIP Incentive	CIP Carrying Charge	CPA Incentive	CPA	CCRC	Continuing Cost Recovery Riders
		(19)	(20)	(21)	(22)	(23)	(24)
1	Operating Revenue						
2	Sales by Rate Class			$2,089,215	($5,282,832)	$1,171,774	$75,415
3	Dual Fuel			$92,738	($238,418)		$3,005
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales			$2,181,953	($5,521,250)	$1,171,774	$78,419
8	Other Operating Revenue	($1,683,939)	($66,148)				($81,421,344)
9	Total Operating Revenue	($1,683,939)	($66,148)	$2,181,953	($5,521,250)	$1,171,774	($81,342,924)
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production						
14	Hydro Production						
15	Wind Production						
16	Solar Production						$97,484
17	Other Power Supply						
18	Purchased Power						($60,000)
19	Fuel						
20	Total Production						$37,484
21	Transmission						$33,963,434
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards						
25	Customer Service and Information						$435,999
26	Conservation Improvement Program						
27	Sales						
28	Administrative and General						
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses						$34,436,917
32	Depreciation Expense						$7,854,144
33	Amortization Expense						
34	Taxes Other Than Income Taxes						$19,135,412
35	Income Taxes	$483,998	$19,012	($627,137)	$1,586,918	($336,791)	$5,724,386
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	$483,998	$19,012	($627,137)	$1,586,918	($336,791)	$67,150,859
39							
40	Operating Income Before AFUDC	($1,199,942)	($47,136)	$1,554,816	($3,934,332)	$834,983	($14,192,065)
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**($1,199,942)**	**($47,136)**	**$1,554,816**	**($3,934,332)**	**$834,983**	**($14,192,065)**

Line No.	Description	Rate Case Expense	Revenue Budget Corrections	Excess ADIT	Boswell Inspection Costs	Interest Synchronization	Changes in Allocations due to Adjustments
		(25)	(26)	(27)	(28)	(29)	(30)
1	Operating Revenue						
2	Sales by Rate Class		$4,807	$9,355,979			
3	Dual Fuel			$156,330			
4	Intersystem Sales						
5	LP Demand Response						
6	Sales for Resale						
7	Total Revenue from Sales		$4,807	$9,512,309			
8	Other Operating Revenue						
9	Total Operating Revenue		$4,807	$9,512,309			
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production				($1,367,000)		
14	Hydro Production						
15	Wind Production						
16	Solar Production						
17	Other Power Supply						
18	Purchased Power						
19	Fuel						
20	Total Production				($1,367,000)		
21	Transmission						
22	Distribution						
23	Customer Accounting						
24	Customer Credit Cards						
25	Customer Service and Information						
26	Conservation Improvement Program						
27	Sales						
28	Administrative and General	($1,344,072)					
29	Charitable Contributions						
30	Interest on Customer Deposits						
31	Total Operation and Maintenance Expenses	($1,344,072)			($1,367,000)		
32	Depreciation Expense						
33	Amortization Expense						
34	Taxes Other Than Income Taxes						
35	Income Taxes	$386,313	($1,382)	($2,734,028)	$392,903	($2,319,870)	
36	Deferred Income Taxes						
37	Investment Tax Credit						
38	Total Operating Expenses Before AFUDC	($957,759)	($1,382)	($2,734,028)	($974,097)	($2,319,870)	
39							
40	Operating Income Before AFUDC	($957,759)	$3,425	$6,778,281	($974,097)	($2,319,870)	
41	Allowance for Funds Used During Construction						
42	**Total Operating Income**	**($957,759)**	**$3,425**	**$6,778,281**	**($974,097)**	**($2,319,870)**	

Line No.	Description	Total Adjustments	Proposed Interim Rates 2022
		(31)	(32)
1	Operating Revenue		
2	Sales by Rate Class	$7,414,358	$695,910,396
3	Dual Fuel	$13,655	$10,245,092
4	Intersystem Sales		$38,067,674
5	LP Demand Response		
6	Sales for Resale		$115,185,926
7	Total Revenue from Sales	$7,428,012	$859,409,088
8	Other Operating Revenue	($82,710,795)	$41,596,649
9	Total Operating Revenue	($75,282,783)	$901,005,737
10			
11	Operating Expenses Before AFUDC		
12	Operation and Maintenance Expenses		
13	Steam Production	($1,367,000)	($35,127,108)
14	Hydro Production		($5,146,274)
15	Wind Production		($17,535,442)
16	Solar Production	$97,484	
17	Other Power Supply		($1,813,088)
18	Purchased Power	($60,000)	($313,161,547)
19	Fuel		($94,465,966)
20	Total Production	($1,329,516)	($467,249,425)
21	Transmission	$33,963,434	($57,798,343)
22	Distribution	$5,000	($28,586,273)
23	Customer Accounting		($6,438,438)
24	Customer Credit Cards	$55,816	($294,188)
25	Customer Service and Information	$445,860	($1,531,514)
26	Conservation Improvement Program	$1,177,165	($10,714,344)
27	Sales	$103,016	($1,856)
28	Administrative and General	$5,975,281	($67,174,432)
29	Charitable Contributions	$610,757	($271,905)
30	Interest on Customer Deposits		($1,248,000)
31	Total Operation and Maintenance Expenses	$41,006,813	($641,308,719)
32	Depreciation Expense	$7,980,040	($149,593,464)
33	Amortization Expense	($557,430)	($7,864,938)
34	Taxes Other Than Income Taxes	$19,135,412	($41,733,954)
35	Income Taxes	($101,577)	($9,533,878)
36	Deferred Income Taxes		$43,703,802
37	Investment Tax Credit		$510,490
38	Total Operating Expenses Before AFUDC	$67,463,257	($805,820,661)
39			
40	Operating Income Before AFUDC	($7,819,526)	$95,185,076
41	Allowance for Funds Used During Construction		$2,942,167
42	**Total Operating Income**	**($7,819,526)**	**$98,127,243**

Line No.	Description	Calculation Note	Proposed Interim Rates 2022 Total Company	Proposed Interim Rates 2022 Minnesota Jurisdiction
		(1)	(2)	(3)
1	Average Rate Base		$2,347,057,389	$2,056,120,621
2	Requested Weighted Cost of Debt		0.01998	0.01998
3	Interest	Line 1 * Line 2	$46,887,165	$41,075,122
4	Interest in Unadjusted Test Year		$54,958,525	$47,914,687
5	Interest Deduction Adjustment	Line 4 - Line 3	$8,071,360	$6,839,566
6				
7	Minnesota State Income Tax Rate		9.80%	9.80%
8	State Tax Interest Adjustment	Line 5 * Line 7 * - 1	($790,993)	($670,277)
9				
10	Effective Federal Income Tax Rate		18.94%	18.94%
11	Federal Tax Interest Adjustment	Line 5 * Line 10 * - 1	($1,528,877)	($1,295,551)
12				
13	**Total Interest Synchronization Adjustment**	Line 8 + Line 11	**($2,319,870)**	**($1,965,828)**

Line No.	Description	Calculation Note	Minnesota Jurisdiction Unadjusted Test Year 2022	Minnesota Jurisdiction Proposed Interim Rates 2022
		(1)	(2)	(3)
1	Average Rate Base		$2,398,492,632	$2,056,120,621
2	Operating Income Before AFUDC		$87,931,775	$78,694,642
3	AFUDC		$2,485,807	$2,485,869
4	Operating Income	Line 2 + Line 3	$90,417,582	$81,180,511
5	Rate of Return	Line 4 / Line 1	3.7698%	3.9482%
6	Required Rate of Return		6.9752%	6.9752%
7	Required Operating Income	Line 1 * Line 6	$167,299,658	$143,418,526
8	Operating Income Deficiency	Line 7 - Line 4	$76,882,076	$62,238,015
9	Gross Revenue Conversion Factor		1.40335	1.40335
10	Revenue Deficiency	Line 8 * Line 9	$107,892,554	$87,341,793
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$606,231,184	$613,659,194
12	Required Percent Increase	Line 10 / Line 11	17.7973%	14.2329%

Line No.	Description	Minnesota Jurisdiction		
		Results of Most Recent Rate Case (E015/GR-16-664)	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)
1	Plant In Service			
2	Steam	$1,377,553,044	$1,363,731,716	($13,821,328)
3	Hydro	$161,747,996	$189,924,458	$28,176,462
4	Wind	$682,699,561	$701,161,540	$18,461,979
5	Solar			
6	Transmission	$606,702,164	$698,508,020	$91,805,856
7	Distribution	$555,361,755	$666,417,408	$111,055,653
8	General Plant	$173,233,680	$205,637,403	$32,403,723
9	Intangible Plant	$67,006,652	$60,731,625	($6,275,027)
10	Total Plant In Service	$3,624,304,852	$3,886,112,169	$261,807,317
11				
12	Accumulated Depreciation and Amortization			
13	Steam	($583,396,685)	($684,621,867)	($101,225,182)
14	Hydro	($22,350,269)	($40,803,571)	($18,453,302)
15	Wind	($77,974,321)	($174,165,052)	($96,190,731)
16	Solar			
17	Transmission	($197,328,141)	($243,569,856)	($46,241,715)
18	Distribution	($260,829,598)	($318,622,695)	($57,793,097)
19	General Plant	($85,720,751)	($95,766,359)	($10,045,608)
20	Intangible Plant	($43,727,842)	($35,514,304)	$8,213,538
21	Total Accumulated Depreciation and Amortization	($1,271,327,607)	($1,593,063,705)	($321,736,098)
22				
23	Net Plant Before CWIP			
24	Steam	$794,156,359	$679,109,849	($115,046,510)
25	Hydro	$139,397,727	$149,120,887	$9,723,160
26	Wind	$604,725,240	$526,996,487	($77,728,753)
27	Solar			
28	Transmission	$409,374,023	$454,938,164	$45,564,141
29	Distribution	$294,532,157	$347,794,713	$53,262,556
30	General Plant	$87,512,929	$109,871,044	$22,358,115
31	Intangible Plant	$23,278,810	$25,217,321	$1,938,511
32	Total Net Plant Before CWIP	$2,352,977,245	$2,293,048,464	($59,928,781)
33	Construction Work in Progress	$21,936,336	$35,783,807	$13,847,471
34	Utility Plant	$2,374,913,581	$2,328,832,271	($46,081,310)
35				
36	Working Capital			
37	Fuel Inventory	$37,891,203	$14,689,646	($23,201,557)
38	Materials and Supplies	$25,410,468	$24,599,288	($811,180)
39	Prepayments	$30,396,543	$24,230,206	($6,166,337)
40	Cash Working Capital	($26,950,177)	($39,366,227)	($12,416,050)
41	Total Working Capital	$66,748,037	$24,152,914	($42,595,123)
42				
43	Additions and Deductions			
44	Asset Retirement Obligation			
45	Electric Vehicle Program			
46	Workers Compensation Deposit	$74,492	$71,223	($3,269)
47	Unamortized WPPI Transmission Amortization	($2,150,893)	($425,308)	$1,725,585
48	Unamortized UMWI Transaction Cost	$1,425,067	$987,318	($437,749)
49	Unamortized Boswell 1 and 2		($4,893,264)	($4,893,264)
50	Customer Advances	($1,790,064)	($1,762,180)	$27,884
51	Customer Deposits	($240,131)		
52	Other Deferred Credits - Hibbard	($286,114)	($298,251)	($12,137)
53	Wind Performance Deposit	($125,867)	($131,883)	($6,016)
54	Accumulated Deferred Income Taxes	($389,645,990)	($290,412,218)	$99,233,772
55	Total Additions and Deductions	($392,739,500)	($296,864,563)	$95,634,806
56				
57	**Total Average Rate Base**	**$2,048,922,118**	**$2,056,120,621**	**$6,958,372**

General Description

The Company has identified those significant events affecting changes in the major categories of Rate Base since the last Order in Docket No. **E-015/GR-16-664**. This summary explains changes shown in Direct Schedule C-1 (IR).

Item	Description and Basis
Steam Production Plant	The decrease is primarily due to retiring Boswell Units 1 and 2 in 2018 and transferring the plant balance to a regulated asset reflecting continued cost recovery through 2022. This decrease was partially offset by regularly-scheduled, necessary, critical turbine refurbishments on Boswell Units 3 and 4, replacement of critical worn parts on Boswell Units 3 and 4, replacement of the hot reheat piping line on Boswell Unit 4, projects to reduce wastewater streams and Combustion Coal Residuals (CCR) at the Boswell facility, and on-going capital investment and upgrades to other steam generation units.
Hydro Production Plant	The increase is primarily due to on-going capital investment and upgrades to hydro generation units such as concrete and gate replacement projects.
Wind Production Plant	The increase is primarily due to on-going capital investment and upgrades to wind generation units such as blade and gearbox replacements.
Transmission Plant	The increase is primarily due to strategic capital investments related to the on-going transition of the Company's baseload coal generation fleet as well as on-going capital investments and upgrades to improve reliability and power quality.
Distribution Plant	The increase is primarily due to on-going capital investments and upgrades to improve reliability and power quality.
General Plant	The increase is primarily due to on-going capital investment.
Intangible Plant	The decrease is primarily due to retirements since the most recent rate case, partially offset by on-going capital investment, primarily software.

Item	Description and Basis
Accumulated Depreciation and Amortization	Depreciation and amortization reserves increased, except for intangible plant, primarily due to the additions of tangible plant, partially offset by retiring Boswell Units 1 and 2 in 2018 and transferring the accumulated depreciation balance to a regulated asset reflecting continued cost recovery through 2022. Intangible plant accumulated amortization reserves decreased primarily due to retirements since the most recent rate case, partially offset by the additions of intangible plant.
Construction Work In Progress	The increase is primarily due to changes in the level of capital investment from year to year.
Working Capital	Fuel inventory decreases are primarily due to bringing fuel inventory back to a normal level and the reduction in coal burn as a result of the retirement of Boswell Units 1 and 2. The last rate case had a high fuel inventory level as a result of building up fuel inventory before rail delivery rates increased. Prepayments decreased primarily due to amortization of the contract prepayment with Silver Bay Power.
Unamortized Boswell 1 and 2	The decrease is due to retiring Boswell Units 1 and 2 and transferring the plant balance and accumulated depreciation to a regulated asset in 2018 reflecting continued cost recovery through 2022. In 2022 the regulated asset for Boswell Units 1 and 2 is a credit balance so the adjustment reduces rate base.
Accumulated Deferred Income Taxes	The decrease is primarily due to book depreciation in excess of tax depreciation, and additional production tax credits earned.

Comparison of Proposed Interim Rates to Most Recent General Rate Case
Statement of Operating Income
Direct Schedule C-3 (IR)

Line No.	Description	Minnesota Jurisdiction: Results of Most Recent Rate Case (E015\FR-16-664)	Minnesota Jurisdiction: Proposed Interim Rates 2022	Minnesota Jurisdiction: Difference
		(1)	(2)	(3)
1	Operating Revenue			
2	Sales by Rate Class	$644,599,005	$603,414,102	($41,184,903)
3	Dual Fuel	$10,538,568	$10,245,092	($293,476)
4	Intersystem Sales	$6,482,677	$32,671,772	$26,189,095
5	LP Demand Response			
6	Sales for Resale	$126,505,800	$99,658,724	($26,847,076)
7	Total Revenue from Sales	$788,126,050	$745,989,689	($42,136,361)
8	Other Operating Revenue	$41,952,810	$34,497,318	($7,455,492)
9	Total Operating Revenue	$830,078,860	$780,487,008	($49,591,852)
10				
11	Operating Expenses Before AFUDC			
12	Operation and Maintenance Expenses			
13	Steam Production	($41,006,829)	($30,519,440)	$10,487,389
14	Hydro Production	($5,716,958)	($4,460,500)	$1,256,458
15	Wind Production	($13,766,390)	($15,417,511)	($1,651,121)
16	Solar Production			
17	Other Power Supply	$468,020	($1,594,103)	($2,062,123)
18	Purchased Power	($204,620,065)	($270,170,787)	($65,550,722)
19	Fuel	($122,233,712)	($80,955,983)	$41,277,729
20	Total Production	($386,875,934)	($403,118,324)	($16,242,390)
21	Transmission	($47,345,228)	($47,480,572)	($135,344)
22	Distribution	($23,697,619)	($27,110,481)	($3,412,862)
23	Customer Accounting	($6,362,302)	($6,385,512)	($23,210)
24	Customer Credit Cards	($350,000)	($294,188)	$55,812
25	Customer Service and Information	($2,746,697)	($1,515,636)	$1,231,061
26	Conservation Improvement Program	($10,447,625)	($10,714,344)	($266,719)
27	Sales	($40,958)	($1,856)	$39,102
28	Administrative and General	($48,386,941)	($59,529,378)	($11,142,437)
29	Charitable Contributions	($394,280)	($241,756)	$152,524
30	Interest on Customer Deposits	($1,071,000)	($1,248,000)	($177,000)
31	Total Operation and Maintenance Expenses	($527,718,584)	($557,640,048)	($29,921,464)
32	Depreciation Expense	($123,591,686)	($132,205,265)	($8,613,579)
33	Amortization Expense	($4,217,942)	($6,978,591)	($2,760,649)
34	Taxes Other Than Income Taxes	($42,278,734)	($37,219,906)	$5,058,828
35	Income Taxes	$1,213,049	($6,461,923)	($7,674,972)
36	Deferred Income Taxes	$8,516,506	$38,267,588	$29,751,082
37	Investment Tax Credit	$364,441	$445,778	$81,337
38	Total Operating Expenses Before AFUDC	($687,712,950)	($701,792,366)	($14,079,416)
39				
40	Operating Income Before AFUDC	$142,365,910	$78,694,642	($63,671,268)
41	Allowance for Funds Used During Construction	$2,367,898	$2,485,869	$117,971
42	**Total Operating Income**	**$144,733,808**	**$81,180,511**	**($63,553,297)**

General Description

Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the last Order in Docket No. E015/GR-16-664. This summary explains changes shown in Direct Schedule C-3 (IR).

Item	Description and Basis
Operating Revenue:	The comparison of revenue by rate class is based on final rate revenue in Docket No. E015/GR-16-664 (2016 Rate Order) as compared to the interim rate revenue in the present docket (2022 test year).
Sales by Class	The decrease in Sales by Class revenue from the 2016 Rate Order to the 2022 test year reflects a decline in load of approximately 18 percent, partially offset by recovery of higher fuel adjustment clause costs. The decrease in load reflects the impact of unfavorable market conditions that led to the closure or idling of businesses, including Blandin Paper Company's Paper Machine #5 in 2017 and Verso Corporation in 2020. Load loss due to energy efficiencies also reduced revenue. As part of the Company's 2019 rate case resolution effective July 1, 2020, higher firm energy rates were implemented along with margins on asset backed market sales flowing through the fuel adjustment clause.
Dual Fuel	No significant change.
Intersystem Sales	The increase in Intersystem Sales revenue from the 2016 Rate Order to the 2022 test year is primarily due to more sales to Silver Bay Power Corporation. In 2019, Silver Bay Power ceased self-generation.
Sales for Resale	The decrease in Sales for Resale revenue from the 2016 Rate Order to the 2022 test year is primarily due to lower wholesale power sales as a 100 MW Large Market Contract expired on April 30, 2020. This decrease is partially offset by an increase in revenue from Minnkota Power Cooperative, Inc. (Minnkota Power) due to the resale of approximately 32 percent in 2022 (approximately 28 percent in 2016 Rate Order) of Minnesota Power's 50 percent output entitlement from Square Butte Electric Cooperative (Square Butte), under a power sales agreement with Minnkota Power which commenced June 1, 2014. "See "Purchased Power".
Other Operating Revenue	Other Operating Revenue decreased from the 2016 Rate Order to the 2022 test year primarily due to the absence of revenue in the 2022 test year from steam sales due to the loss of a large power customer and coals sales due to the conversion of a Company facility to gas.
Operating Expenses:	
Steam Production	Steam Production expense decreased from the 2016 Rate Order to the 2022 test year primarily due to the retirement of Units 1 and 2 at the Boswell Energy Center in December 2018, and lower labor and related benefit expenses at other units or facilities. These decreases were partially offset by an adjustment reducing Steam Production expense in the most recent general rate case.
Hydro Production	Hydro Production expense decreased from the 2016 Rate Order to the 2022 test year primarily due to lower labor and related benefit expenses. These decreases were partially offset by an adjustment reducing Hydro Production expense in the most recent general rate case.

General Description

Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the last Order in Docket No. E015/GR-16-664. This summary explains changes shown in Direct Schedule C-3 (IR).

Item	Description and Basis
Wind Production	Wind Production expense increased from the 2016 Rate Order to the 2022 test year primarily due to escalation factors in the long-term service agreements for the Bison Wind Energy Center.
Other Power Supply	Other Power Supply expense increased from the 2016 Rate Order to the 2022 test year primarily due to an adjustment reducing Other Power Supply expense in the most recent general rate case.
Purchased Power	Purchased Power expense increased from 2020 to the 2022 test year primarily due to additional long-term power purchase agreements, which include 250 MW of capacity and energy and 133 MW of energy only from Manitoba Hydro-Electric Board as well as 250 MW of wind generation from the Nobles 2 wind facility. These purchases and additional MISO market purchases are necessary to meet load requirements following the retirement of Boswell Energy Center Unit 1 and 2 at the end of 2018 and Boswell Energy Center Unit 3 moving to economic dispatch in July 2021. Minnesota Power is selling approximately 32 percent in 2022 (approximately 28 percent in 2016 Rate Order) of its 50 percent output entitlement from Square Butte to Minnkota Power, under a power sales agreement with Minnkota Power which commenced June 1, 2014. Minnkota Power's net entitlement increases and Minnesota Power's net entitlement decreases until Minnesota Power's share is eliminated at the end of 2025. See "Sales for Resale".
Fuel	Fuel expense decreased from the 2016 Rate Order to the 2022 test year primarily due to the retirement of Boswell Energy Center Units 1 and 2 at the end of 2018.
Transmission	No significant change.
Distribution	Distribution expenses increased from the 2016 Rate Order to the 2022 test year primarily due to higher vegetation management costs.
Customer Accounting	No significant change.
Customer Credit Cards	No significant change.
Customer Service and Information	Customer Service and Information expense decreased from the 2016 Rate Order to the 2022 test year primarily due to lower labor and benefits as well as an adjustment in the 2022 test year to remove SolarSense expenses that will remain in a continuing cost recovery rider, and lower labor and related benefit expenses.
Conservation Improvement Program	No significant change.
Sales	No significant change.
Administrative and General	Administrative and General expenses increased from the 2016 Rate Order to the 2022

General Description

Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the last Order in Docket No. E015/GR-16-664. This summary explains changes shown in Direct Schedule C-3 (IR).

Item	Description and Basis
	test year primarily due to adjustments reducing Administrative and General expense in the most recent general rate case, higher expense for insurance premiums, higher information technology hardware and software costs, and the absence of the deferred fuel adjustment clause. These increases were partially offset by lower benefit expenses.
Charitable Contributions	Charitable Contributions are based on an average of the three most recently completed years. The decrease is primarily due to fewer charitable contributions in the three most recently completed years preceding the 2022 test year compared to those preceding the last general rate case.
Interest on Customer Deposits	Primarily relates to weekly billings to Large Power customers which are reduced by an interest component that is included as a Company expense. Interest calculation is based on billings to customers which will vary from year to year.
Depreciation Expense	Depreciation Expense increased from the 2016 Rate Order to the 2022 test year primarily due to higher plant in-service. This increase is partially offset by the reclassification of Units 1 and 2 at the Boswell Energy Center as regulatory assets in December 2018. See "Amortization Expense".
Amortization Expense	Amortization expense increased from the 2016 Rate Order to the 2022 test year primarily due to the retirement of Units 1 and 2 at the Boswell Energy Center in December 2018, which are now classified as a regulatory asset with associated amortization for 2022 being amortized over three years. These units were included in depreciation expense in the most recent general rate case. See "Depreciation Expense". Higher intangible plant in-service also contributed to this increase.
Taxes Other Than Income Taxes	Taxes Other Than Income Taxes decreased from the 2016 Rate Order to the 2022 test year primarily due to an adjustment in the 2022 test year to remove taxes other than income taxes that will remain in a continuing cost recovery rider.
Income Taxes / Deferred Income Taxes	Income Taxes reflect lower pretax income and higher production tax credits in the 2022 test year.
Investment Tax Credit	No significant change.
Allowance for Funds Used During Construction	Allowance for Funds Used During Construction increased from the 2016 Rate Order to the 2022 test year primarily due to changes in the level of capital investment from year to year.

Line No.	Description	Calculation Note	Minnesota Jurisdiction		
			Results of Most Recent Rate Case (E015/GR-16-664)	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,048,922,118	$2,056,120,621	$7,198,503
2	Operating Income Before AFUDC		$142,365,910	$78,694,642	($63,671,268)
3	AFUDC		$2,367,898	$2,485,869	$117,971
4	Operating Income	Line 2 + Line 3	$144,733,808	$81,180,511	($63,553,297)
5	Rate of Return	Line 4 / Line 1	7.0639%	3.9482%	(882.8682%)
6	Required Rate of Return		7.0639%	6.9752%	(0.0887%)
7	Required Operating Income	Line 1 * Line 6	$144,733,808	$143,418,526	($6,385)
8	Operating Income Deficiency	Line 7 - Line 4		$62,238,015	$63,546,912
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9		$87,341,793	
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$606,231,184	$613,659,194	$7,428,010
12	Required Percent Increase	Line 10 / Line 11		14.2329%	

Minnesota Power
Comparison of Most Recently Approved
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction
(Thousands of Dollars)

I. Capital structure and rate of return calculation approved by the commission in Minnesota Power's most recent general rate case (Docket No. E-015/GR-16-664)

	Amount	% of Total	Component Cost	Weighted Cost
Long Term Debt	$1,228,550	46.1892%	4.5170%	2.0864%
Common Equity	$1,431,272	53.8108%	9.2500%	4.9775%
Total Capitalization	$2,659,822	100.0000%		7.0639%

II. Capital structure and rate of return calculation for proposed interim rates 2022

	Projected Amount	Projected % of Total	Requested % of Total	Component Cost	Weighted Cost
Long Term Debt	$1,312,084	45.8838%	46.1892%	4.3250%	1.9977%
Common Equity	$1,547,493	54.1162%	53.8108%	9.2500%	4.9775%
Total Capitalization	$2,859,577	100.0000%	100.0000%		6.9752%

III. Amount of changes between I and II

	Most Recent General Rate Case Filing	Proposed Interim Filing	Change
Long Term Debt	$1,228,550	$1,312,084	$83,534
Common Equity	$1,431,272	$1,547,493	$116,221
Total Capitalization	$2,659,822	$2,859,577	$199,755

Minnesota Power
Comparison of Most Recently Approved
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction

I. The long term debt portion of the capital structure proposed in this rate case increased by approximately $83.5 million compared to the last rate case filing in Docket No. E-015/GR-16-664. The component cost of long term debt decreased from 4.5170% in the 2016 rate filing to 4.3250% in the current rate filing.

Common equity increased by $116.2 million due to actual and projected issuances of common stock and increases in retained earnings.

				Operating Revenues		Increase	
	Customer Classes	**Customers**	**MWh**	**Present**	**Interim**	**$**	**%**
1	Residential	114,153	946,536	$ 111,948,172	$ 127,878,397	$ 15,930,225	14.23%
2	General Service	21,248	658,315	$ 76,999,163	$ 87,956,144	$ 10,956,981	14.23%
3	Large Light & Power	442	1,217,232	$ 107,584,315	$ 122,893,563	$ 15,309,248	14.23%
4	Large Power	7	4,339,016	$ 303,074,818	$ 346,202,364	$ 43,127,547	14.23%
5	Lighting	5,206	13,975	$ 3,807,678	$ 4,349,511	$ 541,833	14.23%
6	Subtotal by Customer Class	141,056	7,175,074	$ 603,414,146	$ 689,279,979	$ 85,865,833	14.23%
	Dual Fuel (Interruptible)						
7	Dual Fuel - Residential	7,320	88,991	$ 8,260,534	$ 9,436,008	$ 1,175,474	14.23%
8	Dual Fuel - Commercial/Industrial	510	22,380	$ 1,984,546	$ 2,266,946	$ 282,401	14.23%
9	Subtotal Dual Fuel	7,830	111,371	$ 10,245,079	$ 11,702,954	$ 1,457,875	14.23%
10	**Total Sales of Electricity**	**148,886**	**7,286,445**	**$ 613,659,226**	**$ 700,982,933**	**$ 87,323,708**	**14.23%**
11	Large Power (Other)		872,711	$ 34,716,421	$ 34,716,421	$ -	0.00%
12	**Total Sales of Electricity (incl. LP - Other Energy)**	**148,886**	**8,159,156**	**648,375,646**	**735,699,354**	**87,323,708**	**13.47%**
	Adjustments for Riders						
	Retail SEA			$ (210,118)	$ (210,118)	$ -	0.00%
	Conservation Program Adjustment			$ 5,521,250	$ 5,521,250	$ -	0.00%
	CCRC			$ (1,171,774)	$ (1,171,774)	$ -	0.00%
	Transmission Adjustment			$ 26,361,634	$ 26,361,634	$ -	0.00%
	Renewable Adjustment			$ 712,921	$ 712,921	$ -	0.00%
	SRRR			$ 4,933,436	$ 4,933,436	$ -	0.00%
	SRRR Exempt			$ 219,034	$ 219,034	$ -	0.00%
	Community Solar Garden - Customer Charge			$ 124,397	$ 124,397	$ -	0.00%
	Community Solar Garden - Energy Charge			$ 7,306	$ 7,306	$ -	0.00%
	CARE Surcharge			$ 1,908,936	$ 1,908,936	$ -	0.00%
	Subtotal Revenue Adjustments			**$ 38,407,023**	**$ 38,407,023**	**$ -**	**0.00%**
	Total E-Schedule Revenue			**$ 686,782,669**	**$ 774,106,377**	**$ 87,323,708**	**12.71%**

Line No.	Description	Minnesota Jurisdiction		
		Most Recent Fiscal Year 2020	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)
1	Plant In Service			
2	Steam	$1,372,594,645	$1,363,731,716	($8,862,929)
3	Hydro	$182,188,690	$189,924,458	$7,735,768
4	Wind	$700,492,422	$701,161,540	$669,118
5	Solar	$176,617		($176,617)
6	Transmission	$800,522,886	$698,508,020	($102,014,866)
7	Distribution	$607,523,264	$666,417,408	$58,894,144
8	General Plant	$204,819,590	$205,637,403	$817,812
9	Intangible Plant	$49,851,559	$60,731,625	$10,880,066
10	Total Plant In Service	$3,918,169,674	$3,886,112,169	($32,057,504)
11				
12	Accumulated Depreciation and Amortization			
13	Steam	($596,499,887)	($684,621,867)	($88,121,981)
14	Hydro	($46,176,515)	($40,803,571)	$5,372,944
15	Wind	($137,086,516)	($174,165,052)	($37,078,537)
16	Solar	($22,055)		$22,055
17	Transmission	($210,272,500)	($243,569,856)	($33,297,357)
18	Distribution	($253,731,870)	($318,622,695)	($64,890,825)
19	General Plant	($106,626,005)	($95,766,359)	$10,859,646
20	Intangible Plant	($33,253,667)	($35,514,304)	($2,260,637)
21	Total Accumulated Depreciation and Amortization	($1,383,669,013)	($1,593,063,705)	($209,394,692)
22				
23	Net Plant Before CWIP			
24	Steam	$776,094,758	$679,109,849	($96,984,910)
25	Hydro	$136,012,175	$149,120,887	$13,108,712
26	Wind	$563,405,906	$526,996,487	($36,409,419)
27	Solar	$154,563		($154,563)
28	Transmission	$590,250,386	$454,938,164	($135,312,222)
29	Distribution	$353,791,395	$347,794,713	($5,996,682)
30	General Plant	$98,193,586	$109,871,044	$11,677,458
31	Intangible Plant	$16,597,892	$25,217,321	$8,619,428
32	Total Net Plant Before CWIP	$2,534,500,660	$2,293,048,464	($241,452,196)
33	Construction Work in Progress	$166,326,258	$35,783,807	($130,542,452)
34	Utility Plant	$2,700,826,919	$2,328,832,271	($371,994,647)
35				
36	Working Capital			
37	Fuel Inventory	$23,732,560	$14,689,646	($9,042,914)
38	Materials and Supplies	$22,299,871	$24,599,288	$2,299,417
39	Prepayments	$101,002,126	$24,230,206	($76,771,920)
40	Cash Working Capital	($27,960,555)	($39,366,227)	($11,405,673)
41	Total Working Capital	$119,074,002	$24,152,914	($94,921,089)
42				
43	Additions and Deductions			
44	Asset Retirement Obligation	($82,644,836)		$82,644,836
45	Electric Vehicle Program			
46	Workers Compensation Deposit	$66,812	$71,223	$4,411
47	Unamortized WPPI Transmission Amortization	($1,122,621)	($425,308)	$697,313
48	Unamortized UMWI Transaction Cost	$1,172,043	$987,318	($184,725)
49	Unamortized Boswell 1 and 2		($4,893,264)	($4,893,264)
50	Customer Advances	($2,057,641)	($1,762,180)	$295,461
51	Other Deferred Credits - Hibbard	($294,733)	($298,251)	($3,518)
52	Wind Performance Deposit	($130,328)	($131,883)	($1,556)
53	Accumulated Deferred Income Taxes	($367,408,407)	($290,412,218)	$76,996,189
54	Total Additions and Deductions	($452,419,711)	($296,864,563)	$155,555,147
55				
56	**Total Average Rate Base**	**$2,367,481,210**	**$2,056,120,621**	**($311,360,589)**

General Description

The Company has identified those significant events affecting changes in the major categories of Rate Base since the most recent fiscal year 2020 (unadjusted)**.** This summary explains changes shown in Direct Schedule D-1 (IR).

Item	Description and Basis
Steam Production Plant	The decrease is primarily due to adjustments in the 2022 test year for plant in-service, partially offset by regularly-scheduled, necessary, critical turbine refurbishments, replacement of the hot reheat piping line, and replacement of critical worn parts on Boswell Unit 4, projects to reduce wastewater streams and Combustion Coal Residuals (CCR) at the Boswell facility, and on-going capital investment and upgrades to other steam generation units.
Hydro Production Plant	The increase is due, primarily, to on- going capital investment and upgrades to hydro generation units such as concrete and gate replacement projects.
Wind Production Plant	The increase is due, primarily, to on-going capital investment and upgrades to wind generation units such as blade and gearbox replacements, partially offset by adjustments in the 2022 test year for plant in-service.
Transmission Plant	The decrease is due, primarily, to adjustments in the 2022 test year for plant in-service recovered through the Transmission Cost Recovery Rider, specifically the Great Northern Transmission Line. This decrease is partially offset by strategic capital investments related to the on-going transition of the Company’s baseload coal generation fleet as well as on-going capital investments and upgrades to improve reliability and power quality.
Distribution Plant	The increase is primarily due to on-going capital investments and upgrades to improve reliability and power quality, partially offset by adjustments in the 2022 test year for plant in-service.
General Plant	The increase is primarily due to on-going capital investment, partially offset by adjustments in the 2022 test year for plant in-service.

Item	Description and Basis
Intangible Plant	The increase is primarily due to on-going capital investment, primarily software.
Accumulated Depreciation and Amortization	Depreciation and Amortization reserves, for all except hydro production plant, general plant, and solar plant increased primarily due to the additions of tangible and intangible plant. There are also adjustments in the 2022 test year for accumulated depreciation and amortization that contributed to these increases and decreases.
Construction Work In Progress (CWIP)	The decrease is primarily due to changes in the level of capital investment from year to year and the adjustment for the removal of the Great Northern Transmission Line in the 2022 test year.
Working Capital	Fuel inventory decreases are primarily due to the continuation of bringing fuel inventory back to a normal target inventory level. Materials and supplies increases are primarily due to an adjustment in the 2022 test year for the DC line addition. Prepayments decreases are primarily due to adjustments in the 2022 interim test year to remove the prepaid pension asset and the prepaid OPEB asset.
Asset Retirement Obligations	There is an adjustment in the 2022 test year to remove asset retirement obligations.
Unamortized Boswell 1 and 2	The decrease is due to retiring Boswell Units 1 and 2 and transferring the plant balance and accumulated depreciation to a regulated asset in 2018 reflecting continued cost recovery through 2022. In 2022 the regulated asset for Boswell Units 1 and 2 is a credit balance so the adjustment reduces rate base.
Accumulated Deferred Income Taxes	The decrease is primarily due to book depreciation in excess of tax depreciation, and additional production tax credits earned.

Line No.	Description	Minnesota Jurisdiction		
		Most Recent Fiscal Year 2020	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)
1	Operating Revenue			
2	Sales by Rate Class	$564,431,846	$603,414,102	$38,982,256
3	Dual Fuel	$8,568,159	$10,245,092	$1,676,933
4	Intersystem Sales	$26,691,924	$32,671,772	$5,979,848
5	LP Demand Response			
6	Sales for Resale	$118,383,459	$99,658,724	($18,724,735)
7	Total Revenue from Sales	$718,075,387	$745,989,689	$27,914,302
8	Other Operating Revenue	$104,108,803	$34,497,318	($69,611,485)
9	Total Operating Revenue	$822,184,190	$780,487,008	($41,697,183)
10				
11	Operating Expenses Before AFUDC			
12	Operation and Maintenance Expenses			
13	Steam Production	($26,505,367)	($30,519,440)	($4,014,072)
14	Hydro Production	($3,873,795)	($4,460,500)	($586,705)
15	Wind Production	($14,145,944)	($15,417,511)	($1,271,567)
16	Solar Production	($62,735)		$62,735
17	Other Power Supply	($1,058,022)	($1,594,103)	($536,081)
18	Purchased Power	($234,885,498)	($270,170,787)	($35,285,289)
19	Fuel	($70,110,762)	($80,955,983)	($10,845,221)
20	Total Production	($350,642,124)	($403,118,324)	($52,476,200)
21	Transmission	($72,290,932)	($47,480,572)	$24,810,360
22	Distribution	($19,000,543)	($27,110,481)	($8,109,938)
23	Customer Accounting	($5,994,508)	($6,385,512)	($391,004)
24	Customer Credit Cards	($329,706)	($294,188)	$35,518
25	Customer Service and Information	($2,177,767)	($1,515,636)	$662,131
26	Conservation Improvement Program	($4,050,231)	($10,714,344)	($6,664,113)
27	Sales	($26,135)	($1,856)	$24,279
28	Administrative and General	($59,914,274)	($59,529,378)	$384,896
29	Charitable Contributions	($856,297)	($241,756)	$614,542
30	Interest on Customer Deposits	($1,363,208)	($1,248,000)	$115,208
31	Total Operation and Maintenance Expenses	($516,645,725)	($557,640,048)	($40,994,323)
32	Depreciation Expense	($128,781,088)	($132,205,265)	($3,424,177)
33	Amortization Expense	($5,465,232)	($6,978,591)	($1,513,359)
34	Taxes Other Than Income Taxes	($41,775,094)	($37,219,906)	$4,555,189
35	Income Taxes	($6,840,590)	($6,461,923)	$378,667
36	Deferred Income Taxes	$26,103,500	$38,267,588	$12,164,088
37	Investment Tax Credit	$458,000	$445,778	($12,222)
38	Total Operating Expenses Before AFUDC	($672,946,228)	($701,792,366)	($28,846,138)
39				
40	Operating Income Before AFUDC	$149,237,962	$78,694,642	($70,543,320)
41	Allowance for Funds Used During Construction	$1,695,637	$2,485,869	$790,232
42	**Total Operating Income**	**$150,933,600**	**$81,180,511**	**($69,753,089)**

General Description

Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the most recent fiscal year 2020. This summary explains changes shown in Direct Schedule D-3 (IR).

Item	Description and Basis
Operating Revenue:	The comparison of revenue by rate class is based on 2020 rate revenue as compared to the interim rate revenue in the present docket (2022 test year).
Sales by Class	The increase in Sales by Class revenue from 2020 to the 2022 test year reflects an increase in load of approximately 2 percent, partially offset by recovery of higher fuel adjustment clause costs. In 2020, sales were impacted by the COVID-19 pandemic.
Dual Fuel	The increase in Dual Fuel revenue from 2020 to the 2022 test year reflects an increase in load of approximately 6 percent, partially offset by recovery of higher fuel adjustment clause costs.
Intersystem Sales	The increase in Intersystem revenue from 2020 to the 2022 test year is primarily due to more sales to Silver Bay Power Corporation. In 2020, Silver Bay Power was idled for a portion of the year due to the COVID-19 pandemic.
Sales for Resale	The decrease in Sales for Resale revenue from 2020 to the 2022 test year reflects lower wholesale power sales as a 100 MW Large Market Contract expired on April 30, 2020, and the Company made additional bilateral market sales in 2020 as large power customer load was reduced due to the COVID-19 pandemic. This decrease is partially offset by an increase in revenue from Minnkota Power Cooperative, Inc. (Minnkota Power) due to the resale of approximately 32 percent in 2022 (approximately 28 percent in 2020) of Minnesota Power's 50 percent output entitlement from Square Butte Electric Cooperative (Square Butte), under a power sales agreement with Minnkota Power which commenced June 1, 2014. "See "Purchased Power".
Other Operating Revenue	Revenue decreased from 2020 to the 2022 test year primarily due to the exclusion of revenue related to the riders for Transmission Cost Recovery and Renewable Resources-Solar Factor Adjustment in the 2022 test year.
Operating Expenses:	
Steam Production	Steam Production expense increased from 2020 to the 2022 test year primarily due to higher generation maintenance expense at the Boswell Energy Center. The amount budgeted in a given year for generation maintenance fluctuates, in part, based on the length and scope of planned outages each year at the Company's generation units according to the long-term outage plan. In addition, 2020 was impacted by the COVID-19 pandemic resulting in the certain outage work being deferred to 2021.
Hydro Production	Hydro production expense increased from 2020 to the 2022 test year primarily due to higher contract and professional services.
Wind Production	Wind Production expense increased from 2020 to the 2022 test year primarily due to escalation factors in the long-term service agreements for the Bison Wind Energy Center and higher labor and benefit expenses.

General Description

Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the most recent fiscal year 2020. This summary explains changes shown in Direct Schedule D-3 (IR).

Item	Description and Basis
Solar Production	Solar Production expense decreased from 2020 to the 2022 test year due to an adjustment in the 2022 test year to remove expenses that will remain in a continuing cost recovery rider.
Other Power Supply	Other Power Supply expense increased from 2020 to the 2022 test year primarily due to 2020 including a credit for a prior period charge in 2019.
Purchased Power	Purchased Power expense increased from 2020 to the 2022 test year primarily due to additional long-term power purchase agreements. The 2022 test year includes a full-year of the 250 MW of capacity and energy and 133 MW of energy only from Manitoba Hydro-Electric Board as well as a full-year of the 250 MW of wind generation from the Nobles 2 wind facility. These purchases and additional MISO market purchases are necessary to meet load requirements following Boswell Energy Center Unit 3 moving to economic dispatch in July 2021. Minnesota Power is selling approximately 32 percent in 2022 (approximately 28 percent in 2020) of its 50 percent output entitlement from Square Butte to Minnkota Power, under a power sales agreement with Minnkota Power which commenced June 1, 2014. Minnkota Power's net entitlement increases and Minnesota Power's net entitlement decreases until Minnesota Power's share is eliminated at the end of 2025. See "Sales for Resale".
Fuel	Fuel expense increased from 2020 to the 2022 test year as both rail transportation and coal commodity costs have escalated between the years 2020 and 2022.
Transmission	Transmission expense decreased from 2020 to the 2022 test year primarily due to an adjustment in the 2022 test year to remove expenses that will remain in a continuing cost recovery rider.
Distribution	Distribution expenses increased from 2020 to the 2022 test year primarily due to higher meter expense, vegetation management costs, and storm response expense.
Customer Accounting	No significant change.
Customer Credit Cards	No significant change.
Customer Service and Information	Customer Service and Information expense decreased from 2020 to the 2022 test year primarily due to an adjustment in the 2022 test year to remove expenses that will remain in a continuing cost recovery rider.
Conservation Improvement Program	Conservation Improvement Program expenses increased due to higher expected spending on conservation programs. The 2022 test year expense is based on the proposed annual CIP budget filed with the Minnesota Department of Commerce.
Sales	Sales expense decreased from 2020 to the 2022 test year primarily due to an adjustment in the 2022 test year to remove advertising expenses that are not recoverable.

General Description

Minnesota Power ("Company") has identified those significant events affecting changes in the major categories of Operating Income since the most recent fiscal year 2020. This summary explains changes shown in Direct Schedule D-3 (IR).

Item	Description and Basis
Administrative and General	Administrative and General expenses decreased primarily due to an adjustment in the 2022 test year to reduce incentive compensation based on prior practice and orders in previous rate cases. This decrease is mostly offset by higher insurance expense, hardware and software costs, and employee expenses as 2020 was impacted by the COVID-19 pandemic.
Charitable Contributions	Charitable Contributions are based on an average of the three most recently completed years for 2022 interim rates. The decrease is primarily due to fewer charitable contributions in the three most recently completed years preceding the 2022 test year compared to 2020 as well as an adjustment to remove 50 percent of charitable deductions in interim rates.
Interest on Customer Deposits	Primarily relates to weekly billings to Large Power customers which are reduced by an interest component that is included as a Company expense. Interest calculation is based on billings to customers which will vary from year to year.
Depreciation Expense	Depreciation Expense increased from 2020 to the 2022 test year primarily due to higher plant in-service if adjustments in the 2022 test year for plant in-service are ignored, partially offset by adjustments in the 2022 test year for depreciation expense.
Amortization Expense	Amortization expense increased from 2020 to the 2022 test year primarily due to higher intangible plant in-service, partially offset by 2022 amortization expense for the Boswell Energy Center Units 1 and 2 regulated asset being spread over three years in proposed interim rates.
Taxes Other Than Income Taxes	Taxes Other Than Income Taxes decreased from 2020 to the 2022 test year primarily due to an adjustment in the 2022 test year to remove taxes other than income taxes that will remain in a continuing cost recovery rider.
Income Taxes / Deferred Income Taxes	Income Taxes reflect lower pre-tax income and no net operating loss carryforward usage in the 2022 test year.
Investment Tax Credit	No significant change.
Allowance for Funds Used During Construction	Allowance for Funds Used During Construction increased from 2020 to the 2022 test year primarily due to changes in the level of capital investment from year to year.

Line No.	Line	Calculation Note	Minnesota Jurisdiction		
			Most Recent Fiscal Year 2020	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,367,481,210	$2,056,120,621	($311,360,589)
2	Operating Income Before AFUDC		$149,237,962	$78,694,642	($70,543,320)
3	AFUDC		$1,695,637	$2,485,869	$790,232
4	Operating Income	Line 2 + Line 3	$150,933,600	$81,180,511	($69,753,089)
5	Rate of Return	Line 4 / Line 1	6.3753%	3.9482%	22.4027%
6	Required Rate of Return		7.0158%	6.9752%	(0.0406%)
7	Required Operating Income	Line 1 * Line 6	$166,097,747	$143,418,526	$126,412
8	Operating Income Deficiency	Line 7 - Line 4	$15,164,147	$62,238,015	$69,879,501
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9	$21,280,624	$87,341,793	
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$573,000,004	$613,659,194	$40,659,190
12	Required Percent Increase	Line 10 / Line 11	3.7139%	14.2329%	

Minnesota Power
Comparison of Most Recent Fiscal Year
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction

(Thousands of Dollars)

I. Capital structure and rate of return calculation for most recent fiscal year 2020

	Amount	% of Total	Component Cost	Weighted Cost
Long Term Debt	$1,294,465	46.4013%	4.4349%	2.0579%
Common Equity	$1,495,252	53.5987%	8.0550%	4.3174%
Total Capitalization	$2,789,717	100.0000%		6.3753%

II. Capital structure and rate of return calculation for proposed interim rates 2022

	Projected Amount	Projected % of Total	Requested % of Total	Component Cost	Weighted Cost
Long Term Debt	$1,312,084	45.8838%	46.1892%	4.3250%	1.9977%
Common Equity	$1,547,493	54.1162%	53.8108%	9.2500%	4.9775%
Total Capitalization	$2,859,577	100.0000%	100.0000%		6.9752%

III. Amount of changes between I and II

	Most Recent Fiscal Year	Proposed Interim Filing	Change
Long Term Debt	$1,294,465	$1,312,084	$17,619
Common Equity	$1,495,252	$1,547,493	$52,241
Total Capitalization	$2,789,717	$2,859,577	$69,860

Minnesota Power
Comparison of Most Recent Fiscal Year
Capital Structure and Rate of Return Calculations
Minnesota Jurisdiction

I. The long term debt portion of the capital structure proposed in this rate case increased by approximately $17.6 million compared to the most recent fiscal year (2020). The component cost of long term debt decreased from 4.4349% in the 2020 fiscal year to 4.3250% in the current rate filing.

Common equity increased by $52.2 million due to actual and projected issuances of common stock and increases in retained earnings.

Line No.	Description	Minnesota Jurisdiction		
		Results of Most Recent Rate Case (E015/GR-16-664)	Proposed Test Year 2022	Difference
		(1)	(2)	(3)
1	Plant In Service			
2	Steam	$1,377,553,044	$1,363,731,716	($13,821,328)
3	Hydro	$161,747,996	$189,923,705	$28,175,709
4	Wind	$682,699,561	$701,161,540	$18,461,979
5	Solar			
6	Transmission	$606,702,164	$698,508,020	$91,805,856
7	Distribution	$555,361,755	$666,417,408	$111,055,653
8	General Plant	$173,233,680	$205,636,111	$32,402,431
9	Intangible Plant	$67,006,652	$60,731,244	($6,275,408)
10	Total Plant In Service	$3,624,304,852	$3,886,109,743	$261,804,891
11				
12	Accumulated Depreciation and Amortization			
13	Steam	($583,396,685)	($684,621,867)	($101,225,182)
14	Hydro	($22,350,269)	($40,803,409)	($18,453,140)
15	Wind	($77,974,321)	($174,165,052)	($96,190,731)
16	Solar			
17	Transmission	($197,328,141)	($243,569,856)	($46,241,715)
18	Distribution	($260,829,598)	($318,622,695)	($57,793,097)
19	General Plant	($85,720,751)	($95,765,757)	($10,045,006)
20	Intangible Plant	($43,727,842)	($35,514,081)	$8,213,761
21	Total Accumulated Depreciation and Amortization	($1,271,327,607)	($1,593,062,718)	($321,735,111)
22				
23	Net Plant Before CWIP			
24	Steam	$794,156,359	$679,109,849	($115,046,510)
25	Hydro	$139,397,727	$149,120,296	$9,722,569
26	Wind	$604,725,240	$526,996,487	($77,728,753)
27	Solar			
28	Transmission	$409,374,023	$454,938,164	$45,564,141
29	Distribution	$294,532,157	$347,794,713	$53,262,556
30	General Plant	$87,512,929	$109,870,354	$22,357,425
31	Intangible Plant	$23,278,810	$25,217,162	$1,938,352
32	Total Net Plant Before CWIP	$2,352,977,245	$2,293,047,025	($59,930,220)
33	Construction Work in Progress	$21,936,336	$35,783,783	$13,847,447
34	Utility Plant	$2,374,913,581	$2,328,830,808	($46,082,773)
35				
36	Working Capital			
37	Fuel Inventory	$37,891,203	$14,689,205	($23,201,998)
38	Materials and Supplies	$25,410,468	$24,599,288	($811,180)
39	Prepayments	$30,396,543	$115,202,736	$84,806,193
40	Cash Working Capital	($26,950,177)	($39,778,461)	($12,828,284)
41	Total Working Capital	$66,748,037	$114,712,769	$47,964,732
42				
43	Additions and Deductions			
44	Asset Retirement Obligation			
45	Electric Vehicle Program			
46	Workers Compensation Deposit	$74,492	$71,222	($3,270)
47	Unamortized WPPI Transmission Amortization	($2,150,893)	($425,308)	$1,725,585
48	Unamortized UMWI Transaction Cost	$1,425,067	$987,318	($437,749)
49	Unamortized Boswell 1 and 2		($4,893,264)	($4,893,264)
50	Customer Advances	($1,790,064)	($1,762,180)	$27,884
51	Customer Deposits	($240,131)		
52	Other Deferred Credits - Hibbard	($286,114)	($298,251)	($12,137)
53	Wind Performance Deposit	($125,867)	($131,883)	($6,016)
54	Accumulated Deferred Income Taxes	($389,645,990)	($324,059,370)	$65,586,620
55	Total Additions and Deductions	($392,739,500)	($330,511,716)	$61,987,653
56				
57	**Total Average Rate Base**	**$2,048,922,118**	**$2,113,031,861**	**$63,869,612**

General Description

The Company has identified those significant events affecting changes in the major categories of Rate Base since the last Order in Docket No. E-015/GR-16-664 (2016 Rate Case). This summary explains changes shown in Direct Schedule E-1 (IR).

Item	Description and Basis
Steam Production Plant	The decrease is primarily due to retiring Boswell Units 1 and 2 in 2018 and transferring the plant balance to a regulated asset reflecting continued cost recovery through 2022. This decrease was partially offset by regularly-scheduled, necessary, critical turbine refurbishments on Boswell Units 3 and 4, replacement of critical worn parts on Boswell Units 3 and 4, replacement of the hot reheat piping line on Boswell Unit 4, projects to reduce wastewater streams and Combustion Coal Residuals (CCR) at the Boswell facility, and on-going capital investment and upgrades to other steam generation units.
Hydro Production Plant	The increase is primarily due to on- going capital investment and upgrades to hydro generation units such as concrete and gate replacement projects.
Wind Production Plant	The increase is primarily due to on-going capital investment and upgrades to wind generation units such as blade and gearbox replacements.
Transmission Plant	The increase is primarily due to strategic capital investments related to the on-going transition of the Company's baseload coal generation fleet as well as on-going capital investments and upgrades to improve reliability and power quality.
Distribution Plant	The increase is primarily due to on-going capital investments and upgrades to improve reliability and power quality.
General Plant	The increase is primarily due to on-going capital investment.
Intangible Plant	The decrease is primarily due to retirements since the most recent rate case, partially offset by on-going capital investment, primarily software.

Item	Description and Basis
Accumulated Depreciation and Amortization	Depreciation and Amortization reserves increased, except for intangible plant primarily due to the additions of tangible plant, partially offset by retiring Boswell Units 1 and 2 in 2018 and transferring the accumulated depreciation balance to a regulated asset reflecting continued cost recovery through 2022. Amortization reserves for intangible plant decreased primarily due to retirements since the most recent rate case, partially offset by the additions of intangible plant.
Construction Work In Progress	The increase is primarily due to changes in the level of capital investment from year to year.
Working Capital	Fuel Inventory decreases are primarily due to bringing fuel inventory back to a normal level and the reduction in coal burn as a result of the retirement of Boswell Units 1 and 2. The last rate case had a high fuel inventory level as a result of building up fuel inventory before rail delivery rates increased. Prepayment increases are primarily due to inclusion of the prepaid pension asset and the prepaid OPEB asset in rate base.
Unamortized Boswell 1 and 2	The decrease is due to retiring Boswell Units 1 and 2 and transferring the plant balance and accumulated depreciation to a regulated asset in 2018 reflecting continued cost recovery through 2022. In 2022 the regulated asset for Boswell Units 1 and 2 is a credit balance so the adjustment reduces rate base.
Accumulated Deferred Income Taxes	The decrease is primarily due to book depreciation in excess of tax depreciation and additional production tax credits earned, partially offset by the inclusion of the accumulated deferred income taxes for the prepaid pension asset and the prepaid OPEB asset in rate base in the Proposed Test Year 2022.

Minnesota Power
Docket No. E015/GR-21-335

Comparison of Proposed Test Year to Most Recent General Rate Case
Statement of Operating Income
Direct Schedule E-3 (IR)

Line No.	Description	Minnesota Jurisdiction		
		Results of Most Recent Rate Case (E015\FR-16-664)	Proposed Test Year 2022	Difference
		(1)	(2)	(3)
1	Operating Revenue			
2	Sales by Rate Class	$644,599,005	$605,704,302	($38,894,703)
3	Dual Fuel	$10,538,568	$10,245,092	($293,476)
4	Intersystem Sales	$6,482,677	$32,670,849	$26,188,172
5	LP Demand Response		($1,922,400)	($1,922,400)
6	Sales for Resale	$126,505,800	$99,656,856	($26,848,944)
7	Total Revenue from Sales	$788,126,050	$746,354,699	($41,771,351)
8	Other Operating Revenue	$41,952,810	$34,497,278	($7,455,532)
9	Total Operating Revenue	$830,078,860	$780,851,977	($49,226,883)
10				
11	Operating Expenses Before AFUDC			
12	Operation and Maintenance Expenses			
13	Steam Production	($41,006,829)	($30,519,018)	$10,487,811
14	Hydro Production	($5,716,958)	($4,460,426)	$1,256,532
15	Wind Production	($13,766,390)	($15,417,511)	($1,651,121)
16	Solar Production			
17	Other Power Supply	$468,020	($1,594,103)	($2,062,123)
18	Purchased Power	($204,620,065)	($270,164,812)	($65,544,747)
19	Fuel	($122,233,712)	($80,953,554)	$41,280,158
20	Total Production	($386,875,934)	($403,109,424)	($16,233,490)
21	Transmission	($47,345,228)	($47,480,572)	($135,344)
22	Distribution	($23,697,619)	($27,110,481)	($3,412,862)
23	Customer Accounting	($6,362,302)	($6,385,512)	($23,210)
24	Customer Credit Cards	($350,000)	($294,188)	$55,812
25	Customer Service and Information	($2,746,697)	($1,519,732)	$1,226,965
26	Conservation Improvement Program	($10,447,625)	($10,714,344)	($266,719)
27	Sales	($40,958)	($1,856)	$39,102
28	Administrative and General	($48,386,941)	($59,802,931)	($11,415,990)
29	Charitable Contributions	($394,280)	($241,754)	$152,526
30	Interest on Customer Deposits	($1,071,000)	($1,248,000)	($177,000)
31	Total Operation and Maintenance Expenses	($527,718,584)	($557,908,795)	($30,190,211)
32	Depreciation Expense	($123,591,686)	($132,205,211)	($8,613,525)
33	Amortization Expense	($4,217,942)	($6,978,555)	($2,760,613)
34	Taxes Other Than Income Taxes	($42,278,734)	($37,219,842)	$5,058,892
35	Income Taxes	$1,213,049	($6,162,850)	($7,375,899)
36	Deferred Income Taxes	$8,516,506	$38,267,566	$29,751,060
37	Investment Tax Credit	$364,441	$445,778	$81,337
38	Total Operating Expenses Before AFUDC	($687,712,950)	($701,761,908)	($14,048,958)
39				
40	Operating Income Before AFUDC	$142,365,910	$79,090,068	($63,275,842)
41	Allowance for Funds Used During Construction	$2,367,898	$2,485,868	$117,970
42	**Total Operating Income**	**$144,733,808**	**$81,575,936**	**($63,157,872)**

General Description

Minnesota Power ("the Company") has identified those significant changes in the major categories of Operating Income since the last Order in Docket No. E015/GR-16-664 (2016 Rate Case). This summary explains changes shown in Direct Schedule E-3 (IR).

Item	**Description and Basis**
Operating Revenue:	The comparison of revenue by rate class is based on final rate revenue in Docket No. E015/GR-16-664 (2016 Rate Order) as compared to the interim rate revenue in the present docket (2022 test year).
Sales by Rate Class	The decrease in Sales by Class revenue from the 2016 Rate Order to the 2022 test year reflects a decline in load of approximately 18 percent, partially offset by recovery of higher fuel adjustment clause costs. The decrease in load reflects the impact of unfavorable market conditions that led to the closure or idling of businesses, including Blandin Paper Company's Paper Machine #5 in 2017 and Verso Corporation in 2020. Load loss due to energy efficiencies also reduced revenue. As part of the Company's 2019 rate case resolution effective July 1, 2020, higher firm energy rates were implemented along with margins on asset backed market sales flowing through the fuel adjustment clause. The decrease in revenue from the 2016 Rate Case Order to the 2022 test year is also due to various revenue adjustments applied to the 2022 test year that did not apply to the revenue in the 2016 Rate Case Order. These include the Excess ADIT, DR Product A Reassign, and LP Demand Response adjustments
Dual Fuel	No significant change.
Intersystem Sales	The increase in Intersystem Sales revenue from the 2016 Rate Order to the 2022 test year is primarily due to more sales to Silver Bay Power Corporation. In 2019, Silver Bay Power ceased self-generation.
LP Demand Response	In decrease in revenue shown in LP Demand Response is a result of the proposed DR Product A Reassign and LP Demand Response adjustments.
Sales for Resale	The decrease in Sales for Resale revenue from the 2016 Rate Order to the 2022 test year is primarily due to lower wholesale power sales as a 100 MW Large Market Contract expired on April 30, 2020. This decrease is partially offset by an increase in revenue from Minnkota Power Cooperative, Inc. (Minnkota Power) due to the resale of approximately 32 percent in 2022 (approximately 28 percent in 2016 Rate Case Order) of Minnesota Power's 50 percent output entitlement from Square Butte Electric Cooperative (Square Butte), under a power sales agreement with Minnkota Power which commenced June 1, 2014. See "Purchased Power" below.
Other Operating Revenue	Other Operating Revenue decreased from the 2016 Rate Order to the 2022 test year primarily due to the absence of revenue in the 2022 test year from steam sales due to the loss of a large power customer and coals sales due to the conversion of a Company facility to gas.
Operating Expenses	
Steam Production	Steam Production expense decreased from the 2016 Rate Order to the 2022 test year primarily due to the retirement of Units 1 and 2 at the Boswell Energy Center in December 2018, and lower labor and related benefit expenses at other units or facilities. These

General Description

Minnesota Power ("the Company") has identified those significant changes in the major categories of Operating Income since the last Order in Docket No. E015/GR-16-664 (2016 Rate Case). This summary explains changes shown in Direct Schedule E-3 (IR).

Item	Description and Basis
	decreases were partially offset by an adjustment reducing Steam Production expense in the most recent general rate case.
Hydro Production	Hydro Production expense decreased from the 2016 Rate Order to the 2022 test year primarily due to lower labor and related benefit expenses. These decreases were partially offset by an adjustment reducing Hydro Production expense in the most recent general rate case.
Wind Production	Wind Production expense increased from the 2016 Rate Order to the 2022 test year primarily due to escalation factors in the long-term service agreements for the Bison Wind Energy Center.
Other Power Supply	Other Power Supply expense increased from the 2016 Rate Order to the 2022 test year primarily due to an adjustment reducing Other Power Supply expense in the most recent general rate case.
Purchased Power	Purchased Power expense increased from 2020 to the 2022 test year primarily due additional long-term power purchase agreements, which include 250 MW of capacity and energy and 133 MW of energy only from Manitoba Hydro-Electric Board as well as 250 MW of wind generation from the Nobles 2 wind facility. These purchases and additional MISO market purchases are necessary to meet load requirements following the retirement of Boswell Energy Center Unit 1 and 2 at the end of 2018 and Boswell Energy Center Unit 3 moving to economic dispatch in July 2021. Minnesota Power is selling approximately 32 percent in 2022 (approximately 28 percent in 2016 Rate Order) of its 50 percent output entitlement from Square Butte to Minnkota Power, under a power sales agreement with Minnkota Power which commenced June 1, 2014. Minnkota Power's net entitlement increases and Minnesota Power's net entitlement decreases until Minnesota Power's share is eliminated at the end of 2025. See "Sales for Resale" above.
Fuel	Fuel expense decreased from the 2016 Rate Order to the 2022 test year primarily due to the retirement of Boswell Energy Center Units 1 and 2 at the end of 2018.
Transmission	No significant change.
Distribution	Distribution expenses increased from the 2016 Rate Order to the 2022 test year primarily due to higher vegetation management costs.
Customer Accounting	No significant change.
Customer Credit Cards	No significant change.
Customer Service and Information	Customer Service and Information expense decreased from the 2016 Rate Order to the 2022 test year primarily due to lower labor and benefits as well as an adjustment in the 2022 test year to remove SolarSense expenses that will remain in a continuing cost recovery rider, and lower labor and related benefit expenses.

General Description

Minnesota Power ("the Company") has identified those significant changes in the major categories of Operating Income since the last Order in Docket No. E015/GR-16-664 (2016 Rate Case). This summary explains changes shown in Direct Schedule E-3 (IR).

Item	Description and Basis
Conservation Improvement Program	No significant change.
Sales	No significant change.
Administrative and General	Administrative and General expenses increased from the 2016 Rate Order to the 2022 test year primarily due to adjustments reducing Administrative and General expense in the most recent general rate case, higher expense for insurance premiums, higher information technology hardware and software costs, and the absence of the deferred fuel adjustment clause. These increases were partially offset by lower benefit expenses.
Charitable Contributions	Charitable Contributions are based on an average of the three most recently completed years. The decrease is primarily due to fewer charitable contributions in the three most recently completed years preceding the 2022 test year compared to those preceding the last general rate case.
Interest on Customer Deposits	Primarily relates to weekly billings to Large Power customers which are reduced by an interest component that is included as a Company expense. Interest calculation is based on billings to customers which will vary from year to year.
Depreciation Expense	Depreciation Expense increased from the 2016 Rate Order to the 2022 test year primarily due to higher plant in-service. This increase is partially offset by the reclassification of Units 1 and 2 at the Boswell Energy Center as regulatory assets in December 2018. See "Amortization Expense".
Amortization Expense	Amortization expense increased from the 2016 Rate Order to the 2022 test year primarily due to the retirement of Units 1 and 2 at the Boswell Energy Center in December 2018, which are now classified as a regulatory asset with associated amortization for 2022 being amortized over three years. These units were included in depreciation expense in the most recent general rate case. See "Depreciation Expense". Higher intangible plant in-service also contributed to this increase.
Taxes Other Than Income Taxes	Taxes Other Than Income Taxes decreased from the 2016 Rate Order to the 2022 test year primarily due to an adjustment in the 2022 test year to remove taxes other than income taxes that will remain in a continuing cost recovery rider.
Income Taxes / Deferred Income Taxes	Income Taxes reflect lower pretax income and higher production tax credits in the 2022 test year.
Investment Tax Credit	No significant change.
Allowance for Funds Used During Construction	Allowance for Funds Used During Construction increased from the 2016 Rate Order to the 2022 test year primarily due to changes in the level of capital investment from year to year.

Line No.	Description	Calculation Note	Minnesota Jurisdiction: Results of Most Recent Rate Case (E015/GR-16-664)	Minnesota Jurisdiction: Proposed Test Year 2022	Minnesota Jurisdiction: Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,048,922,118	$2,113,031,861	$64,109,743
2	Operating Income Before AFUDC		$142,365,910	$79,090,068	($63,275,842)
3	AFUDC		$2,367,898	$2,485,868	$117,970
4	Operating Income	Line 2 + Line 3	$144,733,808	$81,575,936	($63,157,872)
5	Rate of Return	Line 4 / Line 1	7.0639%	3.8606%	(98.5152%)
6	Required Rate of Return		7.0639%	7.5133%	0.4494%
7	Required Operating Income	Line 1 * Line 6	$144,733,808	$158,758,423	$288,109
8	Operating Income Deficiency	Line 7 - Line 4		$77,182,487	$63,445,981
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9		$108,314,136	
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$606,231,184	$615,949,394	$9,718,210
12	Required Percent Increase	Line 10 / Line 11		17.5849%	

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Proposed Test Year 2022	Proposed Interim Rates 2022	Difference	Proposed Test Year 2022	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
1	Plant In Service						
2	Steam	$1,549,096,105	$1,549,096,105		$1,363,731,716	$1,363,731,716	
3	Hydro	$216,868,175	$216,868,176	$1	$189,923,705	$189,924,458	$753
4	Wind	$800,688,822	$800,688,822		$701,161,540	$701,161,540	
5	Transmission	$850,297,390	$850,297,390		$698,508,020	$698,508,020	
6	Distribution	$700,977,702	$700,977,702		$666,417,408	$666,417,408	
7	General Plant	$231,282,316	$231,282,306	($9)	$205,636,111	$205,637,403	$1,292
8	Intangible Plant	$68,305,428	$68,305,426	($3)	$60,731,244	$60,731,625	$381
9	Total Plant In Service	$4,417,515,937	$4,417,515,926	($11)	$3,886,109,743	$3,886,112,169	$2,426
10							
11	Accumulated Depreciation and Amortization						
12	Steam	($778,377,792)	($778,377,792)		($684,621,867)	($684,621,867)	
13	Hydro	($46,582,894)	($46,582,895)	($1)	($40,803,409)	($40,803,571)	($162)
14	Wind	($198,874,331)	($198,874,331)		($174,165,052)	($174,165,052)	
15	Transmission	($296,723,244)	($296,723,244)		($243,569,856)	($243,569,856)	
16	Distribution	($335,096,210)	($335,096,210)		($318,622,695)	($318,622,695)	
17	General Plant	($107,709,322)	($107,709,318)	$4	($95,765,757)	($95,766,359)	($602)
18	Intangible Plant	($39,943,271)	($39,943,270)	$2	($35,514,081)	($35,514,304)	($223)
19	Total Accumulated Depreciation and Amortization	($1,803,307,064)	($1,803,307,059)	$5	($1,593,062,718)	($1,593,063,705)	($987)
20							
21	Net Plant Before CWIP						
22	Steam	$770,718,313	$770,718,313		$679,109,849	$679,109,849	
23	Hydro	$170,285,281	$170,285,281	$0	$149,120,296	$149,120,887	$591
24	Wind	$601,814,490	$601,814,490		$526,996,487	$526,996,487	
25	Transmission	$553,574,146	$553,574,146		$454,938,164	$454,938,164	
26	Distribution	$365,881,492	$365,881,492		$347,794,713	$347,794,713	
27	General Plant	$123,572,993	$123,572,988	($5)	$109,870,354	$109,871,044	$690
28	Intangible Plant	$28,362,157	$28,362,156	($1)	$25,217,162	$25,217,321	$158
29	Total Net Plant Before CWIP	$2,614,208,873	$2,614,208,867	($6)	$2,293,047,025	$2,293,048,464	$1,439
30	Construction Work in Progress	$42,350,038	$42,350,036	($1)	$35,783,783	$35,783,807	$24
31	Utility Plant	$2,656,558,911	$2,656,558,903	($7)	$2,328,830,808	$2,328,832,271	$1,463
32							
33	Working Capital						
34	Fuel Inventory	$17,141,063	$17,141,063		$14,689,205	$14,689,646	$441
35	Materials and Supplies	$28,190,509	$28,190,509	$0	$24,599,288	$24,599,288	$0
36	Prepayments	$130,343,706	$28,024,861	($102,318,845)	$115,202,736	$24,230,206	($90,972,529)
37	Cash Working Capital	($44,266,222)	($43,857,315)	$408,906	($39,778,461)	($39,366,227)	$412,233
38	Total Working Capital	$131,409,056	$29,499,117	($101,909,938)	$114,712,769	$24,152,914	($90,559,855)
39							
40	Additions and Deductions						
41	Asset Retirement Obligation						
42	Electric Vehicle Program						
43	Workers Compensation Deposit	$80,105	$80,105	($0)	$71,222	$71,223	$0
44	Unamortized WPPI Transmission Amortization	($517,730)	($517,730)	($0)	($425,308)	($425,308)	($0)
45	Unamortized UMWI Transaction Cost	$1,201,867	$1,201,867	$0	$987,318	$987,318	$0
46	Unamortized Boswell 1 and 2	($5,565,460)	($5,565,460)		($4,893,264)	($4,893,264)	
47	Customer Advances	($1,762,180)	($1,762,180)		($1,762,180)	($1,762,180)	
48	Other Deferred Credits - Hibbard	($339,222)	($339,222)	($0)	($298,251)	($298,251)	($0)
49	Wind Performance Deposit	($150,000)	($150,000)		($131,883)	($131,883)	
50	Accumulated Deferred Income Taxes	($369,953,437)	($331,948,012)	$38,005,425	($324,059,370)	($290,412,218)	$33,647,152
51	Total Additions and Deductions	($377,006,057)	($339,000,632)	$38,005,425	($330,511,716)	($296,864,563)	$33,647,152
52							
53	**Total Average Rate Base**	**$2,410,961,909**	**$2,347,057,389**	**($63,904,521)**	**$2,113,031,861**	**$2,056,120,621**	**($56,911,240)**

General Description

The Company has identified those significant items affecting changes in the major categories of Rate Base for Proposed Interim Rates compared to Proposed Test Year 2022. This summary explains changes shown in Direct Schedule F-1 (IR).

Item	Description and Basis
Prepayments	Prepayment differences are primarily due to inclusion of the prepaid pension asset and the prepaid OPEB asset in rate base for the Proposed Test Year, but not for Proposed Interim Rates.
Accumulated Deferred Income Taxes	The increase in Accumulated Deferred Income Taxes is associated with the change for income prepayments for the prepaid pension asset and the prepaid OPEB asset described above.

Line No.	Description	Total Company			Minnesota Jurisdiction		
		Proposed Test Year 2022	Proposed Interim Rates 2022	Difference	Proposed Test Year 2022	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
1	Operating Revenue						
2	Sales by Rate Class	$698,200,594	$695,910,394	($2,290,200)	$605,704,302	$603,414,102	($2,290,200)
3	Dual Fuel	$10,245,092	$10,245,092		$10,245,092	$10,245,092	
4	Intersystem Sales	$38,067,674	$38,067,674		$32,670,849	$32,671,772	$923
5	LP Demand Response	($1,922,400)		$1,922,400	($1,922,400)		$1,922,400
6	Sales for Resale	$115,185,926	$115,185,926		$99,656,856	$99,658,724	$1,867
7	Total Revenue from Sales	$859,776,886	$859,409,086	($367,800)	$746,354,699	$745,989,689	($365,010)
8	Other Operating Revenue	$41,596,649	$41,596,649	($0)	$34,497,278	$34,497,318	$40
9	Total Operating Revenue	$901,373,535	$901,005,735	($367,800)	$780,851,977	$780,487,008	($364,969)
10							
11	Operating Expenses Before AFUDC						
12	Operation and Maintenance Expenses						
13	Steam Production	($35,127,108)	($35,127,108)		($30,519,018)	($30,519,440)	($422)
14	Hydro Production	($5,146,274)	($5,146,274)		($4,460,426)	($4,460,500)	($74)
15	Wind Production	($17,535,442)	($17,535,442)		($15,417,511)	($15,417,511)	
16	Other Power Supply	($1,813,088)	($1,813,088)		($1,594,103)	($1,594,103)	
17	Purchased Power	($313,161,547)	($313,161,547)		($270,164,812)	($270,170,787)	($5,975)
18	Fuel	($94,465,966)	($94,465,966)		($80,953,554)	($80,955,983)	($2,429)
19	Total Production	($467,249,425)	($467,249,425)		($403,109,424)	($403,118,324)	($8,900)
20	Transmission	($57,798,343)	($57,798,343)	($0)	($47,480,572)	($47,480,572)	($0)
21	Distribution	($28,586,273)	($28,586,273)	$0	($27,110,481)	($27,110,481)	$0
22	Customer Accounting	($6,438,438)	($6,438,438)		($6,385,512)	($6,385,512)	
23	Customer Credit Cards	($294,188)	($294,188)		($294,188)	($294,188)	
24	Customer Service and Information	($1,535,653)	($1,531,514)	$4,139	($1,519,732)	($1,515,636)	$4,096
25	Conservation Improvement Program	($10,714,344)	($10,714,344)		($10,714,344)	($10,714,344)	
26	Sales	($1,856)	($1,856)		($1,856)	($1,856)	
27	Administrative and General	($67,482,455)	($67,174,431)	$308,024	($59,802,931)	($59,529,378)	$273,552
28	Charitable Contributions	($271,905)	($271,905)	$0	($241,754)	($241,756)	($2)
29	Interest on Customer Deposits	($1,248,000)	($1,248,000)	$0	($1,248,000)	($1,248,000)	$0
30	Total Operation and Maintenance Expenses	($641,620,881)	($641,308,717)	$312,163	($557,908,795)	($557,640,048)	$268,747
31	Depreciation Expense	($149,593,464)	($149,593,462)	$2	($132,205,211)	($132,205,265)	($54)
32	Amortization Expense	($7,864,938)	($7,864,938)	$0	($6,978,555)	($6,978,591)	($36)
33	Taxes Other Than Income Taxes	($41,733,954)	($41,733,954)	($0)	($37,219,842)	($37,219,906)	($64)
34	Income Taxes	($9,182,944)	($9,533,878)	($350,935)	($6,162,850)	($6,461,923)	($299,073)
35	Deferred Income Taxes	$43,703,802	$43,703,802	($0)	$38,267,566	$38,267,588	$22
36	Investment Tax Credit	$510,490	$510,490	$0	$445,778	$445,778	$0
37	Total Operating Expenses Before AFUDC	($805,781,888)	($805,820,657)	($38,769)	($701,761,908)	($701,792,366)	($30,457)
38							
39	Operating Income Before AFUDC	$95,591,647	$95,185,078	($406,569)	$79,090,068	$78,694,642	($395,427)
40	Allowance for Funds Used During Construction	$2,942,167	$2,942,167	($0)	$2,485,868	$2,485,869	$2
41	**Total Operating Income**	**$98,533,814**	**$98,127,245**	**($406,569)**	**$81,575,936**	**$81,180,511**	**($395,425)**

General Description

The Company has identified those significant items affecting changes in the major categories of Operating Income for Proposed Interim Rates compared to Proposed Test Year**.** This summary explains changes shown in Direct Schedule F-3(IR).

Item	Description and Basis
DR Product A	Proposed Test Year adjustment to reassign DR Product A and Curtailable revenue out of Sales by Rate Class revenue into LP Demand Response revenues. The adjustment is shown on Direct Schedule C-10, Page 5 of 6, column 27 (Total Company) and Direct Schedule C-9, Page 5 of 6, column 27 (MN Jurisdiction). Volume 4, Workpaper ADJ-IS-27 includes the details.
LP Demand Response	Proposed Test Year adjustment to remove portion of DR Product A revenue to reflect full year of lower Product A kW concurrently with an increase in the Product A discount. The adjustment is shown on Direct Schedule C-10, Page 5 of 6, column 28 (Total Company) and Direct Schedule C-9, Page 5 of 6, column 28 (MN Jurisdiction). Volume 4, Workpaper ADJ-IS-28 includes the details.
Economic Development	Proposed to recover 100 percent of Economic Development expenses instead of 50 percent in Interim Rates. The Interim Rate adjustment that is not applied in the Proposed Test Year is shown on Direct Schedule B-8(IR), Page 1 of 6, column 4 (Total Company) and Direct Schedule B-7(IR), Page 1 of 6, column 4 (MN Jurisdiction). Volume 4, Workpaper ADJ-IS-3 includes the details.
`	
Income Taxes	The changes described above also affects Income Taxes as shown in Direct Schedule F-3(IR).
Jurisdictional Changes	In addition to the changes above, a number of changes occur in the Minnesota Jurisdiction as a result of changes to allocation factors due to all test year adjustments.

Line No.	Description	Calculation Note	Minnesota Jurisdiction		
			Proposed Test Year 2022	Proposed Interim Rates 2022	Difference
		(1)	(2)	(3)	(4)
1	Average Rate Base		$2,113,031,861	$2,056,120,621	($56,911,240)
2	Operating Income Before AFUDC		$79,090,068	$78,694,642	($395,427)
3	AFUDC		$2,485,868	$2,485,869	$2
4	Operating Income	Line 2 + Line 3	$81,575,936	$81,180,511	($395,425)
5	Rate of Return	Line 4 / Line 1	3.8606%	3.9482%	0.6948%
6	Required Rate of Return		7.5133%	6.9752%	(0.5381%)
7	Required Operating Income	Line 1 * Line 6	$158,758,423	$143,418,526	$306,239
8	Operating Income Deficiency	Line 7 - Line 4	$77,182,487	$62,238,015	$701,664
9	Gross Revenue Conversion Factor		1.40335	1.40335	
10	Revenue Deficiency	Line 8 * Line 9	$108,314,136	$87,341,793	
11	Present Rates Revenue From Sales by Rate Class and Dual Fuel		$615,949,394	$613,659,194	($2,290,200)
12	Required Percent Increase	Line 10 / Line 11	17.5849%	14.2329%	

Section VI

RULES AND REGULATIONS

RESIDENTIAL SERVICE

RATE CODES

Residential - General	20
Residential - Space Heating	22
Residential - Seasonal	23

APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations and any applicable Riders. There is a maximum of one Residential – General or Residential – Space Heating service per customer. Any additional residence shall be provided service at Residential - Seasonal rate.

A dwelling will be considered to be occupied seasonally when occupied as customer's principal dwelling place for eight months or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	$8.00	$10.00
All kWh (¢/kWh)	9.693¢	9.341¢

0 kWh to 600 kWh discount for eligible customers -3.622¢

Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

RESIDENTIAL SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

~~9.~~10. An eligible customer is defined as a customer who has average monthly usage that is less than or equal to the usage threshold of 1,000 kWh. The qualification for the discount would be based on a monthly usage average using twelve months of historical usage.

~~10.~~11. The discount for eligible customers is applied to the first 600 kWh each month, as applicable.

RESIDENTIAL SERVICE

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$8.00
Energy Charge	
All kWh (per kWh)	5.888¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

~~5.~~6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. The duration and frequency of interruptions shall be at the discretion of Company. Interruption will normally occur at such times:

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(a) when Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
(b) when Company expects to incur a new system peak,
(c) at such other times when in Company's opinion the reliability of the system is endangered,
(d) when Company performs necessary testing for certification of interruptibility of customers' loads.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. Company will provide, at customer's expense, and customer will install, as directed by Company, a load-break switch or circuit breaker. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$8.00
Energy Charge All kWh (per kWh)	5.249¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

~~5.~~6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

To electric service for residential customers for the sole purpose of recharging electric vehicle(s). Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$4.25
Off-Peak Energy Charge All kWh (per kWh)	2.391¢
On-Peak Energy Charge All kWh (per kWh)	10.251¢

Plus any applicable Adjustments.

RENEWABLE ENERGY OPTION

Customers taking service under this schedule have the option to purchase energy from the Company's current mix of energy supply sources at the rates shown above or entirely from renewable energy sources. "Renewable energy" means electricity generated through use of any of the following resources: wind, solar, geothermal, hydro, trees or other vegetation, or landfill gas. Participation by the Customer is voluntary, and Customers who elect this option shall commit to renewable energy for no less than one year. The rate for the renewable energy option will include a 2.5¢ per kWh surcharge in addition to the per kWh energy charges shown above.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

~~5.~~6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

SERVICE CONDITIONS

1. The Residential Off-Peak Electric Vehicle Service load shall be separately served and metered and shall at no time be connected to facilities serving Customer's other loads. To be eligible for this rate, Customer must also take Residential Service under the General, Space Heating, or Seasonal rate.

2. The total connected off-peak load shall not exceed 100 kW.

3. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

5. On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$12.00
Energy Charge for all kWh	8.639¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$12.00
Demand Charge for all kW	$6.50
Energy Charge for all kWh	6.054¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

GENERAL SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

GENERAL SERVICE

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 85% (90% effective December 1, 2019) and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% (90% effective December 1, 2019) lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

29EV

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$12.00
Demand Charge for On-Peak kW	$6.50
Energy Charge for all kWh	6.054¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m., Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, three phase, or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system).

RATE (Monthly)

Service Charge

Low Voltage Service	$12.00
High Voltage Service	$12.00

Energy Charge

Low Voltage Service	5.888¢ per kWh
High Voltage Service	5.256¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:

   (a) when Company is required to purchase or generate power at a cost higher than customer's energy charge,
   (b) when Company expects to incur a system peak,
   (c) when in Company's opinion the reliability of the system is endangered, or
   (d) when Company performs necessary testing of interruptibility of customer's loads.

   Interruptions shall normally occur for reliability-related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. The customer will install, at its expense, a load-break switch, circuit breaker, or other means of allowing Company to automatically interrupt customer's Dual Fuel load by sending a command or signal. The Company reserves the right to inspect and approve the installation to ensure compliance and consistency with Company's interruption system. If Company's system cannot support automatic interruption, interruption shall be made in accordance with Service Condition 8. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

8. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, whenever the Company determines such interruption is necessary. Customers with existing provisions in their Electric Service Agreements for longer notice before interruption shall continue to have thirty (30) minutes to shed their interruptible loads through the term of their existing contracts or December 31, 1998, whichever is later.

9. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Midcontinent Independent System Operator (MISO) in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

   (a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).
   (b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer's service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company’s 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company’s 13,000 volt system), supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	
High Voltage Service	$12.00
Low Voltage Service	$12.00
Energy Charge	
High Voltage Service-Low Voltage	4.623¢ per kWh
Low Voltage Service	5.249¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city’s Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,200.00
All additional kW of Billing Demand ($/kW)	$10.50
Energy Charge	
All kWh (¢/kWh)	4.148¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will also be subject to a discount of 0.350¢ per kWh of Energy.

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

LARGE LIGHT AND POWER SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~8.~~9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the lower of:

LARGE LIGHT AND POWER SERVICE

a) 75% of the greatest adjusted demand during the preceding eleven months, or
b) The greatest adjusted demand during the preceding eleven months minus 100 kW.

However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 85% (90% effective December 1, 2019) and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% (90% effective December 1, 2019) lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

RATE CODES

73

APPLICATION

To the electric service requirements of a customer requiring service for no less than 2,000 kW and no more than 50,000 kW of connected load, where such electric service requirements are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at the voltage level specified in customer's contract.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Light and Power Service Rate Schedules 75 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Light and Power Service Rate Schedules 75 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

~~2.~~3. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");

(b) The voltage level(s) at which service will be supplied;

(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;

(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;

(e) A confidentiality agreement; and

(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

LARGE POWER SERVICE

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company ("Confidential Information"), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term "Holidays" shall mean New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year's Eve Day.

For purposes of ESAs, the term "Office" shall mean the Minnesota Office of Energy Security or its successor organization.

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

LARGE POWER SERVICE

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$250,087
All additional kW of Firm Demand ($/kW)	$24.96

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.041¢

Excess Energy Charge

All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under "ENERGY."

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Interim Rate Adjustment. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

~~2.~~3. Fuel and Purchased Energy Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Adjustment and a conservation program.

~~3.~~4. Conservation Adjustment. Adjustment will be determined in accordance with the Rider for Conservation Program Adjustment.

~~4.~~5. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

LARGE POWER SERVICE

~~5.~~6. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

~~6.~~7. CARE Low-Income Affordability Program Surcharge: There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

~~7.~~8. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~8.~~9. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~9.~~10. Franchise Fee. An adjustment for customers located within the corporate limits of the applicable city as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be based on amount specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this a mount shall be deemed to be the

LARGE POWER SERVICE

Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases. For all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—

LARGE POWER SERVICE

Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion

For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company's estimated annual Revenue Requirements per kW associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Energy Portion

LARGE POWER SERVICE

For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$300,104
All additional kW of Non-Contract Billing Demand ($/kW)	$29.95

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.014¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY."

Plus any applicable Adjustments.

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

NON-CONTRACT LARGE POWER SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment. Such Fuel Adjustment shall be applicable to Customer's Non-Contract Firm Energy only.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

~~5.~~6. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive

NON-CONTRACT LARGE POWER SERVICE

demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power

NON-CONTRACT LARGE POWER SERVICE

for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

Capacity Portion
For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

Energy Portion
For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

NON-CONTRACT LARGE POWER SERVICE

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 74 for which a ten (10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes no responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

RATE CODES

79

APPLICATION

To the electric service requirements of a customer requiring 10,000 kW or more, where the electric service requirements of 10,000 kW or more are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Three phase, 60 hertz at high voltage of 13,000 through 69,000 volts or at transmission voltage of 115,000 volts.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Power Service Rate Schedules 74 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Power Service Rate Schedules 74 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

~~2.~~3. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Lamp Type & Size Sub rate code	CIS Code	**Rate Per Lamp Per Month** Option 1 _ _A	Option 2 _ _B (Option 2 Closed to New Installation)	Option 3 _ _C (Option 3 Closed to New Installation)	Option 4 _ _D
Mercury Vapor Lamps (Closed to New Installation)					
7,000 Lumens (175 watts)	MV175W	$11.77	$8.23		
20,000 Lumens (400 watts)	MV400W	$18.73	$12.40		
55,000 Lumens (1,000 watts)	MV1000W	$34.89	$24.58		
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	SV100W	$10.32	$5.96	$5.96	
14,000 Lumens (150 watts)	SV150W	$11.90	$7.60		
23,000 Lumens (250 watts)	SV250W2	$16.88	$10.12	$10.19	
45,000 Lumens (400 watts)	SV400W	$22.60	$14.89	$10.81	
Metal Halide Lamps					
17,000 Lumens (250 watts)	MH250W	$16.69			
28,800 Lumens (400 watts)	MH400W	$20.33		$12.05	
88,000 Lumens (1,000 watts)	MH1000W	$33.87		$22.00	
Light Emitting Diodes (LED)					
4,674 Lumens (48 watts or less)	LED48W	$9.00			
10,000 Lumens (71 watts or less)	LED71W	$12.02			
24,000 Lumens (184 watts or less)	LED184W	$18.16			
46,800 Lumens (320 watts or less)	LED320W	$26.12			

Filing Date November 1, 2021~~January 19, 2021~~ **MPUC Docket No.** E015/GR-21-335~~E015/M-20-825~~
Effective Date January 1, 2022~~October 1, 2021~~ **Order Date** ~~April 20, 2021~~

Approved by: David R. Moeller
David R. Moeller
Senior Attorney & Director of Regulatory Compliance

OUTDOOR AND AREA LIGHTING SERVICE

Pole Charge Each pole used for service under this schedule only	MPPOLE	$10.50	$10.50	$10.50	
Monthly Service Charge		Included	Included	Included	$3.34
Energy Charge - Per kWh		Included	Included	Included	5.990

Plus any applicable adjustments

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

   The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~6.~~7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

OUTDOOR AND AREA LIGHTING SERVICE

~~7.~~8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	Daily Estimates	4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture by type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH250W	3	1,260	139	114	110	91	79	70	76	88	101	120	130	142
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MH1000W	12	4,410	485	398	385	317	277	245	264	309	353	421	457	499
LED48W	1	207	23	19	18	15	13	11	12	14	17	20	21	24
LED71W	1	298	33	27	26	21	19	17	18	21	24	28	31	34
LED184W	2	773	85	70	68	56	49	43	46	54	62	74	80	87
LED320W	4	1,344	148	121	117	97	84	75	81	94	108	128	139	152

Company shall furnish all electric energy required for service under this schedule.

OUTDOOR AND AREA LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

Option 1

COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, lamp, ballast, photo-electric control and wiring.

Option 2

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include, but not be limited to, the fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications.

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option, including poles, except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

OUTDOOR AND AREA LIGHTING SERVICE

Option 4

CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications. Company's point of delivery shall be on the Company's side of disconnect switch either at the weather head for overhead service or at the pad mount transformer for underground service.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a

OUTDOOR AND AREA LIGHTING SERVICE

single pole, Company's investment in additional facilities, over and above those which would be required for a single standard bracket mounting, shall not exceed $15.00 per light. Additional required investment will be at Customer's expense.

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For lamps which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Materials charges per the Company's cost for lighting replacement equipment plus the then current Material Handling Expense and A&G expense per Company's Accounting Manual.

MUNICIPAL PUMPING

RATE CODES

87

APPLICATION

To electric service supplied to a municipality for the operation of water pumping and sewage disposal facilities, where all such facilities are completely electrified and operated by service of Company, subject to Company's Electric Service Regulations and any applicable Riders. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service under this Schedule is closed to new customers. Existing customer(s) shall be gradually transitioned to an alternative applicable Rate Schedule.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$12.00
Energy Charge	
All kWh (¢/kWh)	8.639¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$12.00
Demand Charge	
All kW ($/kW)	$6.50
Energy Charge	
All kWh (¢/kWh)	6.054¢

Plus any applicable Adjustments.

MUNICIPAL PUMPING

MINIMUM CHARGE (Monthly)

Demand Charge per kW of Billing Demand but not less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~3.~~4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~4.~~5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~5.~~6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

~~6.~~7. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

MUNICIPAL PUMPING

~~8.~~9. Bills for service to Municipalities within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will also be subject to a discount of 0.350¢ per kWh of Energy.

DETERMINATION OF BILLING DEMAND

The Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than 5 kW.

Demand will be adjusted by multiplying by 85% (90% effective December 1, 2019) and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% (90% effective December 1, 2019) lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

Maximum use created by the operation of fire pumps will be disregarded if Company is notified promptly.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Five years, automatically renewable for one year periods unless canceled by 30 days' written notice by either party to the other prior to any renewal date.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Lamp Type & Size Sub rate code	CIS Code	Rate Per Fixture Per Month Option 1 _ _A	Option 2 _ _B (Option 2 Closed to New Installation)	Option 3 _ _C Option 3 Closed to New Installation)	Option 4 _ _D
Mercury Vapor Lamps (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$16.25	$9.70	$8.10	
10,000 Lumens (250 watts)	MV250W			$10.29	
20,000 Lumens (400 watts)	MV400W	$22.10	$15.00	$13.90	
55,000 Lumens (1,000 watts)	MV1000W2			$25.00	
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	SV100W	$14.35	$7.62	$6.50	
14,000 Lumens (150 watts)	SV150W	$15.88	$8.92	$9.15	
14,000 Lumens (150 watts)	SV150W-P			$8.30	
20,500 Lumens (200 watts)	SV200W	$19.65	$12.06	$10.00	
23,000 Lumens (250 watts)	SV250W	$19.78	$12.70	$10.80	
45,000 Lumens (400 watts)	SV400W	$24.30	$17.98	$13.00	
Metal Halide Lamps					
28,800 Lumens (400 watts)	MH400W		$15.90		
Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$13.60			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$18.10			

STREET AND HIGHWAY LIGHTING SERVICE

23,000 Lumens (219 watts or less, but more than 118 watts) LED219W	$22.50				
30,000 Lumens (278 watts or less) LED278W	$22.50				
Monthly Service Charge		Included	Included	Included	$3.34
Energy Charge - Per kWh		Included	Included	Included	5.990¢
Plus any applicable adjustments					

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

~~1.~~2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

~~2.~~3. The monthly fuel and purchased energy adjustment per fixture shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

~~3.~~4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

~~4.~~5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

~~5.~~6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

~~6.~~7. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

~~7.~~8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

Filing Date November 1, 2021~~January 19, 2021~~ **MPUC Docket No.** E015/GR-21-335~~E015/M-20-825~~

Effective Date January 1, 2022~~October 1, 2021~~ **Order Date** ~~April 20, 2021~~

Approved by: David R. Moeller
David R. Moeller
Senior Attorney & Director of Regulatory Compliance

STREET AND HIGHWAY LIGHTING SERVICE

~~8.~~9. Bills for service to parties within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	Daily Estimates	4,200	462	379	367	302	264	233	252	294	336	401	435	475
	Montly kWh usage per fixture by type													
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W2	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV150W-P	1	468	51	42	41	34	29	26	28	33	37	45	48	54
SV200W	3	1,140	125	103	100	82	72	63	68	80	91	109	118	129
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

Company shall furnish all electric energy required for service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1

COMPANY TO OWN AND MAINTAIN.

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, fixture, ballast, photo-electric control, driver, and wiring.

Option 2

The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's facilities. The equipment shall include, but not be limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications. In all cases, poles are owned by Company.

The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls. Option 2 is closed to new installations.

Option 3

The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, lamp, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

STREET AND HIGHWAY LIGHTING SERVICE

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned out lamps and photo-electric controls and will clean or replace glassware at the time of lamp replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4

CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install in master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of fixtures of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For fixtures which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

7. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

8. Existing Option 1 Customers who wish to replace Sodium Vapor fixtures that are less than ten years old and not in need of significant maintenance or repair with LED street lights will pay Company the remaining un-depreciated facility cost. Under Option 2, Customers who convert to LED street lights will be assessed a removal fee of $50 if the mast arm is left up and reused or $100 if the mast arm is removed and not reused. Under Option 3, the Company’s Compatible Unit Estimator (CUE) will be used to estimate the removal fee with a true-up of actual costs once the work is completed.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

~~RIDER FOR 2017 FEDERAL TAX CUT REFUND~~

~~APPLICATION~~

~~Applicable to electric service under all Retail Rate Schedules (and including all applicable Riders thereto) except that this Rider shall not be applicable to service under Company's Rider for Large Power Interruptible Service, Rider for Large Power Incremental Production Service or Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is not applicable to billings under the Rider for Conservation Program Adjustment, Rider for Renewable Resources, Rider for Transmission Cost Recovery, Rider for Customer Affordability of Residential Electricity (CARE), Rider for Boswell Unit 4 Emission Reduction Rider for Voluntary Renewable Energy, and Pilot Rider for Community Solar Garden.~~

~~ADJUSTMENT~~

~~There shall be applied to Customer's monthly bill an Excess Accumulated Deferred Income Tax (Excess ADIT) refund factor applicable to all charges for service taken under Company's standard rate schedules (except as described above):~~

~~All applicable Retail Rate Customers:~~ ~~-1.5259% refund factor~~

~~Filing Date April 23, 2020~~ ~~MPUC Docket No. E015/M-20-429~~
~~Effective Date July 1, 2020~~ ~~Order Date June 30, 2020~~

~~Approved by: David R. Moeller~~
~~**David R. Moeller**~~
~~**Senior Attorney and Director of Regulatory Compliance**~~

Section VI

RULES AND REGULATIONS

Section VII

STANDARD CONTRACTS AND AGREEMENTS

RESIDENTIAL SERVICE

RATE CODES

Residential - General	20
Residential - Space Heating	22
Residential - Seasonal	23

APPLICATION

To electric service for all domestic uses for residential customers in single-family dwellings subject to Company's Residential Service Rules, Extension Rules, Electric Service Regulations and any applicable Riders. There is a maximum of one Residential – General or Residential – Space Heating service per customer. Any additional residence shall be provided service at Residential - Seasonal rate.

A dwelling will be considered to be occupied seasonally when occupied as customer's principal dwelling place for eight months or less each year.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

	General & Space Heating	Seasonal
Service Charge	\$8.00	\$10.00
All kWh (¢/kWh)	9.693¢	9.341¢

0 kWh to 600 kWh discount for eligible customers -3.622¢
Plus any applicable Adjustments.

MINIMUM CHARGE

The Minimum Charge (monthly) shall be the Service Charge plus any applicable Adjustments.

In the case of Seasonal Service, the Minimum Charge (annually) shall not be less than the guaranteed annual revenue based on Company's Extension Rules.

RESIDENTIAL SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly billing, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

10. An eligible customer is defined as a customer who has average monthly usage that is less than or equal to the usage threshold of 1,000 kWh. The qualification for the discount would be based on a monthly usage average using twelve months of historical usage.

11. The discount for eligible customers is applied to the first 600 kWh each month, as applicable.

RESIDENTIAL SERVICE

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

For Seasonal Residential Service, the initial contract period is one year or such longer period as may be required under an extension agreement, with one year renewal periods.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

21

APPLICATION

To the interruptible electric service requirements of all-year Residential Customers where a non-electric source of energy is available to satisfy these requirements during periods of interruption. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, 60 hertz, at 120 to 120/240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$8.00
Energy Charge All kWh (per kWh)	 5.888¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. The backup heating source must be a non-electric, externally vented heating system, of sufficient size, capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. The duration and frequency of interruptions shall be at the discretion of Company. Interruption will normally occur at such times:

RESIDENTIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

(a) when Company is required to use oil-fired generation equipment or to purchase power that results in equivalent production cost,
(b) when Company expects to incur a new system peak,
(c) at such other times when in Company's opinion the reliability of the system is endangered,
(d) when Company performs necessary testing for certification of interruptibility of customers' loads.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. Company will provide, at customer's expense, and customer will install, as directed by Company, a load-break switch or circuit breaker. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODES

24

APPLICATION

To electric service for residential customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$8.00
Energy Charge	
All kWh (per kWh)	5.249¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 100 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

RESIDENTIAL CONTROLLED ACCESS ELECTRIC SERVICE

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

RATE CODES

28

APPLICATION

To electric service for residential customers for the sole purpose of recharging electric vehicle(s). Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, 60 hertz, voltages of 120 to 240 volts, supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	$4.25
Off-Peak Energy Charge All kWh (per kWh)	 2.391¢
On-Peak Energy Charge All kWh (per kWh)	 10.251¢

Plus any applicable Adjustments.

RENEWABLE ENERGY OPTION

Customers taking service under this schedule have the option to purchase energy from the Company's current mix of energy supply sources at the rates shown above or entirely from renewable energy sources. "Renewable energy" means electricity generated through use of any of the following resources: wind, solar, geothermal, hydro, trees or other vegetation, or landfill gas. Participation by the Customer is voluntary, and Customers who elect this option shall commit to renewable energy for no less than one year. The rate for the renewable energy option will include a 2.5¢ per kWh surcharge in addition to the per kWh energy charges shown above.

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resource adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment. The combination of the fuel adjustment and the Conservation Program Adjustment shall be shown on customer's bill as the Resource Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 25 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

RESIDENTIAL ELECTRIC VEHICLE SERVICE

SERVICE CONDITIONS

1. The Residential Off-Peak Electric Vehicle Service load shall be separately served and metered and shall at no time be connected to facilities serving Customer's other loads. To be eligible for this rate, Customer must also take Residential Service under the General, Space Heating, or Seasonal rate.

2. The total connected off-peak load shall not exceed 100 kW.

3. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate.

5. On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

GENERAL SERVICE

RATE CODES

25

APPLICATION

To any customer's electric service requirements when the total electric requirements are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements of less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders.

Applicable to multiple metered service only in conjunction with the respective Rider for such service.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER

Service Charge	$12.00
Energy Charge for all kWh	8.639¢

CUSTOMERS WITH A DEMAND METER

Service Charge	$12.00
Demand Charge for all kW	$6.50
Energy Charge for all kWh	6.054¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments, however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the

price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

When customer's use exceeds 2500 kWh for three consecutive months or where the connected load indicates customer's demand may be greater than 10 kW, the customer may be placed on a demand rate.

The Billing Demand will then be the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract.

Demand will be adjusted by multiplying by 85% (90% effective December 1, 2019) and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% (90% effective December 1, 2019) lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

RATE CODES

29EV

APPLICATION

Available while this Pilot Program is in effect, to Commercial and Industrial customer's electric service requirements for electric vehicle loads including battery charging and accessory usage which are supplied through one meter. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery. Service hereunder is limited to Customers with total power requirements greater than 10 kW but less than 10,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers taking Service must reasonably cooperate with Company in providing information for annual compliance filings with the Minnesota Public Utilities Commission as set forth in the December 12, 2019 Order in Docket No. E015/M-19-337.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Service Charge	$12.00
Demand Charge for On-Peak kW	$6.50
Energy Charge for all kWh	6.054¢

Plus any applicable Adjustments.

MINIMUM CHARGE (Monthly)

The appropriate service charge plus any applicable Adjustments; however, in no event will the Minimum Charge (Monthly) for three phase service be less than $25.00 nor will the Demand Charge per kW of Billing Demand be less than the Minimum Demand specified in customer’s contract.

Plus any applicable Adjustments.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will be further subject to a discount 0.350¢ per kWh of Energy.

High Voltage Service shall not be available from the Low Voltage Network Area as designated by Company.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

PILOT FOR COMMERCIAL ELECTRIC VEHICLE CHARGING SERVICE

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

The Billing Demand will be the kW measured during the 15-minute period of customer's greatest use during the On-Peak periods during the month, as adjusted for power factor, but not less than the minimum demand specified in customer's contract. On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m., Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m., Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Demand will be adjusted by multiplying by 90% and dividing by the average monthly power factor in percent when the average monthly power factor is less than 90% lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

DEMAND CHARGE CAP

In no month shall the Demand Charge exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the Demand Charge, capping it at 30% of the pre-tax bill.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

RATE CODES

26

TERRITORY

Applicable to all Rate Areas.

APPLICATION

To the interruptible electric service requirements of Commercial/Industrial Customers where an alternative source of energy is available to satisfy these requirements during periods of interruption. Service shall be delivered at one point from facilities of adequate type and capacity and shall be metered at (or compensated to) the voltage of delivery. Service is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Single phase, three phase, or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system).

RATE (Monthly)

Service Charge	
Low Voltage Service	$12.00
High Voltage Service	$12.00
Energy Charge	
Low Voltage Service	5.888¢ per kWh
High Voltage Service	5.256¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than one year or such longer period as may be required under an Electric Service Agreement.

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

SERVICE CONDITIONS

1. The primary energy source for the Company approved Dual Fuel installation must be electric. An approved Dual Fuel installation requires that the secondary or back-up energy source be capable of continuous operation. Under no circumstances will firm electric service or a back-up generator qualify as the secondary or back-up energy source.

2. The interruptible load of the approved Dual Fuel installation shall be separately served and metered and shall at no time be connected to facilities serving customer's firm load.

3. The duration and frequency of interruptions shall be at the sole discretion of the Company. Interruption will normally occur at such times:

   (a) when Company is required to purchase or generate power at a cost higher than customer’s energy charge,
   (b) when Company expects to incur a system peak,
   (c) when in Company's opinion the reliability of the system is endangered, or
   (d) when Company performs necessary testing of interruptibility of customer’s loads.

   Interruptions shall normally occur for reliability-related needs before interruptions for any certified interruptible loads for Large Power, Large Light and Power, and General Service.

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer must be prepared to supply all of the interruptible load from an alternative energy source for up to 30% of customer's Dual Fuel requirements during any annual period.

6. The customer will install, at its expense, a load-break switch, circuit breaker, or other means of allowing Company to automatically interrupt customer’s Dual Fuel load by sending a command or signal. The Company reserves the right to inspect and approve the installation to ensure compliance and consistency with Company’s interruption system. If Company’s system cannot support automatic interruption, interruption shall be made in accordance with Service Condition 8. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's remote control equipment.

7. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are

COMMERCIAL/INDUSTRIAL DUAL FUEL INTERRUPTIBLE ELECTRIC SERVICE

not fully satisfied before switching to Dual Fuel service may be required to have their extension cost contributions recalculated.

8. Upon receiving a control signal from the Company, the Customer must shed its interruptible load in ten (10) minutes or less, and for a duration as required by the Company, whenever the Company determines such interruption is necessary. Customers with existing provisions in their Electric Service Agreements for longer notice before interruption shall continue to have thirty (30) minutes to shed their interruptible loads through the term of their existing contracts or December 31, 1998, whichever is later.

9. Those customers who fail to interrupt their interruptible load after being notified to do so by the Company shall be responsible for all costs incurred by the Company due to such failure, including but not limited to penalties assessed the Company by the Midcontinent Independent System Operator (MISO) in the event the Company experiences a system capacity deficiency. Those costs shall be charged on a pro rata basis to all customers who did not interrupt as requested. Such customers shall also be billed as follows:

   (a) The first failure to interrupt shall result in the Customer being billed for the entire month on the standard applicable General Service or Large Light and Power Service Schedule (thereby not receiving an interruptible discount).
   (b) If a second such failure to interrupt occurs, in addition to billing as specified in (a) above, the Company reserves the right to discontinue customer's service under the Dual Fuel Interruptible Electric Service Schedule.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

RATE CODE

27

APPLICATION

To electric service for commercial/industrial customers for controlled energy storage or other loads which will be energized only for the time period between 11 p.m. and 7 a.m. daily. Service is subject to Company's Electric Service Regulations and any applicable riders.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at low voltage (voltage level lower than that available from Company's 13,000 volt system) or high voltage (voltage level equal to or greater than that available from Company's 13,000 volt system), supplied through one meter at one point of delivery.

RATE (Monthly)

Service Charge	
High Voltage Service	$12.00
Low Voltage Service	$12.00
Energy Charge	
High Voltage Service-Low Voltage	4.623¢ per kWh
Low Voltage Service	5.249¢ per kWh

Plus any applicable Adjustments.

The High Voltage Service Rate is applicable where service is delivered and metered at (or compensated to) the available high voltage level (13,000 volt system or higher).

MINIMUM CHARGE (Monthly)

The Minimum Charge shall be the Service Charge plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Not less than thirty days or such longer period as may be required under an Electric Service Agreement.

SERVICE CONDITIONS

1. The controlled load shall be separately served and metered and shall at no time be connected to facilities serving customer's other loads.

2. The total connected controlled load shall not exceed 200 kW.

3. Any controlled energy storage load to which this service schedule applies must have sufficient capacity to satisfy the customer's energy needs during the non-energized period.

COMMERCIAL/INDUSTRIAL CONTROLLED ACCESS ELECTRIC SERVICE

4. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service except in the case of gross negligence on the part of the Company.

5. Customer's load shall be controlled by a switching device approved or supplied by Company and paid for and installed by Customer. Customer must provide a continuous 120 volt AC power source at Company's control point for operation of Company's control equipment.

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall pay Company the installed cost of any additional facilities required which are not supported by this rate. Customers who have guaranteed annual revenue commitments to support line extension costs under a firm rate schedule that are not fully satisfied before switching to Controlled Access Electric Service may be required to have their extension cost contributions recalculated.

LARGE LIGHT AND POWER SERVICE

RATE CODES

75

APPLICATION

To the entire electric service requirements on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service hereunder is limited to Customers with total power requirements of less than 50,000 kW and is subject to Company's Electric Service Regulations and any applicable Riders. Customers with total power requirements in excess of 10,000 kW shall be served under this rate only where customer and Company have executed an electric service agreement having an initial minimum term of ten (10) years with a minimum cancellation provision of four (4) years.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

Demand Charge	
For the first 100 kW or less of Billing Demand	$1,200.00
All additional kW of Billing Demand ($/kW)	$10.50
Energy Charge	
All kWh (¢/kWh)	4.148¢

Plus any applicable Adjustments.

HIGH VOLTAGE SERVICE

Where service is delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the Demand Charge will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where service is delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the Energy Charge will also be subject to a discount of 0.350¢ per kWh of Energy.

High voltage service shall not be available from the Low Voltage Network Area as designated by Company.

LARGE LIGHT AND POWER SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

DETERMINATION OF THE BILLING DEMAND

Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, except that the Billing Demand will not be less than the lower of:

a) 75% of the greatest adjusted demand during the preceding eleven months, or
b) The greatest adjusted demand during the preceding eleven months minus 100 kW.

LARGE LIGHT AND POWER SERVICE

However, the Billing Demand shall not be less than the minimum demand specified in the customer's contract.

Demand will be adjusted by multiplying by 85% (90% effective December 1, 2019) and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% (90% effective December 1, 2019) lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

RATE CODES

73

APPLICATION

To the electric service requirements of a customer requiring service for no less than 2,000 kW and no more than 50,000 kW of connected load, where such electric service requirements are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at the voltage level specified in customer's contract.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Light and Power Service Rate Schedules 75 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Light and Power Service Rate Schedules 75 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE LIGHT AND POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

3. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SERVICE

RATE CODES

74

APPLICATION

The Large Power Service Schedule ("LP Schedule") applies to electric service delivered from existing Company facilities of adequate type and capacity, where Customer and Company have executed an Electric Service Agreement ("ESA") agreeing to the purchase and sale of Large Power Service and supplementing the terms and conditions of Large Power Service set forth in this LP Schedule.

Service under this LP Schedule is also subject to Company's Electric Service Regulations as well as all riders and other tariffs applicable to Large Power Service.

Customer shall not be entitled to purchase any service from the Company under this LP Schedule for purposes of resale to any other entity or to the Company.

ELECTRIC SERVICE AGREEMENTS

Every ESA and every amendment or modification of an ESA must be approved by the Minnesota Public Utilities Commission ("Commission") as a supplemental addition to this LP Schedule.

At a minimum, every ESA shall include the following:

(a) The connection point(s) of Company's and Customer's equipment at which Customer takes service ("Points of Delivery");
(b) The voltage level(s) at which service will be supplied;
(c) A method for determining Firm Demand (as defined below) in each month of the term of the ESA;
(d) An Incremental Production Service Threshold as defined in the Rider for Large Power Incremental Production Service, as applicable;
(e) A confidentiality agreement; and
(f) Any terms or conditions that differ from or are additional to the terms and conditions specified in this LP Schedule or in any rider or tariff applicable to Large Power Service.

Unless otherwise specifically approved by the Commission, each ESA shall have an initial minimum term of ten (10) years and shall continue in force until either party gives the other party written notice of cancellation at least four years prior to the time such cancellation shall be effective.

The effective date of each ESA shall be subject to approval by the Commission.

No Commission approval of any ESA shall act to prevent the Commission from later increasing or decreasing any of the rates or charges contained in this LP Schedule, any Rider or any other tariff applicable to Large Power Service. Nor shall any Commission approval of any ESA exempt any Customer from the applicability of any such increased or decreased charges.

An ESA shall be binding upon the Company and the Customer and their successors and assigns, on and after the effective date of the ESA; provided, however, that neither party may assign that ESA or any rights or obligations under the ESA without the prior written consent of the other party, which consent shall not unreasonably be withheld.

Inasmuch as all ESAs will contain confidential information with respect to Customer electric usage levels and other proprietary information of both the Customer and the Company ("Confidential Information"), all ESAs are to be marked as trade secret in their entirety for purposes of the Minnesota Government Data Practices Act. For this purpose, Confidential Information includes all disclosures, information and materials, whether oral, written, electronic or otherwise, relating to the business of either the Customer or the Company, that is not generally available to the trade or the public. The ESA may specifically expand this definition to ensure Customer-specific and/or Company-specific protections are in place. Because use and disclosure of Confidential Information requires a written agreement, the Company and the Customer will agree to such use and disclosure in each ESA.

For purposes of ESAs capitalized terms used in this LP Schedule shall have the same meaning as capitalized terms in the ESA.

For purposes of ESAs, the term "Holidays" shall mean New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas Eve Day, Christmas Day, and New Year's Eve Day.

For purposes of ESAs, the term "Office" shall mean the Minnesota Office of Energy Security or its successor organization.

TYPE OF SERVICE

Unless otherwise agreed in an ESA, Large Power Service shall be three phase, 60 hertz, at Company's available transmission voltage of at least 115,000 volts. Customer may specifically request to take all or any portion of its Large Power Service at Company's available high voltage of 13,000 through 69,000 volts, and such lower voltage deliveries may be subject to a Service Voltage Adjustment as described below.

LARGE POWER SERVICE

BASE RATES (MONTHLY)

The following charges (as modified by the Adjustments described below) shall apply to all service under this LP Schedule and the ESAs (collectively, the "Base Rates"):

Demand Charge

A single application for the first 10,000 kW or less of Firm Demand	$250,087
All additional kW of Firm Demand ($/kW)	$24.96

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.041¢

Excess Energy Charge

All kWh of Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost as described more fully in paragraphs 2 and 3 under "ENERGY."

ADJUSTMENTS

Company may modify Base Rates by the following adjustments:

1. Interim Rate Adjustment. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. Service Voltage Adjustment. Unless otherwise agreed in the ESA, where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, Company will increase the Demand Charge by $1.75 per kW of Firm Demand for that portion of Firm Demand taken at 13,000 through 69,000 volts.

3. Fuel and Purchased Energy Adjustment. A fuel and purchased energy adjustment will be determined in accordance with the Rider for Fuel and Purchased Energy Adjustment and a conservation program.

4. Conservation Adjustment. Adjustment will be determined in accordance with the Rider for Conservation Program Adjustment.

5. Transmission Adjustment. A transmission investment adjustment will be determined in accordance with the Rider for Transmission Cost Recovery.

6. Renewable Resource Adjustment. A renewable resources adjustment will be determined in accordance with the Rider for Renewable Resources.

7. CARE Low-Income Affordability Program Surcharge: There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

8. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

9. Taxes and Assessments. An adjustment for the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

10. Franchise Fee. An adjustment for customers located within the corporate limits of the applicable city as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the sum of kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month.
The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

DEMAND

1. Firm Demand. The Customer's ESA specifies the amount of Firm Demand in any billing month. In general, the Firm Demand will be based on amount specified, selected, nominated, determined or agreed upon in the Customer's ESA. Regardless of how the ESA describes or calculates the Customer's contractual demand in any billing month for purposes of applying the Demand Charge, this a mount shall be deemed to be the

LARGE POWER SERVICE

Customer's Firm Demand for purposes of this LP Schedule and the application of the Demand Charge.

2. Demands in Excess of Firm Demand. Company will endeavor to serve Customer requirements for power in excess of Firm Demand, but Company has no responsibility or liability whatsoever for failing to provide any power in excess of Firm Demand.

DEMAND NOMINATIONS

1. Demand Nomination increases. For all Customers who notify the Company periodically throughout the year per the terms of their respective ESAs, need to be made by the last business day excluding weekends and Holidays prior to the nominating deadlines specified in the Customers' ESAs. This provision shall supersede all references to all language in Customers' ESAs relating to nomination notice deadlines.

ENERGY

1. Firm Energy. Firm Energy shall mean the total electric consumption of the Customer measured in kilowatt-hours ("kWh") in each hour of the billing month, regardless of whether it is taken during peak or off peak hours, but limited to no more than the Customer's Firm Demand in any hour. In general, the amount of Firm Energy billed in each hour of the billing month will be equal to the amount of Firm Demand in that month unless modified by terms in the Customer's ESA.

2. Excess Energy. Excess Energy shall be the kWh of energy taken by Customer in each hour of the month in excess of the allowable Firm Energy levels specified in the Customer's ESA in that hour, unless the Customer takes such energy under the Rider for Large Power Incremental Production Service or another Rider applicable to Large Power Service and available to the Customer pursuant to its ESA.

3. Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy. Company's Incremental Energy Cost will be the highest cost energy after assigning lower cost energy to: all firm retail and wholesale customer requirements; all intersystem (pool) sales that involve capacity on a firm or participation basis; and all interruptible sales to Large Power, Large Light and Power, and General Service customers; but not including sales for Incremental Production Service.

PAYMENT

All bills for Large Power Service are due and payable at any office of Minnesota Power 15 days following the date the Company renders the bill or such later date as may be specified on the bill unless the Customer is subject to the Rider for Expedited Billing Procedures—Large Power Class or Customer specifically agrees to be subject to the Rider for Expedited Billing Procedures—Large Power Class in the ESA. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If Company does not receive payment on or before the due date printed on the bill, the bill shall be past due and delinquent.

LARGE POWER SURCHARGE

For new customers with Firm Demand in excess of 50,000 kW in any twenty-four month period, or for existing customers with increases in Firm Demand of more than 50,000 kW in any twenty-four month period, the additional Firm Demand in excess of 50,000 kW will be subject to a Large Power Surcharge. The Company will assess the Large Power Surcharge for a period of five years from the date the Customer executes a binding Commitment Agreement to take the power. The Large Power Surcharge will cover the additional cost to Company of obtaining the necessary power supply. The Large Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below. If the sum is negative then the Large Power Surcharge shall be zero.

Capacity Portion
For each kW of Firm Demand subject to surcharge Company shall add to the Demand Charge the excess of Company's Large Power Surcharge Supply Capacity Costs per kW over Company's Basic Capacity Cost. Company's Large Power Surcharge Supply Capacity Costs per kW will be: 1) Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor; 2) The Company’s estimated annual Revenue Requirements per kW associated with Company’s power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of the estimated annual Revenue Requirements associated with any such purchases or Company-owned power facilities which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Large Power Surcharge Supply Capacity Costs as soon the Company has made arrangements for the capacity and Company will advise Customer of the Company’s Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

LARGE POWER SERVICE

Energy Portion

For each kWh delivered to Customer subject to surcharge, Company shall add to the Energy Charge the excess of Company's Actual Large Power Surcharge Supply Energy Costs per kWh over the Company's Basic Energy Costs.

Company's Actual Large Power Surcharge Supply Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy: 1) Generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses; 2) Generated by and associated with Company's power production facilities added or refurbished to supply the power; or 3) A blend of the above costs if more than one source is used to supply the power. Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity and exclusive of energy provided by Company-owned power facilities covered by a Large Power Surcharge) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Large Power Surcharge Supply Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge may be applied.

Where the above surcharge is applicable to only a portion of the electric service taken at one point of delivery, the kWh subject to surcharge shall be the total kWh delivered in the month multiplied by the ratio of the Capacity subject to surcharge over the total Firm Demand at that point of delivery.

OPERATING PRACTICES

The Company shall employ operating practices and standards of performance in providing service under this LP Schedule that conform to those recognized as sound practices within the utility industry. In making deliveries of power under this LP Schedule, Company shall exercise such care as is consistent with normal operating practice by using all available facilities to minimize and smooth out the effects of sudden load fluctuations or other variance in voltage or current characteristics that may be detrimental to Customer's operations.

NON-CONTRACT LARGE POWER SERVICE

RATE CODES

78

APPLICATION

To the entire electric service requirements of 10,000 kW or more on customer's premises delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery for customers whose power requirements are of a relatively short-term nature or of a level of uncertainty which prevents long-term contractual commitment under the normally applicable terms and conditions for service under Company's Large Power Service Schedule.

Service hereunder is subject to Company's Electric Service Regulations and any applicable Riders.

TYPE OF SERVICE

Three phase, 60 hertz, at Company's available transmission voltage of 115,000 volts. Service may also be taken at Company's available high voltage of 13,000 through 69,000 volts subject to billing in conjunction with a Service Voltage Adjustment.

RATE (Monthly)

Demand Charge

For the first 10,000 kW or less of Non-Contract Billing Demand	$300,104
All additional kW of Non-Contract Billing Demand ($/kW)	$29.95

Energy Charge

All Firm Energy kWh (¢/kWh) (All On-Peak and Off-Peak)	1.014¢

All kWh of Non-Contract Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in accordance with the conditions set forth in paragraph 2 under "NON-CONTRACT ENERGY."

Plus any applicable Adjustments.

SERVICE VOLTAGE ADJUSTMENT

Where service delivery voltage is at Company's available high voltage of 13,000 through 69,000 volts, the Demand Charge will be increased by $2.10 per kW of Non-Contract Billing Demand.

NON-CONTRACT LARGE POWER SERVICE

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment. Such Fuel Adjustment shall be applicable to Customer's Non-Contract Firm Energy only.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

6. Solar Energy Adjustment: There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

MEASURED AND ADJUSTED DEMAND

The measured demand ("Measured Demand") in the month shall be the kW measured from all of the Points of Delivery specified in the ESA during the 15-minute period of Customer's greatest use during the month

The adjusted demand ("Adjusted Demand") in the month shall be the Measured Demand increased by one kilowatt for each 20 kvar of excess reactive demand. Excess reactive demand means the amount by which the maximum 15-minute measured kvar during the month exceeds 50% of the first 20,000 kW of Measured Demand plus 25% of all additional kW of Measured metered Demand.

This provision shall supersede all references to Metered Demand, Measured Demand, and Adjusted Demand in the Customers' ESAs.

NON-CONTRACT BILLING DEMAND

Non-Contract Billing Demand in the month is the greater of the current month's Measured Demand or the largest Measured Demand taken under Schedule 78 in the previous 12 months.

NON-CONTRACT ENERGY

1. Non-Contract Firm Energy in the month shall be the total kWh of energy taken by Customer in the month multiplied by the ratio of Non-Contract Billing Demand in the previous month to the current month's Measured Demand. Such ratio shall not exceed one.

2. Non-Contract Excess Energy shall be the kWh of energy taken by Customer in the billing month which is in excess of the Non-Contract Firm Energy. Such Excess Energy shall be billed at 110% of the Company's Incremental Energy Cost in month. Company's Incremental Energy Cost shall be determined each hour of the month and shall include fuel costs and variable operation and maintenance expenses for generating or purchasing the excess energy, and will be the highest cost energy after assigning lower cost energy to all firm retail and wholesale customer requirements, to all intersystem (pool) sales which involve capacity on a firm or participation basis, and to all economy and other similar transactions which may be entered into by Company from time to time.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

PURCHASED POWER SURCHARGE

When the Company does not have sufficient capacity to serve Customer's power requirements, a Purchased Power Surcharge will be assessed to cover the additional costs of purchasing such power provided Company is able to purchase and make available power for Customer's use. The Purchased Power Surcharge shall be the sum of a Capacity Portion and Energy Portion as described below, except if such sum is negative, then the Purchased Power Surcharge shall be zero.

Capacity Portion
For each kW of Non-Contract Billing Demand, there shall be added the excess of Company's Purchased Capacity Costs per kW over Company's Basic Capacity Cost. Company's Purchase Capacity Costs per kW will be Company's cost per kW as purchased from its power suppliers with appropriate adjustments for reserve requirements/replacement power, transmission losses and coincidence factor. Company's Basic Capacity Costs per kW will be Company's estimated annual Revenue Requirements associated with Company-owned power production facilities and with Company firm power purchases, exclusive of any such purchases which are covered by a Large Power Surcharge, divided by the aggregate coincidental kilowatts of all customer loads serviced by such generating capacity and purchased capacity, adjusted for estimated transmission losses and load coincidence factor.

Company will advise Customer of the Purchased Capacity Costs as soon as arrangements have been made for such capacity and Company will advise Customer of the Company's Basic Capacity Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

Energy Portion
For each kWh of Non-Contract Firm Energy delivered to Customer, there shall be added the excess of Company's Actual Purchased Energy Costs per kWh over the Company's Basic Energy Costs. Company's Actual Purchased Energy Costs per kWh will be determined monthly as Company's actual cost per kWh for the energy generated by and associated with the Purchased Capacity, adjusted for estimated transmission losses.

Company's Basic Energy Costs per kWh will be Company's estimated annual Revenue Requirements for fuel and associated operation and maintenance expenses at Company-owned power production facilities, and for energy associated with firm power purchases and economy purchases (but exclusive of all emergency and scheduled outage energy, and exclusive of any energy associated with Purchased Capacity) divided by the aggregate associated kilowatt-hours, adjusted for estimated transmission losses.

Company will advise Customer of the approximate Purchased Energy Costs and Company's Basic Energy Costs 30 days prior to the beginning of each calendar year in which the surcharge will be applied.

SERVICE CONDITIONS

Service is available under this Schedule to customers who otherwise qualify but who elect not to take service under Company's Large Power Service Schedule 74 for which a ten

NON-CONTRACT LARGE POWER SERVICE

(10) year contract term and at least a four (4) year contract cancellation provision are required by Company. Such service shall be subject to all provisions of this Schedule. The initial Non-Contract Demand of Power (Initial Demand) for such an electric service agreement shall be the Measured Demand which Customer established during the first full month of service.

A customer taking service on Schedule Non-Contract Large Power Service 78 may not take service from Schedule 74 without a one (1) year written notice to Company, unless the Company agrees otherwise. Additionally, unless Company has agreed otherwise, customers who have given notice of cancellation of a contract for service on Large Power Service Schedule 74 and have chosen to reinstate that contract less than 12 months prior to the effective date of cancellation shall receive service under this schedule. Such service will be provided from the effective date of the reinstatement and will continue until 12 months have elapsed from the date the reinstatement was executed.

Company recognizes that Customer's demand may, from time to time, exceed the Initial Demand in the electric service agreement. Company will endeavor to serve demands in excess of the Initial Demand but assumes no responsibility or liability whatsoever for providing such service.

REGULATION AND JURISDICTION

Electric service shall be available from Company at the rates and under the terms and conditions set forth in the currently applicable rate schedule or other superseding rate schedules in effect from time to time.

All the rates and regulations referred to herein are subject to approval, amendment and change by any regulatory body having jurisdiction thereof.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

RATE CODES

79

APPLICATION

To the electric service requirements of a customer requiring 10,000 kW or more, where the electric service requirements of 10,000 kW or more are subject to effective competition. Specifically, a customer is subject to effective competition, per Minnesota Statutes, Section 216B.162, if the customer is located within the Company's assigned service area as determined under Minnesota Statutes, Section 216B.39, and if the customer has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Commission under Minnesota Statutes, Section 216B.16.

TYPE OF SERVICE

Three phase, 60 hertz at high voltage of 13,000 through 69,000 volts or at transmission voltage of 115,000 volts.

RATE

To be specified in customer's contract.

TERMS AND CONDITIONS

1. The minimum rate under this schedule shall recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

2. The maximum possible rate reduction under this rate schedule shall not exceed the difference between the Company's Large Power Service Rate Schedules 74 and the cost to the customer of the lowest cost competitive energy supply.

3. The term of a contract for a customer who elects to take service under this schedule must be no less than one year and no longer than five years.

4. The Company, within a general rate case, is allowed to seek recovery of the difference between the standard Large Power Service Rate Schedules 74 and the competitive rate times the usage level during the test year period.

5. A rate under this competitive rate schedule shall meet the conditions of Minnesota Statutes, Section 216B.03, for other customers in this same customer class.

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

6. A rate under this schedule shall not compete with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes, Section 216B.166, subdivision 2, paragraph (c).

7. A rate under this schedule may not be offered to a customer in which the Company has a financial interest greater than 50 percent.

8. The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the Minnesota Public Utilities Commission and upon the date specified. If the Commission does not approve the rate, Minnesota Power may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

REGULATION AND JURISDICTION

The Commission has the authority to approve, modify or reject a rate under this schedule. If the Commission approves the competitive rate, it becomes effective as agreed to by the Company and the customer. If the competitive rate is modified by the Commission, the Commission shall issue an order modifying the competitive rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the Commission's order becomes final. If either party rejects the Commission's proposed modification, the Company, on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to the bill the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

3. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

Filing Date November 1, 2021 **MPUC Docket No.** E015/GR-21-335
Effective Date January 1, 2022 **Order Date**

Approved by: David R. Moeller
David R. Moeller
Senior Attorney & Director of Regulatory Compliance

COMPETITIVE RATE SCHEDULE - LARGE POWER SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill. Payments must be received by Minnesota Power on or before such due date and shall not be considered as payment received until the funds are usable or collectible by Minnesota Power. If payment is not received on or before the due date printed on the bill, the bill shall be past due and delinquent.

OUTDOOR AND AREA LIGHTING SERVICE

RATE CODES

Outdoor Lighting Service	76
Area Lighting Service	77

APPLICATION

To all classes of retail customers for outdoor lighting purposes (Rate Codes 76) and to persons other than governmental subdivisions for the purpose of lighting streets, alleys, roads, driveways and parking lots (Rate Code 77) subject to any applicable Riders. Rate Code 76 is not available on a seasonal or temporary basis.

RATE

Lamp Type & Size	CIS Code	Rate Per Lamp Per Month Option 1	Option 2	Option 3	Option 4
Sub rate code		_ _A	_ _B	_ _C	_ _D
			(Option 2 Closed to New Installation)	(Option 3 Closed to New Installation)	
Mercury Vapor Lamps (Closed to New Installation)					
7,000 Lumens (175 watts)	MV175W	$11.77	$8.23		
20,000 Lumens (400 watts)	MV400W	$18.73	$12.40		
55,000 Lumens (1,000 watts)	MV1000W	$34.89	$24.58		
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	SV100W	$10.32	$5.96	$5.96	
14,000 Lumens (150 watts)	SV150W	$11.90	$7.60		
23,000 Lumens (250 watts)	SV250W2	$16.88	$10.12	$10.19	
45,000 Lumens (400 watts)	SV400W	$22.60	$14.89	$10.81	
Metal Halide Lamps					
17,000 Lumens (250 watts)	MH250W	$16.69			
28,800 Lumens (400 watts)	MH400W	$20.33		$12.05	
88,000 Lumens (1,000 watts)	MH1000W	$33.87		$22.00	
Light Emitting Diodes (LED)					
4,674 Lumens (48 watts or less)	LED48W	$9.00			
10,000 Lumens (71 watts or less)	LED71W	$12.02			
24,000 Lumens (184 watts or less)	LED184W	$18.16			
46,800 Lumens (320 watts or less)	LED320W	$26.12			

Filing Date November 1, 2021 **MPUC Docket No.** E015/GR-21-335
Effective Date January 1, 2022 **Order Date**

Approved by: David R. Moeller
David R. Moeller
Senior Attorney & Director of Regulatory Compliance

OUTDOOR AND AREA LIGHTING SERVICE

Pole Charge					
Each pole used for service under this schedule only	MPPOLE	$10.50	$10.50	$10.50	
Monthly Service Charge		Included	Included	Included	$3.34
Energy Charge - Per kWh		Included	Included	Included	5.990

Plus any applicable adjustments

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

   The monthly fuel and purchased energy adjustment per lamp shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per lamp shown in the Energy Table below for the respective lamps.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

7. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

OUTDOOR AND AREA LIGHTING SERVICE

8. Bills for service within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	Daily Estimates	4,200	462	379	367	302	264	233	252	294	336	401	435	475
Monthly kWh usage per fixture by type														
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH250W	3	1,260	139	114	110	91	79	70	76	88	101	120	130	142
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MH1000W	12	4,410	485	398	385	317	277	245	264	309	353	421	457	499
LED48W	1	207	23	19	18	15	13	11	12	14	17	20	21	24
LED71W	1	298	33	27	26	21	19	17	18	21	24	28	31	34
LED184W	2	773	85	70	68	56	49	43	46	54	62	74	80	87
LED320W	4	1,344	148	121	117	97	84	75	81	94	108	128	139	152

Company shall furnish all electric energy required for service under this schedule.

OUTDOOR AND AREA LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customer must select Option 1 or Option 4 only for each account served under this schedule.

Option 1
COMPANY TO OWN AND MAINTAIN:

1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, lamp, ballast, photo-electric control and wiring.

Option 2

1. The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include, but not be limited to, the fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications.

2. The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option, including poles, except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls Option 2 is closed to new installations.

Option 3

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's pole or pad-mounted transformer. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications. Customer is responsible for providing lighting poles.

2. The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. No maintenance will be provided by the Company on Customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

OUTDOOR AND AREA LIGHTING SERVICE

Option 4
CUSTOMER TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's electrical system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications. Company's point of delivery shall be on the Company's side of disconnect switch either at the weather head for overhead service or at the pad mount transformer for underground service.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of delivery. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen.

2. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

3. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

4. For Area Lighting Service purposes, no more than four lights will be mounted on a single distribution pole used for other utility purposes. If more than one light is mounted on a single pole, Company's investment in additional facilities, over and above those which

OUTDOOR AND AREA LIGHTING SERVICE

would be required for a single standard bracket mounting, shall not exceed $15.00 per light. Additional required investment will be at Customer's expense.

5. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Area Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For lamps which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Materials charges per the Company's cost for lighting replacement equipment plus the then current Material Handling Expense and A&G expense per Company's Accounting Manual.

MUNICIPAL PUMPING

RATE CODES

87

APPLICATION

To electric service supplied to a municipality for the operation of water pumping and sewage disposal facilities, where all such facilities are completely electrified and operated by service of Company, subject to Company's Electric Service Regulations and any applicable Riders. Service shall be delivered at one point from existing facilities of adequate type and capacity and metered at (or compensated to) the voltage of delivery.

Service under this Schedule is closed to new customers. Existing customer(s) shall be gradually transitioned to an alternative applicable Rate Schedule.

TYPE OF SERVICE

Single phase, three phase or single and three phase, 60 hertz, at one standard low voltage of 120/240 to 4160 volts; except that within the Low Voltage Network Area service shall be three phase, four wire, 60 hertz, 277/480 volts.

RATE (Monthly)

CUSTOMERS WITHOUT A DEMAND METER	
Service Charge	$12.00
Energy Charge	
All kWh (¢/kWh)	8.639¢
CUSTOMERS WITH A DEMAND METER	
Service Charge	$12.00
Demand Charge	
All kW ($/kW)	$6.50
Energy Charge	
All kWh (¢/kWh)	6.054¢

Plus any applicable Adjustments.

MUNICIPAL PUMPING

MINIMUM CHARGE (Monthly)

Demand Charge per kW of Billing Demand but not less than the Minimum Demand specified in customer's contract.

Plus any applicable Adjustments.

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

4. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

5. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

6. There shall be added to the monthly bill, as computed above, a Low-Income Affordability Program Surcharge determined in accordance with the Pilot Rider for Customer Affordability of Residential Electricity (CARE).

7. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service to Municipalities within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for the city's Franchise Fee.

MUNICIPAL PUMPING

HIGH VOLTAGE SERVICE

Where customer contracts for service delivered and metered at (or compensated to) the available primary voltage of 13,000 volts or higher, the monthly bill, before Adjustments, will be subject to a discount of $2.00 per kW of Billing Demand. In addition, where customer contracts for service delivered and metered at (or compensated to) the available transmission voltage of 115,000 volts or higher, the monthly bill, before Adjustments, will also be subject to a discount of 0.350¢ per kWh of Energy.

DETERMINATION OF BILLING DEMAND

The Billing Demand is the kW measured during the 15-minute period of customer's greatest use during the month, as adjusted for power factor, but not less than 5 kW.

Demand will be adjusted by multiplying by 85% (90% effective December 1, 2019) and dividing by the average monthly power factor in percent when the average monthly power factor is less than 85% (90% effective December 1, 2019) lagging. However, in no event shall the average monthly power factor used for calculation in this paragraph be less than 45%.

Maximum use created by the operation of fire pumps will be disregarded if Company is notified promptly.

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

CONTRACT PERIOD

Five years, automatically renewable for one year periods unless canceled by 30 days' written notice by either party to the other prior to any renewal date.

STREET AND HIGHWAY LIGHTING SERVICE

RATE CODES

Highway Lighting Service	80
Overhead Street Lighting Service	83
Ornamental Street Lighting Service	84

TERRITORY

Applicable in all territories served at retail by the Company. Highway Lighting Service is subject to individual review for each point of delivery.

APPLICATION

To any governmental subdivision taking all of its street or highway lighting requirements for service within the Company's service territory under the Company's standard contract for such service, subject to any applicable Riders. Highway Lighting Service is limited to the State of Minnesota, Department of Highways exclusively for public highway lighting.

RATE

Lamp Type & Size	CIS Code	Rate Per Fixture Per Month Option 1	Option 2	Option 3	Option 4
Sub rate code		_ _A	_ _B	_ _C	_ _D
			(Option 2 Closed to New Installation)	Option 3 Closed to New Installation)	
Mercury Vapor Lamps (Closed to New Installations)					
7,000 Lumens (175 watts)	MV175W	$16.25	$9.70	$8.10	
10,000 Lumens (250 watts)	MV250W			$10.29	
20,000 Lumens (400 watts)	MV400W	$22.10	$15.00	$13.90	
55,000 Lumens (1,000 watts)	MV1000W2			$25.00	
Sodium Vapor Lamps					
8,500 Lumens (100 watts)	SV100W	$14.35	$7.62	$6.50	
14,000 Lumens (150 watts)	SV150W	$15.88	$8.92	$9.15	
14,000 Lumens (150 watts)	SV150W-P			$8.30	
20,500 Lumens (200 watts)	SV200W	$19.65	$12.06	$10.00	
23,000 Lumens (250 watts)	SV250W	$19.78	$12.70	$10.80	
45,000 Lumens (400 watts)	SV400W	$24.30	$17.98	$13.00	
Metal Halide Lamps					
28,800 Lumens (400 watts)	MH400W		$15.90		
Light Emitting Diode (LED)					
4,000 Lumens (54 watts or less)	LED54W	$13.60			
8,800 Lumens (118 watts or less, but more than 54 watts)	LED118W	$18.10			

STREET AND HIGHWAY LIGHTING SERVICE

23,000 Lumens (219 watts or less, but more than 118 watts)	LED219W	$22.50			
30,000 Lumens (278 watts or less)	LED278W	$22.50			
Monthly Service Charge	Included	Included	Included	$3.34	
Energy Charge - Per kWh	Included	Included	Included	5.990¢	
Plus any applicable adjustments					

ADJUSTMENTS

1. The following Interim Adjustment shall be applied to billings for electric service:

   There shall also be added an Interim Rate Adjustment equal to 14.23% of the billing for electric service.

2. There shall be added to or deducted from the monthly bill, as computed above, a fuel and purchased energy adjustment determined in accordance with the Rider for Fuel and Purchased Energy Adjustment.

3. The monthly fuel and purchased energy adjustment per fixture shall be determined as the above fuel and purchased energy adjustment per kWh multiplied by the monthly kWh per fixture shown in the Energy Table below for the respective fixtures.

4. There shall be added to the monthly bill, as computed above, a transmission investment adjustment determined in accordance with the Rider for Transmission Cost Recovery.

5. There shall be added to the monthly bill, as computed above, a renewable resources adjustment determined in accordance with the Rider for Renewable Resources.

6. There shall be added to the monthly bill, as computed above, a conservation program adjustment determined in accordance with the Rider for Conservation Program Adjustment.

7. There shall be added or deducted from the monthly billing, as computed above, a solar energy adjustment determined in accordance with the Rider for Solar Energy Adjustment.

8. Plus the applicable proportionate part of any taxes and assessments imposed by any governmental authority which are assessed on the basis of meters or customers, or the price of or revenues from electric energy or service sold, or the volume of energy generated, transmitted or purchased for sale or sold.

9. Bills for service to parties within the corporate limits of the applicable city shall include an upward adjustment as specified in the applicable Rider for city's Franchise Fee.

STREET AND HIGHWAY LIGHTING SERVICE

PAYMENT

Bills are due and payable 15 days following the date the bill is rendered or such later date as may be specified on the bill.

BURNING SCHEDULE

Burning schedule is from dusk until dawn each night for a total of approximately 4,200 hours per year.

ENERGY TABLE

Lamp CIS Code	Days Month		31	28	31	30	31	30	31	31	30	31	30	31
		Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Burning Hours	Daily Estimates	4,200	462	379	367	302	264	233	252	294	336	401	435	475
	Montly kWh usage per fixture by type													
MV175W	2	888	98	80	78	64	56	49	53	62	71	85	92	100
MV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
MV400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
MV1000W2	13	4,620	508	417	404	332	290	256	277	323	370	441	479	523
SV100W	1	504	56	46	44	36	32	28	30	35	40	48	52	57
SV150W	2	756	83	68	66	54	48	42	45	53	60	72	78	87
SV150W-P	1	468	51	42	41	34	29	26	28	33	37	45	48	54
SV200W	3	1,140	125	103	100	82	72	63	68	80	91	109	118	129
SV250W	3	1,224	135	110	107	88	77	68	73	86	98	117	127	138
SV400W	6	2,016	222	182	176	145	127	112	121	141	161	192	209	228
MH400W	5	1,932	213	174	169	139	121	107	116	135	155	184	200	219
LED54W	1	226	25	20	20	16	14	13	14	16	18	22	23	25
LED118W	1	505	56	46	44	36	32	28	30	35	40	48	52	58
LED219W	3	945	104	85	83	68	59	52	57	66	76	90	98	107

Company shall furnish all electric energy required for service under this schedule.

STREET AND HIGHWAY LIGHTING SERVICE

EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

New Customers with new installations must select Option 1 or Option 4 only for each account served under this schedule. Options 2 and 3 are closed to new installations. Options 1 or 4 are available for Overhead Lighting Service and for Highway or Ornamental Lighting Service.

Option 1
COMPANY TO OWN AND MAINTAIN.
1. The Company shall install, own, operate and provide normal maintenance to all equipment necessary for the above service including the Lighting Equipment beyond the point of attachment to Company's facilities consisting of, but not limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, fixture, ballast, photo-electric control, driver, and wiring.

Option 2

The Customer shall own all equipment for service under this schedule beyond the point of attachment with Company's facilities. The equipment shall include, but not be limited to, the fixture, standard brackets or mast arms not exceeding 14 feet in length, lamp, ballast, photo-electric control and all minor materials. All customer-owned equipment must meet Company's specifications. In all cases, poles are owned by Company.

The Company shall install and operate all equipment necessary for service under this schedule and Company will own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. All Customer owned Lighting Equipment will be installed at Customer's expense. The Company shall perform all normal maintenance on equipment necessary for service under this schedule and furnish and replace all burned out lamps and photo-electric controls. Option 2 is closed to new installations.

Option 3

The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include, but not be limited to, the posts, fixture, mounting bracket, lamp, ballast and all minor materials. In addition, Customer must furnish and install a master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. All Customer owned equipment must meet Company's specifications.

The Company shall own all equipment necessary for service under this Option except for that equipment as specified in paragraph 1. The Company will furnish and replace all burned

STREET AND HIGHWAY LIGHTING SERVICE

out lamps and photo-electric controls and will clean or replace glassware at the time of lamp replacement. Customer shall be responsible for providing replacement glassware. No maintenance will be provided by the Company on customer owned equipment except as specified in a separate agreement. Option 3 is closed to new installations.

Option 4
CUSTOMERS TO OWN AND MAINTAIN:

1. The Customer shall own, install and maintain all equipment necessary for service under this schedule beyond the point of attachment with Company's lines used to deliver power to Customer's system. The equipment shall include but not be limited to the poles, fixture, mounting bracket, lamp, ballast, photo-electric control and all minor materials. In addition, Customer must furnish and install in master disconnect switch at the point of attachment to isolate Customer's equipment from Company's electrical system. Customer's disconnect switch must meet Company's specifications.

2. Customer is responsible for all maintenance on all equipment beyond Company's point of attachment. Standard safety procedures followed by the Company on Company-owned lighting facilities shall be followed by Customer when maintaining its lighting equipment. Company reserves the right to disconnect Customer equipment from Company's electrical system if in the Company's opinion Customer's lighting equipment is operated or maintained in an unsafe or improper condition.

CONTRACT PERIOD

Six months, automatically renewable for six month periods unless canceled by 30 days written notice by either party to the other.

SERVICE CONDITIONS

1. Customers will contract for service under this schedule for the number of fixtures of each size installed at the time of the contract.

2. Lights shall be located at sites designated and authorized by Customer. Customer shall provide in writing suitable right-of-way and right-of-occupancy for the facilities which the Company deems necessary to render service under the option chosen. The location shall be readily accessible to Company's equipment used for servicing and/or supplying service under the option chosen. The Company shall have the right to use and occupy the street and highway rights-of-way for the purpose of performing any act of service in connection with service under this schedule.

3. Service will normally be from standard distribution facilities typical of those in the area surrounding the point of service. If it is necessary to provide non-standard distribution facilities, Customer shall pay Company for all costs in excess of standard facility costs.

STREET AND HIGHWAY LIGHTING SERVICE

4. Company will, at Customer's expense, relocate or change the position of any poles, circuits or lights owned by the Company as may be requested in writing and duly authorized by Customer.

5. Company will install at its expense such additional street lights served under Option 1 as may be requested in writing and duly authorized by Customer from time to time during the period of the contract. Company shall provide as standard a service extension of up to the equivalent of one pole span to provide service under this schedule without cost to the Customer. No additional transformer capacity shall be provided as standard for Option 4 Lighting Service. All necessary costs for providing service under this schedule in excess of standard costs shall be paid by Customer.

6. For fixtures which satisfy the conditions as set forth in Options 1 or 2 under Equipment Ownership, Operation and Maintenance, Company will absorb the cost of replacing a lamp and photo-electric control devices damaged by a first act of vandalism at each location during each calendar year. In addition, Company will absorb the cost of replacing a lighting unit damaged by a first act of vandalism at each location during each calendar year if served under Option 1.

7. All subsequent and other costs due to vandalism are at Customer's expense. For those locations served under Option 1 or 2, Company will repair equipment (not covered above) damaged by vandalism and will bill customer for appropriate costs.

8. Existing Option 1 Customers who wish to replace Sodium Vapor fixtures that are less than ten years old and not in need of significant maintenance or repair with LED street lights will pay Company the remaining un-depreciated facility cost. Under Option 2, Customers who convert to LED street lights will be assessed a removal fee of $50 if the mast arm is left up and reused or $100 if the mast arm is removed and not reused. Under Option 3, the Company’s Compatible Unit Estimator (CUE) will be used to estimate the removal fee with a true-up of actual costs once the work is completed.

SCHEDULE OF CHARGES

Applicable in conjunction with Service Conditions paragraph 6.

Labor and vehicle charges per the applicable rate as stated in the Company's Accounting Manual at the time the charge was incurred. Charges for materials used per the Company's cost for lighting replacement equipment plus the then current Materials Handling expense and A&G expense per Company's Accounting Manual.

Notice to:
COUNTIES AND MUNICIPALITIES

Under Minn. Stat. § 216B.16, Subd. 1

minnesota power

AN ALLETE COMPANY

On XXXX XX, 20XX, the Minnesota Public Utilities Commission ("Commission") accepted as of XXXX XX, 2021, Minnesota Power's application for a general increase in rates for electric service provided to customers in the State of Minnesota of approximately $108.3 million, or about 17.58%, pursuant to Minn. Stat. § 216B.16.

In accordance with Minn. Stat. § 216B.16, subd. 2, the Commission has suspended proposed final rates to allow the Commission time to evaluate the application. In accordance with Minn. Stat. § 216B.16, subd. 3, the Commission has authorized a total interim rate increase of approximately $87.3 million or about 14.23% to be effective XXXX XX, 2022. During this interim period, Minnesota Power electric customers' bills will be approximately 14.23% higher depending on service class, and the rates will remain in effect until a final rate level is determined.

Examples of the effect of these increases on typical bills are as follows:

Proposed change in monthly electricity costs

Customer Classification	Avg. monthly kWh usage	Previous monthly cost	Interim monthly increase	Proposed final monthly increase*
Residential	701	$82.76	$11.78	$15.08
Residential Dual Fuel	1,013	$94.04	$13.38	-$0.42
General Service	2,581	$301.93	$42.96	$55.09
Commercial & Industrial Dual Fuel	3,654	$324.01	$46.11	$1.85
Large Light & Power	247,815	$21,772.72	$3,098.26	$3,938.50
Large Power	51,654,952	$3,635,297.83	$517,302.88	$558,488.32
Street & Area Lighting	224	$60.95	$8.67	$11.11

*Monthly increases include all line items on bills except sales taxes and municipal franchise fees, and may vary by individual customer based on usage characteristics.

The rate levels upon which the previous monthly costs are based were authorized in Docket No. E-015/GR-16-664.

The Commission will determine the amount of increase in rates it will allow in late 2022, and final rates reflecting that determination will be implemented thereafter. If the final rate level is less than the interim rate level, the amount collected during the interim period attributable to that difference will be refunded to customers with interest.

The proposed rate schedules and a comparison of present and proposed rates may be examined by the public during normal business hours at the Minnesota Department of Commerce, 85 7th Place East, Suite 280, St. Paul, MN 55101, Telephone: 651-539-1500

They are also available on the Internet at:

Minnesota Power: www.mnpower.com/RateReview

Commission: www.mn.gov/puc
Docket Number E-015/GR-21-335

The Minnesota Department of Commerce, among other parties, will review Minnesota Power's books and records in this proceeding.

An Administrative Law Judge will schedule public hearings. Customers will be notified when the hearings are scheduled. Public notice of hearing dates and locations will be published in local newspapers in Minnesota Power's service area.

Persons who wish to formally intervene or testify in this case should contact the Administrative Law Judge, Minnesota Office of Administrative Hearings, 600 North Robert St., St. Paul, MN 55101.

Submit comments

Minnesota Public Utilities Commission

121 7th Place East, Suite 350
St. Paul, MN 55101-2147
651-296-0406 or 1-800-657-3782

mn.gov/puc

Select "Tell us what you think" and enter the docket (21-335) with your comments.

Email comments to consumer.puc@state.mn.us

How to learn more

Minnesota Power's current and proposed rate schedules are available at:

Minnesota Power

www.mnpower.com/RateReview
800-228-4966

Minnesota Department of Commerce

Energy Division
85 7th Place East, Suite 280
St. Paul, MN 55101
651-539-1500

mn.gov/puc
Select eDockets, then type 21 in the year field, type 335 in the number field, select Search, and the list of documents will appear on the next page.

Citizens with hearing or speech disabilities may call through their preferred Telecommunications Relay Service.

minnesota power
AN ALLETE COMPANY

mnpower.com/RateReview

21130 10.26.21

minnesota power
AN ALLETE COMPANY

Interim change in electric rates

Your Minnesota Power bill is changing.

Effective January 1, 2022

L-XXXXX

Minnesota Power has asked the Minnesota Public Utilities Commission (MPUC) for an increase in electricity rates.

The requested increase is about 17.58% or $108.3 million overall. While the MPUC reviews our request, state law allows Minnesota Power to collect higher rates on an interim (temporary) basis. The MPUC has approved an overall interim rate increase of about 14.23% or $87.3 million, for all Minnesota Power customers. The increase is effective for service rendered on or after January 1, 2022.

The rate increase appears on your bill as “Interim Rate Adjustment.” It applies to all major items on your bill. For residential and small general service customers, those charges include the monthly minimum charge and energy charges. For all other customers, the increase applies to the customer charge, energy charges, and the demand charge. The interim rate adjustment is billed as a 14.23% increase or about an additional $15.08 a month for the average residential customer.

The MPUC will have up to 15 months to review our request and will make its decision regarding final rates by late 2022. If final rates are lower than interim rates, Minnesota Power will refund customers the difference with interest. If final rates are higher than interim rates, Minnesota Power will not charge customers the difference.

Why is Minnesota Power asking for an increase?

Our current rates were set in MPUC Docket No. E015/GR-16-664. Since then we’ve invested in transmission, distribution and generation infrastructure and cleaner energy resources to ensure safe, reliable and cleaner sources of energy for customers. State regulators will review these expenses and decide how Minnesota Power may recover those costs.

What is the process for reviewing Minnesota Power’s request?

The MPUC, the Minnesota Department of Commerce – Division of Energy Resources, the Office of the Attorney General – Residential Utilities and Antitrust Division, public interest groups, and customers will review and investigate our proposal.

The MPUC will hold public hearings about our rate request. Customers and others will be able to comment on our rate request at the public hearings. You may add verbal comments, written comments, or both into the record.

Notice of the public hearing dates and locations will be published in local newspapers, in bill inserts and online at **www.mnpower.com/RateReview** and **mn.gov/puc**.

Here's how these rate changes will affect monthly bills

The proposed rate increase will affect individual monthly bills differently, depending on the amount of electric usage and customer type. The table below shows the average, interim and proposed rates for each customer type.

Customer Classification	Avg. monthly kWh usage	Avg. current monthly cost	Interim monthly increase	Proposed final monthly increase
Residential	701	$82.76	$11.78	$15.08
Residential Dual Fuel	1,013	$94.04	$13.38	-$0.42
General Service	2,581	$301.93	$42.96	$55.09
Commercial & Industrial Dual Fuel	3,654	$324.01	$46.11	$1.85
Large Light & Power	247,815	$21,772.72	$3,098.26	$3,938.50
Large Power	51,654,952	$3,635,297.83	$517,302.88	$558,488.32
Street & Area Lighting	224	$60.95	$8.67	$11.11

minnesota power

AN ALLETE COMPANY

RATE INCREASE NOTICE

XXXX 2022

Minnesota Power has asked the Minnesota Public Utilities Commission (MPUC) for permission to increase its electric rates by approximately $108.3 million, or about 17.58 percent overall. Depending on customer class and usage, the actual percent will vary based upon final approval by the MPUC. The MPUC will make its decision regarding final rates late 2022.

Public Comment

Administrative Law Judge ___________ has scheduled public hearings to give customers an opportunity to present their views regarding Minnesota Power's recently filed retail rate case (MPUC Docket No. E-015/GR-21-335 and OAH Docket No. ___). Any Minnesota Power customer or other person may attend or provide comments at the hearings. You are invited to comment on the adequacy and quality of Minnesota Power's service, the level of rates or other related matters. You do not need to be represented by an attorney.

Public Hearings Schedule

DATE Time Address 1 Address 2 Address 3	**DATE** Time Address 1 Address 2 Address 3
DATE Time Address 1 Address 2 Address 3	**DATE** Time Address 1 Address 2 Address 3

Written comments may be sent to Administrative Law Judge _______, Office of Administrative Hearings, PO Box 64620, St. Paul, MN 55164 or by email to _____________@state.mn.us. Written comments are most effective when they include: 1) the section of Minnesota Power's proposal you are addressing, 2) your specific recommendations, 3) the reason for your recommendations, 4) Docket No. OAH _____ and MPUC E015/GR-21-335.

Important: Comments will be made available to the public on the MPUC website, except in limited circumstances consistent with the Minnesota Government Data Practices Act. The MPUC does not edit or delete personal identifying information from submissions.

Accommodations

If you need any reasonable accommodation to enable you to fully participate in these public hearings (i.e., sign language or foreign language interpreter, wheelchair accessibility, or large-print materials), please contact the Office of Administrative Hearing at 651-361-7834 at least one week in advance of the meeting.

Evidentiary Hearings

Formal evidentiary hearings on Minnesota Power's proposal are scheduled to start on xxx,xx,20xx, at xx:xx x.m., in the Large Hearing Room, Minnesota Public Utilities Commission, 121 Seventh Place East, Suite 350, St. Paul, MN. The purpose of the evidentiary hearings is to allow Minnesota Power, the Minnesota Department of Commerce–Division of Energy Resources, the Office of Attorney General–Residential Utilities and Antitrust Division and others to present testimony and to cross-examine each other's witnesses on the proposed rate increase.

Anyone who wishes to formally intervene in this case should contact the Administrative Law Judge, _______, at the Office of Administrative Hearings, PO Box 64620, St. Paul, MN 55164 or by email to _______@state.mn.us.

Effect of Rate Changes

Below are examples of the effect of the proposed increase on typical bills of Minnesota Power's customers. Individual changes may be higher or lower depending on actual electricity usage.

Customer Classification	Avg. monthly kWh usage	Previous monthly cost	Interim monthly increase	Proposed final monthly increase*
Residential	701	$82.76	$11.78	$15.08
Residential Dual Fuel	1,013	$94.04	$13.38	-$0.42
General Service	2,581	$301.93	$42.96	$55.09
Commercial & Industrial Dual Fuel	3,654	$324.01	$46.11	$1.85
Large Light & Power	247,815	$21,772.72	$3,098.26	$3,938.50
Large Power	51,654,952	$3,635,297.83	$517,302.88	$558,488.32
Street & Area Lighting	224	$60.95	$8.67	$11.11

*****Monthly increases include all line items on bills except sales taxes and municipal franchise fees, and may vary by customer based on usage.

The rate changes described in this notice have been requested by Minnesota Power. The MPUC may either grant or deny the requested changes, in whole or in part, and may grant a lesser or greater increase than that requested for any class or classes of service.

For More Information

You may examine our current and proposed rate schedules and our request for new rates by visiting our website at www.mnpower.com/RateReview. Or, you may contact the Minnesota Department of Commerce–Energy Division at 85 7th Place East, Suite 280, St. Paul, MN 55101, Phone: 651-539-1500. Customers with hearing or speech disabilities may call through Minnesota Relay 800-627-3529 or 7-1-1. Web: mn.gov/puc (search by docket number: select 21 in the year field, enter 335 in the number field, click on search, and the list of documents will appear on the next page).

Customers may submit comments with the MPUC:

Online: Visit mn.gov/puc, select "Tell us what you think," find this docket (21-335), and add your comments to the discussion.

Mail: 121 7th Place East, Suite 350, St. Paul, MN 55101

Phone: 651-296-0406 or 1-800-657-3782
Customers with hearing or speech disabilities may call through Minnesota Relay 1-800-627-3529 or 7-1-1.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E015/GR-21-335

AGREEMENT AND UNDERTAKING

Minnesota Power, in conjunction with the Notice and Petition for Interim Rates filed with the Minnesota Public Utilities Commission ("Commission"), makes the following unqualified agreement concerning refunding any portion of the requested increase in rates determined by the Commission to be unreasonable.

Pursuant to Minn. R. 7825.3300, Minnesota Power hereby agrees and undertakes to refund to its customers the amount, if any, collected during the interim rate period, plus interest at the current rate determined by the Commission, computed from the effective date of the interim rates through the date of refund. The refund shall be made in accordance with Minn. Stat. § 216B.16, subd. 3, and in a manner approved by the Commission.

In addition, Minnesota Power agrees to keep such records of sales and billings under the proposed interim rates as will be necessary to compute any potential refund.

This Agreement and Undertaking is made pursuant to authority granted by the Board of Directors of ALLETE, Inc.

Dated: November 1, 2021

Respectfully submitted,

Patrick L. Cutshall

Patrick L. Cutshall
ALLETE Vice President & Corporate Treasurer
30 West Superior Street
Duluth, MN 55802
218-355-3529

Subscribed to before me this 1st day of November, 2021

Susan Romans

Notary Public

SUSAN ROMANS
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2025

CERTIFICATION

As required by the Minnesota Public Utilities Commission's Statement of Policy on Interim Rates dated April 14, 1982, I hereby certify and affirm that the petition of Minnesota Power for approval of Proposed Interim Rates and Final Rates is in compliance with Minnesota Statutes.

Dated: November 1, 2021

Respectfully submitted,

Patrick L. Cutshall
ALLETE Vice President & Corporate Treasurer
30 West Superior Street
Duluth, MN 55802
218-355-3529

Subscribed to before me this 1st day
of November, 2021

Notary Public

SUSAN ROMANS
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2025

Akeley City Clerk
P.O. Box 67
Akeley, MN 56433

Aldrich City Clerk
P.O. Box 123
Aldrich, MN 56434

Askov City Clerk
P.O. Box 245
Askov, MN 55704

Aurora City Clerk
16 West Second Avenue N
Aurora, MN 55705

Babbitt City Clerk
71 South Drive
Babbitt, MN 55706

Backus City Clerk
P.O. Box 44
Backus, MN 56435

Barnum City Administrator
3741 Front Street
Barnum, MN 55707

Bertha City Clerk
P.O. Box 65
Bertha , MN 56437

Bigfork City Clerk
P.O. Box 196
Bigfork, MN 56628

Bovey City Clerk
P.O. Box 399
Bovey, MN 55709

Bowlus City Clerk
343 Martin Street
Bowlus, MN 56314

Brookston City Clerk
P.O. Box 304
Brookston, MN 55711

Browerville City Clerk
P.O. Box 247
Browerville, MN 56438

Bruno City Clerk
P.O. Box 66
Bruno, MN 55712

Buckman City Clerk
P.O. Box 609
Buckman, MN 56317

Burtrum City Clerk
P.O. Box 12
Upsula, MN 56384

Calumet City Clerk
P.O. Box 375
Calumet, MN 55716

Carlton City Clerk
310 Chestnut Avenue
Carlton, MN 55718

Chickamaw Beach City Clerk
6775 Indian Trail Lane
Chickamaw Beach, MN 56474

Chisolm City Administrator
316 West Lake Street
Chisolm, MN 55719

City Clerk
P.O. Box 396
Clarissa , MN 56440

Cloquet City Administrator
1307 Cloquet Avenue
Cloquet , MN 55720

Cohasset City Deputy Clerk
305 NW First Avenue
Cohasset, MN 55721

Coleraine City Clerk
P.O. Box 564
Coleraine, MN 55722

Crosby City Clerk
2 Second Street SW
Crosby, MN 56441

Cuyuna City Clerk
P.O. Box 536
Deerwood, MN 56444

Deer River City Deputy Clerk
P.O. Box 70
Deer River, MN 56636

City Clerk
P.O. Box 187
Deerwood, MN 56444

Denham City Clerk
27816 Oak Bend Way
Sturgeon Lake, MN 55783

Duluth City Clerk
330 City Hall
Duluth, MN 55802

East Gull Lake City Administrator
10790 Squaw Point Road
East Gull Lake, MN 56401

Elmdale City Clerk
8162 State Hwy 238
Bowlus, MN 56314

Eveleth City Administrator
413 Pierce Street
Eveleth, MN 55734

Flensburg City Clerk
P.O. Box 70
Flensburg, MN 56328

Floodwood City Administrator
P.O. Box 348
Floodwood, MN 55736

Fort Ripley City Clerk
P.O. Box 155
Fort Ripley, MN 56448

Genola City Clerk
13883 Highway 25
Pierz, MN 56364

Grey Eagle City Clerk
P.O. Box 116
Grey Eagle, MN 56336

Hackensack City Clerk
P.O. Box 490
Hackensack, MN 56452

Hermantown City Clerk
5105 Maple Grove Road
Hermantown, MN 55811

Hewitt City Clerk
P.O. Box 91
Hewitt , MN 56453

Hoyt Lakes City Clerk
206 Kennedy Memorial Drive
Hoyt Lakes, MN 55750

International Falls City Admin.
600 Fourth Street
International Falls, MN 56649

Iron Junction City Clerk
P.O. Box 38
Iron, MN 55751

Ironton City Clerk
P.O. Box 97
Ironton, MN 56455

Jenkins City Clerk
33861 Cottage Avenue
Jenkins, MN 56475

Kerrick City Clerk
P.O. Box 47
Kerrick, MN 55756

Kinney City Clerk
P.O. Box 321
Kinney, MN 55758

Lake Shore City Clerk
8583 Interlachen Road
Lake Shore, MN 56468

Lastrup City Clerk
P.O.Box 24
Lastrup, MN 56344

Leonidas City Clerk
132 Second Street North
Eveleth, MN 55734

Little Falls City Administrator
P.O. Box 244
Little Falls, MN 56345

Long Prairie City Clerk
615 Lake Street South
Long Prairie, MN 56347

Marble City Clerk
302 Alice Avenue
Marble, MN 55764

Meadowlands City Clerk
P.O. Box 128
Meadowlands, MN 55765

Moose Lake City Administrator
412 Fourth Street
Moose Lake, MN 55767

Menahga City Administrator
P.O. Box C
Menagha, MN 56464

Mountain Iron City Admin.
8586 Enterprise Drive South
Mountain Iron, MN 55768

Motley City Clerk
316 Highway 10 South
Motley, MN 55466

Nevis City Clerk
P.O. Box 108
Nevis, MN 56467

Nimrod City Clerk
P O Box 943
Nimrod, MN 56478

Nisswa City Clerk
P.O. Box 410
Nisswa, MN 56468

Osakis City Clerk
P.O. Box 486
Osakis, MN 56360

Park Rapids City Clerk
212 West Second Street
Park Rapids, MN 56470

Pequot Lakes City Clerk
4638 County Road 11
Pequot Lakes, MN 56472

Pillager City Administrator
306 Elm Avenue W
Pillager, MN 56473

Pine River City Clerk
P.O. Box 87
Pine River, MN 56474

Proctor City Administrator
100 Pionk Drive
Proctor, MN 55810

Ranier City Administrator
P.O. Box 186
Ranier, MN 56668

Rice City Clerk
P.O. Box 179
Rice, MN 56367

Rice Lake City Clerk
4107 West Beyer Road
Duluth, MN 55803

Rutledge City Clerk
P.O. Box 444
Willow River, MN 55795

St. Anthony City Clerk
39016 County Road 153
Albany, MN 56307

St. Rosa City Clerk
41545 County Road 167
Melrose, MN 56352

Sandstone City Administrator
P.O. Box 641
Sandstone, MN 55072

Sebeka City Clerk
213 Minnesota Avenue West
Sebeka, MN 56477

Silver Bay City Administrator
7 Davis Drive
Silver Bay, MN 55614

Sturgeon Lake City Clerk
P.O. Box 98
Sturgeon Lake, MN 55783

Swanville City Clerk
P.O. Box 296
Swanville, MN 56382

Taconite City Clerk
P.O. Box 137
Taconite, MN 55786

Tower City Clerk
P.O. Box 576
Tower, MN 55790

Trommald City Clerk
24124 Cardinal Avenue
Trommald, MN 56441

Upsala City Clerk
P.O. Box 159
Upsala, MN 56384

Verndale City Clerk
P.O. Box 156
Verndale, MN 56481

Walker City Administrator
P.O. Box 207
Walker, MN 56484

Willow River City Clerk
P.O. Box 125
Willow River, MN 55795

Winton City Clerk
P.O. Box 163
Winton, MN 55796

Wrenshall City Clerk
P.O. Box 157
Wrenshall, MN 55797

Eagle Bend City Clerk
P.O. Box 215
Eagle Bend, MN 56446

Benton County Administrator
P.O. Box 129
Foley, MN 56329

Benton County Commissioners
615 Highway 23
Foley, MN 56329

Pine County Administrator
635 Northridge Dr. NW Ste 200
Pine City, MN 55063

Pine County Commissioners
635 Northridge Drive NW
Pine City, MN 55063

Morrison County Admin Ctr
213 First Avenue SE
Little Falls, MN 56345

Morrison County Commissioners
213 SE First Avenue
Little Falls, MN 56345

St. Louis County Administrator
100 N. 5th Avenue W Room 202
Duluth , MN 55802

St. Louis County Commissioners
100 North Fifth Avenue West
Duluth, MN 55802

Otter Tail County Administrator
520 First Avenue West
Fergus Falls, MN 56537

Otter Tail County Commissioners
121 West Junius Avenue
Fergus Falls, MN 56537

Itasca County Administrator
123 NE 4th Street
Grand Rapids, MN 55744

Itasca County Commissioners
123 Fourth Street NE
Grand Rapids, MN 55744

Carlton County Coordinator
301 Walnut Avenue
Carlton, MN 55718

Carlton County Commissioners
301 Walnut Avenue
Carlton, MN 55718

Cass County Administrator
P.O. Box 3000
Walker, MN 56484

Cass County Commissioners
303 Minnesota Avenue W
Walker, MN 56484

Lake County Administrator
616 Third Avenue
Two Harbors, MN 55616

Lake County Commissioners
601 Third Avenue
Two Harbors, MN 55616

Todd County Administrator
215 First Ave S, Ste 300
Long Prairie, MN 56347

Todd County Commissioners
215 First Ave S, Ste 300
Long Prairie, MN 56437

Crow Wing County Admin.
326 Laurel Street, Suite 13
Brainerd , MN 56401

Crow Wing County Commiss.
213 Laurel Street
Brainerd, MN 56401

Stearns County Administrator
705 Courthouse Square, Rm 121
St. Cloud, MN 56303

Stearns County Commissioners
725 Courthouse Square
St. Cloud, MN 56303

Hubbard County Administrator
301 Court Avenue
Park Rapids, MN 56470

Hubbard County Commissioners
301 Court Avenue
Park Rapids, MN 56470

Wadena County Administrator
415 Jefferson Street South
Wadena, MN 56470

Wadena County Commissioners
415 Jefferson Street South
Wadena, MN 56482

Koochiching County Admin.
715 Fourth Street
International Falls, MN 56649

Koochiching County Commiss.
715 Fourth Street
International Falls, MN 56649

Biwabik City Administrator
P.O. Box 529
Biwabik, MN 55708

Buhl City Clerk
P.O. Box 704
Buhl, MN 55713

Ely City Clerk
209 E Chapman Street
Ely, MN 55731

Gilbert City Clerk
P.O. Box 548
Gilbert, MN 55741

Grand Rapids City Clerk
P.O. Box 658
Grand Rapids, MN 55741

Hibbing City Administrator
401 East 21st Street
Hibbing, MN 55746

Keewatin City Clerk
P.O. Box 86
Keewatin, MN 55753

McKinley City Clerk
P.O. Box 2088
McKinley, MN 55741

Nashwauk City Clerk
301 Central Avenue
Nashwauk, MN 55769

Pierz City Clerk
P.O. Box 367
Pierz, MN 56364

Randall City Clerk
P.O. Box 229
Randall, MN 56475

Staples City Clerk
122 Sixth Street NE Suite 1
Staples, MN 56479

Two Harbors City Administrator
522 First Avenue
Two Harbors, MN 55616

Wadena City Clerk
222 2nd Street SE P.O. Box 30
Wadena, MN 56482

Zemple City Clerk
731 Lake Street
Deer River, MN 56636

Becker County Administrator
915 Lake Avenue
Detroit Lakes, MN 56501

Becker County Commissioners
915 Lake Avenue
Detroit Lakes, MN 56502

Kanabec County Administrator
18 North Vine Street
Mora, MN 55051

Kanabec County Commissioners
18 North Vine Street
Mora, MN 55051

Mille Lacs County Administrator
635 Second Street SE
Milaca, MN 56353

Mille Lacs County Commiss.
635 Second Street SE
Milaca, MN 56353

Mille Lacs Band of Ojibwe
43408 Oodena Drive
Onamia, MN 56359

Fond Du Lac Reservation
1720 Big Lake Road
Cloquet, MN 55720

Bois Forte Tribal Government
5344 Lakeshore Drive
Nett Lake, MN 55772

Leech Lake Band of Ojibwe
190 Sailstar Drive NW
Cass Lake, MN 56633

Agram Township Clerk
23647 118th Street
Pierz, MN 56364

Akeley Township Clerk
15 Broadway St. W.
Akeley, MN 56433

Alborn Township Clerk
6388 Swan Lake Road
Alborn , MN 55702

Arbo Township Clerk
28915 Bello Circle
Grand Rapids, MN 55744

Atkinson Township Clerk
505 Mason Drive
Wrenshall, MN 55797

Balkan Township
P.O. Box 66
Chisholm, MN 55719

Bay Lake Township
13861 County Road 10
Deerwood , MN 56444

Belle Prairie Township Clerk
16515 203rd Street
Little Falls, MN 56345

Bellevue Township Clerk
9753 Iris Road
Royalton, MN 56373

Blackhoof Township Clerk
2391 County Road 105
Barnum, MN 55707

Bruce Township Hall
26234 285th Avenue
Long Prairie, MN 56347

Bruno Township Clerk
55974 Sand Creek Road
Bruno, MN 55712

Buckman Township Clerk
5120 260th Avenue
Royalton, MN 56373

Cherry Township Clerk
4036 Hartman Road
Iron, MN 55751

Clinton Township Clerk
P.O. Box 147
Iron, MN 55751

Duluth Township Clerk
6092 Homestead Road
Duluth, MN 55804

Fall Lake Township Clerk
13550 Thirteen Corners
Ely, MN 55731

Finlayson Township Clerk
24193 Wooder Circle
Finlayson, MN 55735

Fredenberg Township Clerk
5104 Fish Lake Rd
Duluth, MN 55803

Gnesen Township
4011 W Pioneer Rd
Duluth, MN 55803

Grand Lake Township Clerk
P.O. Box 1023
Twig, MN 55791

Great Scott Township Clerk
P.O. Box 277
Kinney, MN 55758

Green Prairie Township Clerk
14513 190th Street
Little Falls, MN 56345

Greenway Township Clerk
550 5th Avenue
Calumet, MN 55716

Grey Eagle Township Clerk
P.O. Box 202
Grey Eagle, MN 56336

Henrietta Township Clerk
P.O. Box 81
Park Rapids, MN 56470

Hubbard Township Clerk
11757 County 106
Park Rapids, MN 56470

Ideal Township
35458 Butternut Point Road
Pequot Lakes, MN 56472

Iron Range Township Clerk
P.O. Box 96
Taconite, MN 55786

Irondale Township Clerk
19121 County Road 12
Ironton, MN 56455

Township Clerk
P.O. Box 71
Pequot Lakes, MN 56472

Lavell Township Clerk
1832 Danahy Road
Hibbing, MN 55746

Little Falls Township Clerk
20313 Highway 27
Little Falls, MN 56345

Little Sauk Township Clerk
18557 County 11
Long Prairie, MN 56347

Lone Pine Township Clerk
31469 E. Shore Drive
Pengilly, MN 55775

Long Prairie Township Clerk
23607 271st Avenue
Long Prairie, MN 56347

Mahtowa Township Clerk
3041 County Road 4
Carlton, MN 55718

Moose Lake Township Clerk
P.O. Box 193
Moose Lake, MN 55767

Partridge Township Clerk
67947 Sunrise Road
Bruno, MN 55712

Perch Lake Township Clerk
720 Salmi Road
Cloquet, MN 55720

Pike Creek Township Clerk
12202 130th Street
Little Falls, MN 56345

Powers Township Clerk
3416 Ox Yoke Road NW
Hackensack, MN 56452

Round Prairie Township Clerk
25442 204th Street
Long Prairie, MN 56347

Township Clerk
P.O. Box 34
Walker, MN 56484

Solway Township Clerk
4029 Munger Shaw Road
Cloquet, MN 55720

Sturgeon Lake Township
86917 Spring Creed Rd
Willow River, MN 55795

Thomson Township Clerk
P.O. Box 92
Esko , MN 55733

Breitung Township Clerk
P.O. Box 564
Soudan, MN 55782

Brevator Township Clerk
P.O. Box 623
Cloquet, MN 55720

Canosia Township Clerk
4896 Midway Road
Duluth, MN 55811

Fayal Town Clerk
4375 Shady Lane
Eveleth, MN 55791

Industrial Township Clerk
7578 Albert Road
Saginaw, MN 55779

Lakewood Township Clerk
3110 Strand Road
Duluth, MN 55803

Midway Township Clerk
3302 Midway Road
Duluth, MN 55810

Normanna Township Clerk
6083 Lakewood Road
Duluth, MN 55804

Town of White Clerk
P.O. Box 146
Aurora, MN 55705

Ward Township Clerk
26997 County 18
Browerville, MN 56438

Windemere Township Clerk
90117 Shoreside Land
Sturgeon Lake, MN 55783

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota
Docket No. E015/GR-21-335
Completeness Checklist

Source	Information Required	Location
	Minnesota Statutes and Rules	
7825.3200	**Notice of Change in Rates**	
	A utility filing for a change in rates shall serve notice to the commission at least 90 days prior to the proposed effective date of the modified rates. Such notice shall include the items prescribed below for:	Volume 1, Notice of Change in Rates
(A)	A. general rate changes: (1) proposal for change in rates as prescribed in part 7825.3500; (2) modified rates as prescribed in part 7825.3600; (3) expert opinions and supporting exhibits as prescribed in part 7825.3700; (4) informational requirements as prescribed in parts 7825.3800 to 7825.4400; and (5) statement indicating the method of insuring the payment of refunds as prescribed in part 7825.3300;	Volume 1, and see below for reference to parts 7825.3600, 7825.3700, 7825.3800-4400, and 7825.3300
7825.3300	**Methods and Procedures for Refunding**	
	An unqualified agreement, signed by an authorized official of the utility, to refund to the customers or credit to customers' accounts within 90 days from the effective date of the commission order any portion of the increase in rates determined to be unreasonable together with interest at the average prime interest rate computed from the effective date of the proposed rates through the date of refund or credit.	Volume 1, Agreement and Undertaking
7825.3500	**Proposal for Change in Rates**	
	The Utility's proposal for a change in rates shall summarize the notice of change in rates and shall include the following information:	Volume 1, Notice of Change in Rates
(A)	name, address, and telephone number of the utility without abbreviation and the name and address and telephone number of the attorney for the utility, if there be one;	Volume 1, Notice of Change in Rates, Section B.1 and B.2
(B)	date of filing and date modified rates are effective;	Volume 1, Notice of Change in Rates, Section B.3
(C)	description and purpose of the change in rates requested;	Volume 1, Notice of Change in Rates, Section B.4
(D)	effect of the change in rates expressed in gross revenue dollars and as a percentage of test year gross revenue; and	Volume 1, Notice of Change in Rates, Section B.5
(E)	signature and title of utility officer authorizing the proposal.	Volume 1, Notice of Change in Rates, Section B.6

Source	Information Required	Location
7825.3600	**Modified Rates**	
	Revised or new pages to the rate book previously filed with the commission and by identifying those pages which were not changed. In addition, each revised page shall contain the revision number and the page number of the revised page.	Volume 1, Interim Tariff Sheets – Redlined, Interim Tariff Sheets – Clean Volume 3, Direct Schedules J-1- Summary of Tariff Sheets Not Changed, J-2- Clean General Tariff Sheets, J-3-Redlined General Tariff Sheets
7825.3700	**Expert Opinions and Supporting Exhibits**	
	Expert opinions and supporting exhibits shall include written statements, in question and answer format, together with supporting exhibits of utility personnel and other expert witnesses as deemed appropriate by the utility in support of the proposal.	Volume 2, Direct Testimony and Schedules of: Jennifer J. Cady, Frank L. Frederickson, Patrick L. Cutshall, Ann E. Bulkley, Julie I. Pierce, Benjamin S. Levine, Joshua G. Rostollan, Todd Z. Simmons, Daniel W. Gunderson, Laura E. Krollman, John D. Armbruster, Amanda L. Turner, Stewart J. Shimmin, and Leah N. Peterson.
7825.3900	**Jurisdictional Financial Summary Schedule**	
	A jurisdictional financial summary schedule as required by part 7825.3800 shall be filed showing:	
(A)	the proposed rate base, operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the test year;	Volume 1, Direct Schedule A-2 (IR) Volume 3, Direct Schedule A-1
(B)	the actual unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year; and	Volume 1, Direct Schedule D-5 (IR) Volume 3, Direct Schedule A-1
(C)	the projected unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income under present rates, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.	Volume 3, Direct Schedule A-1

Source	Information Required	Location
7825.4000	**Rate Base Schedules**	
	The following rate base schedules as required by part 7825.3800 shall be filed:	
(A)	A rate base summary schedule by major rate base component (e.g. plant in service, construction work in progress, and plant held for future use) showing the proposed rate base, the unadjusted average rate base for the most recent fiscal year and unadjusted average rate base for the projected fiscal year. The totals for this schedule shall agree with the rate base amounts included in the financial summary.	Volume 1, Direct Schedule A-3 (IR) and Direct Schedule D-1 (IR) Volume 3, Direct Schedule B-1 and Direct Schedule B-2 (Total Company)
(B)	A comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component showing:	
(1)	total utility and the proposed jurisdictional rate base amounts for the test year including the adjustments, if any, used in determining the proposed rate base;	Volume 1, Direct Schedule B-1 (IR) Volume 3, Direct Schedule B-3
(2)	the unadjusted average total utility and jurisdictional rate base amounts for the most recent fiscal year and the projected fiscal year.	Volume 3, Direct Schedule B-4
(C)	Adjustment schedules, if any, showing the title, purpose, and description and the summary calculations of each adjustment used in determining the proposed jurisdictional rate base.	Volume 1, Direct Schedules B-2 (IR) and B-3 (IR) Volume 3, Direct Schedules B-5 and B-6 Volume 2, Turner Direct at Section V.A Volume 4, Workpapers ADJ-RB 1 through ADJ-RB 15
(D)	A summary by rate base component of the assumptions made and the approaches used in determining average unadjusted rate base for the projected fiscal year. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.	Volume 1, Direct Schedule B-2 (IR) Volume 3, Direct Schedules B-7 through B-15 Volume 4, Workpapers RB-1 through RB-14
(E)	For multijurisdictional utilities only, a summary by rate base component of the jurisdictional allocation factors used in allocating the total utility rate base amounts to the Minnesota jurisdiction. This summary shall be supported by a schedule showing for each allocation factor the total utility and jurisdictional statistics used in determining the proposed rate base and the Minnesota jurisdictional rate base for the most recent fiscal year and the projected fiscal year.	Volume 3, Direct Schedule B-16 through B-19 Volume 2, Shimmin Direct at Schedule 1 and Schedule 2

Source	Information Required	Location
7825.4100	**Operating Income Schedules**	
	The following operating income schedules as required by part 7825.3800 shall be filed:	
(A)	A summary schedule of jurisdictional operating income statements which reflect proposed test year operating income, and unadjusted jurisdictional operating income for the most recent fiscal year and the projected fiscal year calculated using present rates.	Volume 1, Direct Schedule A-4 (IR) and Direct Schedule D-3 (IR) Volume 3, Direct Schedules C-1 and C-2
(B)	For multijurisdictional utilities only, a schedule showing the comparison of total utility and unadjusted jurisdictional operating income statement for the test year, for the most recent fiscal year and the projected fiscal year. In addition, the schedule shall provide the proposed adjustments, if any, to jurisdictional operating income for the test year together with the proposed operating income statement.	Volume 1, Direct Schedule B-5 (IR) Volume 3, Direct Schedules C-3 and C-4
(C)	For investor-owned utilities only, a summary schedule showing the computation of total utility and allocated Minnesota jurisdictional federal and state income tax expense and deferred income taxes for the test year, the most recent fiscal year, and the project fiscal year. This summary schedule shall be supported by a detailed schedule, showing the development of the combined federal and state income tax rates.	Volume 3, Direct Schedules C-5 through C-8
(D)	A summary schedule of adjustments, if any, to jurisdictional test year operating income and detailed schedules for each adjustment providing an adjustment title, purpose and description of the adjustment, and summary calculations.	Volume 1, Direct Schedules B-6 (IR) and B-7 (IR) Volume 3, Direct Schedules C-9 through C-11 Volume 2, Turner Direct at Section V.B Volume 4, Workpapers, ADJ-IS-1 through ADJ-IS-31
(E)	A schedule summarizing the assumptions made and the approaches used in projecting each major element of operating income. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.	Volume 1, Direct Schedule B-6 (IR) Volume 3, Direct Schedule C-12 Volume 4, Workpapers, IS-1 through IS-12

Source	Information Required	Location
(F)	For multijurisdictional utilities only, a schedule providing, by operating income element, the factor or factors used in allocating total utility operating income to Minnesota jurisdiction. This schedule shall be supported by a schedule which sets forth the statistics used in determining each jurisdictional allocation factor for the test year, the most recent fiscal year, and the projected fiscal year.	Volume 3, Direct Schedules C-13 through C-16 Volume 4, Workpapers, AF-1 through AF-6
7825.4200	**Rate of Return Cost of Capital Schedules**	
	The following rate of return cost of capital schedules as required by part 7825.3800 shall be filed:	
(A)	a rate of return cost of capital summary schedule showing the calculation of the weighted cost of capital using the proposed capital structure and the average capital structures for the most recent fiscal year and the projected fiscal year. This information shall be provided for the unconsolidated parent and subsidiary corporations, or for the consolidated parent corporation.	Volume 1, Direct Schedule D-6 (IR) Volume 3, Direct Schedule D-1 Volume 4, Workpapers, COC-1
(B)	supporting schedules showing the calculation of the embedded cost of long-term debt, if any, and the embedded cost of preferred stock, if any, at the end of the most recent fiscal year and the projected fiscal year.	Volume 3, Direct Schedule D-2
(C)	schedule showing average short-term securities for the proposed test year, most recent fiscal year, and the projected fiscal year.	Volume 2, Cutshall Direct at Section I Volume 3, Direct Schedule D-3
7825.4300	**Rate Structure and Design Information**	
	The following rate structure and design information as required by part 7825.3800 shall be filed:	
(A)	A summary comparison of test year operating revenue under present and proposed rates by customer class of service showing the difference in revenue and the percentage change.	Volume 3, Direct Schedule E-1 Volume 4, Workpapers IR-1
(B)	A detailed comparison of test year operating revenue under present and proposed rates by type of charge including minimum, demand, energy by block, gross receipts, automatic adjustments, and other charge categories within each rate schedule and within each customer class of service.	Volume 3, Direct Schedule E-1 and Direct Schedule E-2 Volume 4, Workpapers, IR-2

Source	Information Required	Location
(C)	A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations. Such study is appropriate whenever the utility proposed a change in rates which results in a material change in its rate structure.	Volume 3, Direct Schedule E-3 Volume 4, Workpapers, COS 1 through COS-4
7825.4400	**Other Supplemental Information**	
	The following supplemental information as required by part 7825.3800 shall be filed:	
(A)	Annual report to stockholders or members including financial statement and statistical supplements for the most recent fiscal year. If a utility is not audited by an independent public accountant, unaudited financial statements will satisfy this filing requirement.	Volume 3, Direct Schedule F-1
(B)	For investor-owned utilities only, a schedule showing the development of the gross revenue conversion factor.	Volume 3, Direct Schedule F-2
(C)	For cooperatives only, REA Form 7, Financial and Statistical Report for the last month of the most recent fiscal year.	N/A
(D)	For cooperatives only, REA Form 7A, Annual Supplement to Financial and Statistical Report.	N/A
(E)	For REA cooperatives only, REA Form 325, Financial Forecast.	N/A
7829.2400	**Filing requiring determination of gross revenue.**	
Subpart 1	Summary. A utility filing a general rate case or other filing that requires determination of its gross revenue requirement shall include, on a separate page, a brief summary of the filing, sufficient to apprise potentially interested parties of its nature and general content.	Volume 1, Summary of Filing
Subpart 2	Service. A utility filing a general rate change request shall serve copies of the filing on the department and the Office of the Attorney General. The utility shall serve the filing or the summary described in Subpart 1 on the persons on the applicable general service list and persons who were parties to its last general rate case or incentive plan proceeding.	Volume 1, Notice of Change in Rates and Service List

Source	Information Required	Location
Subpart 3	Notice to public and governing bodies. A utility seeking a general rate change shall give notice of the proposed change to the governing body of each municipality and county in its service area and to its ratepayers. The utility shall also public notice of the proposed change in newspapers of general circulation in all county seats in its service area.	Volume 1, Proposed Notice to Counties and Municipalities
Minn. Stat. § 216B.16		
Subd. 1	Unless the commission otherwise orders, no public utility shall change a rate which has been duly established under this chapter, except upon 60 days' notice to the commission. The notice shall include statements of facts, expert opinions, substantiating documents, and exhibits, supporting the change requested, and state the change proposed to be made in the rates then in force and the time when the modified rates will go into effect.	Volume 1, Notice of Change in Rates
	If the filing utility does not have an approved energy conservation improvement plan on file with the department, it shall also include in its notice an energy conservation plan pursuant to section 216B.241. A filing utility subject to rate regulation under section 216B.026 shall reference in its notice the energy conservation improvement plans of the generation and transmission cooperative providing energy conservation improvement programs to members of the filing utility pursuant to section 216B.241.	See *In the Matter of Minnesota Power's 2021-2023 Electric Conservation Improvement Program Triennial Plan*, Docket No. E015/CIP-20-476, DECISION (Nov. 24, 2020). *In the Matter of Minnesota Power's CIP Modification Request Filed December 14, 2020*, Docket No. E015/CIP-20-476, DECISION (Feb. 12, 2021).
	The filing utility shall give written notice, as approved by the commission, of the proposed change to the governing body of each municipality and county in the area affected.	Volume 1, Proposed Notice to Counties and Municipalities
	All proposed changes shall be shown by filing new schedules or shall be plainly indicated upon schedules on file and in force at the time.	Volume 1, Interim Tariff Sheets – Redlined, Interim Tariff Sheets – Clean Volume 3, Direct Schedules J-1- Summary of Tariff Sheets Not Changed, J-2- Clean General Tariff Sheets, J-3-Redlined General Tariff Sheets

Source	Information Required	Location
Subd 3(b)	Interim rate. (b) Unless the commission finds that exigent circumstances exist, the interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include: (1) a rate of return on common equity for the utility equal to that authorized by the commission in the utility's most recent rate proceeding; (2) rate base or expense items the same in nature and kind as those allowed by a currently effective order of the commission in the utility's most recent rate proceeding; and (3) no change in the existing rate design. In the case of a utility which has not been subject to a prior commission determination, the commission shall base the interim rate schedule on its most recent determination concerning a similar utility.	Volume 1, Notice and Petition for Interim Rates
Subd. 8	Advertising expense. (a) The commission shall disapprove the portion of any rate which makes an allowance directly or indirectly for expenses incurred by a public utility to provide a public advertisement which: (1) is designed to influence or has the effect of influencing public attitudes toward legislation or proposed legislation, or toward a rule, proposed rule, authorization or proposed authorization of the Public Utilities Commission or other agency of government responsible for regulating a public utility; (2) is designed to justify or otherwise support or defend a rate, proposed rate, practice or proposed practice of a public utility; (3) is designed primarily to promote consumption of the services of the utility; (4) is designed primarily to promote good will for the public utility or improve the utility's public image; or (5) is designed to promote the use of nuclear power or to promote a nuclear waste storage facility. (b) The commission may approve a rate which makes an allowance for expenses incurred by a public utility to disseminate information which: (1) is designed to encourage conservation of energy supplies; (2) is designed to promote safety; or (3) is designed to inform and educate customers as to financial services made available to them by the public utility. (c) The commission shall not withhold approval of a rate because it makes an allowance for expenses incurred by the utility to disseminate information about corporate affairs to its owners.	Volume 2, Turner Direct at Section V.B.1 Volume 3, Direct Schedule G-1, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-1

Source	Information Required	Location
Subd. 9	Charitable contribution. The commission shall allow as operating expenses only those charitable contributions that the commission deems prudent and that qualify under section 300.66, subdivision 3. Only 50 percent of the qualified contributions are allowed as operating expenses.	Volume 2, Turner Direct at Section V.B.2 Volume 3, Direct Schedule G-2, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-2
Subd. 13	Economic and community development. The commission may allow a public utility to recover from ratepayers the expenses incurred for economic and community development.	Volume 2, Rostollan Direct at Section IV.B; Turner Direct at Section V.B.3. Volume 3, Direct Schedule G-5 Volume 4, Workpapers, ADJ-IS-3
Subd. 17	(a) The commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service. In order to assist the commission in evaluating the travel, entertainment, and related employee expenses that may be allowed for ratemaking purposes, a public utility filing a general rate case petition shall include a schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories: (1) travel and lodging expenses; (2) food and beverage expenses; (3) recreational and entertainment expenses; (4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements; (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements; (6) dues and expenses for memberships in organizations or clubs; (7) gift expenses; (8) expenses related to owned, leased, or chartered aircraft; and (9) lobbying expenses.	Volume 2, Turner Direct at Sections V.B.4 to V.B.7 Volume 2, Rostollan Direct at Section IV.B, Section IV.C, and Direct Schedules 10 and 11 Volume 3, Direct Schedules H-1 to H-12

Source	Information Required	Location
	(b) To comply with the requirements of paragraph (a), each applicable expense incurred in the most recently completed fiscal year must be itemized, separately, and each itemization must include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization required by this paragraph may be provided using standard accounting reports already utilized by the utility involved in the rate case, in a written format or an electronic format that is acceptable to the commission. For expenses identified in response to paragraph (a), clauses (1) and (2), the utility shall disclose the total amounts for each expense category and provide separate itemization for those expenses incurred by or on behalf of any employee at the level of vice president or higher and for board members. The petitioning utility shall also provide a one-page summary of the total amounts for each expense category included in the petitioning utility's proposed test year.	Volume 2, Rostollan Direct at Section IV.B, Section IV.C, and Direct Schedules 10 and 11 Volume 3, Direct Schedules H-1 to H-12
	(c) Except as otherwise provided in this paragraph, data submitted to the commission under paragraph (a) are public data. The commission or an administrative law judge assigned to the case may treat the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, as private data on individuals as defined in section 13.02, subdivision 12, or issue a protective order governing release of the salary, if the utility establishes that the competitive disadvantage to the utility that would result from release of the salary outweighs the public interest in access to the data. Access to the data by a government entity that is a party to the rate case must not be restricted.	Volume 3, Direct Schedule H-5A.
Commission Policy Statements		
Policy Statement		
Advertising	Statement that recovery is requested only for permitted advertisements.	Volume 2, Turner Direct at Section V.B.1
	Description of advertisements for which recovery is requested.	Volume 2, Turner Direct at Section V.B.1 Volume 3, Direct Schedule G-1, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-1

Source	Information Required	Location
	Sample advertisements for which recovery is requested, including a schedule that: 1. Identifies the sample ad. 2. Categorizes the advertisements by allowable and disallowable type. 3. Defines the percentage by which the content fits into the allowable and disallowable statutory categories. 4. Provides the corresponding test year dollar amount for each ad. 5. Describes the period of time during which each ad will be used, the service area in which it will appear, and the media employed.	Volume 3, Direct Schedule G-1 Volume 4, Workpapers, ADJ-IS-1
Charitable Contributions	Evidence as to whether the recipients of the contributions: serve the utility's Minnesota service area; are nondiscriminatory in selecting recipients; and do not promote political or special interest groups.	Volume 2, Turner Direct at Section V.B.2 Volume 3, Direct Schedule G-2, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-2
	Evidence as to what organizations are gifted, their activities, and that no part of the contribution goes to benefit any private stockholder or individual.	Volume 3, Direct Schedule G-2, Direct Schedule C-9, and Direct Schedule C-10 Volume 4, Workpapers, ADJ-IS-2
	Itemized schedule showing amount, recipient and time of donations.	Volume 3, Direct Schedule G-2 Volume 4, Workpapers, ADJ-IS-2
Organizational Dues	Schedule showing each organization being paid, the number of employees belonging to each organization and the dollar amount of dues being paid to each organization.	Volume 2, Turner Direct at Section V.B.4 Volume 2, Rostollan Direct at Section IV.C Volume 3, Direct Schedule G-3 and Direct Schedule H-6 Volume 4, Workpapers, ADJ-IS-4

Source	Information Required	Location
	Testimony explaining whether the primary purpose of each organization is educating utility employees about providing improved utility service, training employees to become better qualified to provide improved utility service, or membership is a necessary qualification for employees to carry on their responsibilities or provides essential information to the utility.	Volume 2, Turner Direct at Section V.B.4 Volume 2, Rostollan Direct at Section IV.C Volume 3, Direct Schedule G-3 and Direct Schedule H-6 Volume 4, Workpapers, ADJ-IS-4
Research Expenses	A schedule which describes each research activity for which an expense is claimed and itemizes and supports all expense for each activity.	Volume 2, Rostollan Direct at Section IV.D Volume 3, Direct Schedule G-4
	Testimony that explains the nature of control of the research, identifies who will conduct the research, describes who will benefit from the research and the time needed for those benefits to accrue, and who will acquire property rights to the products that result from the research.	Volume 2, Rostollan Direct at Section IV.D Volume 3, Direct Schedule G-4
Cash Working Capital	Lead/lag study with: 1) lead time divided into service to meter reading; meter reading to billing; and billing to collection; and 2) lag expenses divided into categories such as fuel, purchased power, labor, etc.	Volume 2, Turner Direct at Section III.B Volume 4, Workpapers, OS-2
	Other issues may include average minimum cash balances required, depreciation, dividends and interest on debt.	Volume 2, Turner Direct at Section III.B Volume 3, Direct Schedule B-15 Volume 4, Workpapers OS-2, ADJ-RB-3, ADJ-RB-14
Commission's Statement of Policy on Interim Rates Adopted April 14, 1982	http://mn.gov/puc-stat/documents//pdf_files/012031.pdf	
Page 2(1)	Name, address, and telephone number of utility without abbreviation and the name, address, and telephone number of the attorney for the utility, or other representative upon whom official service may be made.	Volume 1, Notice and Petition for Interim Rates, Section B.1
Page 2(2)	Date of filing and date proposed interim rates are requested to become effective.	Volume 1, Notice and Petition for Interim Rates, Section B.2
Page 2(3)	Description and need for interim rates.	Volume 1, Notice and Petition for Interim Rates, Section B.3

Source	Information Required	Location
Page 2(4)	Description and corresponding dollar amount changes included in interim rates as compared with most current approved general rate case and with the most recent actual year for which audited data is available. The data for the most recent actual year should be for the same time period in months as the test year, if the test year is a projected test year.	Volume 1, Notice and Petition for Interim Rates, Section B.4 and Direct Schedules C-1 (IR) to C-8 (IR) and D-1 (IR) to D-7
Page 2(5)	Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues.	Volume 1, Notice and Petition for Interim Rates, Section B.5 and Direct Schedule C-5 (IR)
Page 2(6)	Certification by officer of the utility that affirms the proposed interim rate petition is in compliance with Minnesota Statutes.	Volume 1, Notice and Petition for Interim Rates, Section B.6 Volume 1, Certification
Page 2(7)[1]	Signature and title of the utility officer authorizing the proposed interim rates.	Volume 1, Notice and Petition for Interim Rates, Section B.8
Page 3(1)	A schedule showing the interim rate of return calculation. This schedule should show the capital structure and rate of return calculation approved by the Commission in the most recent general rate case; the capital structure and rate of return calculation proposed for interim rates; and a description and corresponding dollar amount of any changes between the two capital structures.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules
Page 3(2)	A schedule showing the interim operating income statement. This schedule should show the same operating income statement accounts as filed in the general rate case. Also, the schedule should include the operating income statement approved by the Commission in the most recent general rate case; the equivalent operating income statement corresponding with the most recent actual year for which audited data is available and corresponding with the same period in months as the test year, if the test year is a projected test year; and the operating income statement proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the operating income statements should be provided. Work papers should be provided which show how revenues, AFUDC, taxes, expenses, and other income statement components have been determined.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules Volume 4, Workpapers, RB-1 through RB-14, IS-1 through IS-12

[1] Item 7 actually appears on Page 3 of the Statement of Policy.

Source	Information Required	Location
Page 3(3)	A schedule showing the interim proposed rate base. This schedule should include the average rate base approved by the Commission in the most recent general rate case; the equivalent average rate base corresponding with the most recent actual year for which audited data is available and corresponding with the same period in months as the test year, if the test year is a projected test year; and the average rate base proposed for interim rates. A description of all changes and corresponding dollar amounts between each of the rate bases should be provided. Workpapers should be provided which show how the rate base components have been determined.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules Volume 4, Workpapers, IR-1 and IR-2
Page 3(4)[2]	A schedule showing revenue deficiency calculations for each of the operating income statements and rate bases requested in (2) and (3) above. The revenue deficiency should be calculated for the actual data and the interim data using the rate of return calculated in (1) above.	Volume 1, Notice and Petition for Interim Rates, Section B.9 and Schedules
	Modified Tariffs	Volume 1, Notice and Petition for Interim Rates, Section B.10 Volume 1, Interim Tariff Sheets – Redlined; Interim Tariff Sheets – Clean
	Notices	Volume 1, Notice and Petition for Interim Rates Section B.11 Volume 1, Proposed Notice to Counties and Municipalities; Proposed Notice to Customers; Proposed Newspaper Publication
	All Utility Dockets	
E999/CI-03-869 **E999/CI-04-1616**	**In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. § 216B.1691** **In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits**	
ORDER ESTABLISHING INITIAL PROTOCOLS FOR TRADING RENEWABLE ENERGY CREDITS (DEC. 18, 2007)	9. Utilities seeking recovery of prudent costs related to registration, annual fees and transaction costs related to renewable energy credit purchases shall file specific proposals for cost recovery, to be reviewed by the Department and other parties.	Volume 2, Turner Direct at Section VII.A

[2] Item 4 actually appears on Page 4 of the Statement of Policy.

Source	Information Required	Location
E,G999/CI-08-132	**In the Matter of a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues**	
ORDER ESTABLISHING CRITERIA AND STANDARDS TO BE UTILIZED IN PILOT PROPOSALS FOR REVENUE DECOUPLING (JUNE 19, 2009)	[If a utility seeks Commission approval for a pilot decoupling proposal,] decoupling pilot proposals should be filed and implemented within a rate case.	Minnesota Power has not included any proposal for decoupling in this rate case.
E999-AA-09-961 **E999/AA-10-884**	**In the Matter of the Review of the 2008-2009 Annual Automatic Adjustment Reports for All Electric Utilities** **In the Matter of the Review of the 2009-2010 Annual Automatic Adjustment Reports for All Electric Utilities**	
ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS (APR. 6, 2012)	11. The Commission will require the utilities to continue to show benefits of the MISO Day 1 in their rate cases before receiving cost recovery of MISO Schedule 10 costs.	Volume 2, Pierce Direct at Section II
	Minnesota Power Dockets	
E015/AI-08-339 **E015/AI-08-340** **E015/AI-08-341**	**In the Matter of Minnesota Power's Petition for Approval of an Administrative Services Agreement between ALLETE, Inc. and its Subsidiary, ALLETE Properties, LLC (f/k/a MP Real Estate Holdings, Inc.)** **In the Matter of Minnesota Power's Petition for Approval of an Administrative Services Agreement Between ALLETE, Inc. and its Subsidiary, Superior Water, Light and Power (SWL&P)** **In the Matter of Minnesota Power's Petition for Approval of an Administrative Services Agreement Between ALLETE, Inc. and its Subsidiary, Minnesota Power Enterprises, Inc. (MP Enterprises)**	
ORDER (JAN. 13, 2009)	The Company must demonstrate in future rate cases that the First Amendment to the Services Agreement has not resulted in cross-subsidization by Minnesota Power's ratepayers of the activities of its affiliated companies.	Volume 2, Rostollan Direct at Section III.B and Section III.D

Source	Information Required	Location
E015/PA-08-928	**In the Matter of a Petition for Approval of a Redevelopment Agreement for the M.L. Hibbard Units 3 & 4 Boilers and Related Facilities from the City of Duluth and for Approval of Investments and Expenditures at the M.L. Hibbard Energy Center Through Minnesota Power's Renewable Energy Rider under Minn. Stat. § 216B.1645**	
ORDER APPROVING PURCHASE AND MAKING FINDINGS RELEVANT TO RECOVERY OF UPGRADE EXPENDITURES THROUGH THE RENEWABLE ENERGY RIDER (SEPT. 22, 2009)	4.a. MP shall address, in the first rate case after Hibbard goes into service and in all subsequent rate cases until the Commission orders otherwise, whether the Hibbard facility is used and useful in providing retail utility service and whether the investments and related expenses and revenues are reasonable and prudently incurred.	Volume 2, Simmons Direct at Section IV.D
E015/GR-09-1151	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
FINDINGS OF FACT, CONCLUSIONS, AND ORDER (NOV. 2, 2010)	17. The Company shall account for future lobbying expenses by assigning both employee and contract lobbying expenses to FERC Account 426.4 and excluding this category from operating and maintenance expenses recovered from ratepayers.	Volume 2, Rostollan Direct at Section IV.G Volume 2, Turner Direct at Sections V.B.4 to V.B.5 Volume 3, Direct Schedules H-1, H-8, and H-11
	18. The Company shall continue working with the [Division of Energy Resources] on improving the electronic linkage between its Class Cost of Service Study, its forecasting processes, and its revenue models.	Volume 2, Shimmin Direct at Section II
	19. In future rate case filings, the Company shall provide all data used in its test year sales forecasts at least 30 days before filing the rate case.	September 29, 2021 filing in Docket No. E015/GR-21-335 eDocket Document ID 20219-178331-01 (TS) 20219-178331-02
	20. In future rate case filings, the Company shall conduct any Class Cost of Service Study (CCOSS) by calculating and assigning income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS.	Volume 2, Shimmin Direct at Section II and Direct Schedule 1
E015/GR-16-664	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
FINDINGS OF FACT, CONCLUSIONS, AND	13. Recovery of the Taconite Harbor two restart costs will end after the total estimated costs of $2.5 million for two restart events is recovered.	Volume 2, Simmons Direct at Section IV.C

Source	Information Required	Location
ORDER (MAR. 12, 2018)	19. Minnesota Power may include $350,000 in O&M expense in the test year for credit-card-processing fees. The Company shall track over/under-collections for true-up in a future rate case.	Volume 2, Turner Direct at Section V.B.8 Volume 4, Workpaper ADJ-IS-8
	36. Minnesota Power shall reduce its revenue requirement to remove proration of accumulated deferred income taxes (ADIT). Proration of ADIT is required for interim rates.	Volume 2, Armbruster Direct at Section II.C Volume 4, Workpaper ADJ-RB-8
	47. In future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate case at the end of the rate case if Minnesota Power wants to continue rider recovery.	Volume 2, Simmons Direct at Section IV.G Volume 2, Turner Direct at Section II Volume 2, Shimmin Direct at Section VI Volume 2, Simmons Direct at Section IV.G Volume 2, Gunderson Direct at Section III.D
E015/M-16-776	**In the Matter of Minnesota Power's Renewable Resources Rider and 2017 Renewable Factor**	
NOVEMBER 8, 2017 ORDER	3. Minnesota Power must return any amortized federal investment tax credits associated with Thomson Hydro to ratepayers through future RRR filings until they can be included in base rates in a subsequent rate case	Volume 2, Turner Direct at Section VII.B
E015-PA-17-457 **E015-PA-17-459** **E015-PA-17-460** **E015-PA-17-461**	**In the Matter of the Petition of Minnesota Power for Approval of a Purchase Agreement for the Sale of the Aurora Service Center to Lakehead Constructors, Inc.** **In the Matter of the Petition of Minnesota Power for Approval of a Purchase Agreement for the Sale of the Chisolm Service Center to United Way of Northeastern Minnesota, Inc.** **In the Matter of the Petition of Minnesota Power for Approval of a Purchase Agreement for the Sale of Land and Buildings near the Boswell Energy Center to Airmark, Inc. d/b/a Nelson Wood Shims** **In the Matter of the Petition of Minnesota Power for Approval of a Purchase Agreement for the Purchase of the Long Prairie Service Center from the State of Minnesota Department of Military Affairs**	
ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018)	2. A. Minnesota Power shall do the following: Use deferred accounting to create a regulatory liability for these transactions as recommended by the Minnesota Department of Commerce	Volume 2, Turner Direction at Section V.B.14

Source	Information Required	Location
E015-AI-17-568	**In the Matter of Minnesota Power's Petition for Approval of Energy*Forward* Resource Package**	
ORDER APPROVING AFFILIATED-INTEREST AGREEMENTS WITH CONDITIONS (JAN. 24, 2019)	4. In any future rate case in which Minnesota Power seeks to recover costs associated with the NTEC purchase, the Company will be required to prove the propriety of the costs associated with this deal structure in contrast to other cost structures that the Company chose not to use, which would include a PPA-like levelized payment structure.	Not applicable; Minnesota Power is not seeking recovery of costs associated with the NTEC purchase in this rate case filing.
E999/M-17-377	**In the Matter of the 2017 Biennial Transmission Projects Report**	
JUNE 12, 2018 ORDER	The Department requested a summary of all mitigation measures added at any step in the permitting process for new energy facilities, the reason for the mitigation measure, the entity requesting mitigation, and the cost of the measure. Minnesota Power provided a statement of no objection to providing information on the cost of mitigation measures in future rate recovery requests for new energy facilities.	N/A
E999/CI-03-802	**In the Matter of an Investigation into the Appropriateness of Electric Energy Cost Adjustments**	
ORDER APPROVING COMPLIANCE FILINGS (NOV. 5, 2019)	2. In Minnesota Power's initial filing for its next rate case, the Company "shall demonstrate that its proposed base rates exclude Fuel Clause Adjustment-related costs."	Volume 2, Peterson Direct at Section III.J
E015/M-16-664	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
TESTIMONY COMMITMENTS TO THE DEPARTMENT OF COMMERCE	MP to confirm that $94,931,550 is the estimated revenues for base rider cash included in the rate case.	Volume 2, Turner Direct at Section X.C
	All MP financial witnesses will need to tie out their numbers to the overall revenue witness. MP may use their responsibility center information and numbers, but MP must also include all additional information and numbers (such as overheads, allocations, third party costs, and revenues) that tie out to the FERC accounts.	Volume 2, Turner Direct at Section X.C
	All numbers should be provided on a Total Company basis, and Minnesota Jurisdictional basis, with reference and support for allocators used.	Volume 2, Turner Direct at Section X.C
	Financial schedules should fully support the test year revenue requirement. For example while transmission expenditures in a year can be helpful information, the Company needs also to provide the actual plant in service and retirement amounts that support the Company's test year.	Volume 2, Turner Direct at Section X.C

Source	Information Required	Location
	All schedules should be clearly labeled to reflect, for example, whether the schedule shows capital expenditures, capital additions and retirements, expenses, and the basis (Total Company or MN Jurisdictional).	Volume 2, Turner Direct at Section X.C
	All schedules in a rate case should break out the rider recovery and rate case recovery.	Volume 2, Turner Direct at Section X.C
E015/M-19-337	**In the Matter of Minnesota Power's Petition for Approval of its Electric Vehicle Commercial Charging Rate Pilot**	
ORDER APPROVING PILOT WITH MODIFICATIONS, AND SETTING REPORTING REQUIREMENTS (DEC. 12, 2019)	5. In its first general rate case following implementation, Minnesota Power shall show the extent to which non-participants are subsidizing participants in the Commercial Electric Vehicle Rate Pilot.	Volume 2, Peterson Direct at Section III.E
E015/D-19-534	**In the Matter of Minnesota Power's 2019 Remaining Life Depreciation Petition**	
ORDER APPROVING REMAINING LIVES AND SALVAGE RATES, REQUIRING REGULATORY LIABILITY, AND REQUIRING COMPLIANCE FILING (APR. 6, 2020)	8. Minnesota Power must establish a regulatory liability for the loader transfer from Laskin Energy Center to Rapids Energy Center, using the calculation methodology in the Company's attachment to its reply comments filed on November 14, 2019. 9. Minnesota Power must address the resulting regulatory liability in its current rate case, in Docket No. E015/GR-19-442.	Volume 2, Turner Direct at Section V.B.14
E015/M-16-564 **E015/GR-19-442**	**In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider** **In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota**	
ORDER APPROVING RIDER EXTENSION WITH CONDITIONS (JAN. 19, 2021)	1. The Commission grants Minnesota Power's August 31, 2020 petition to extend the energy-intensive trade-exposed (EITE) rider from February 1, 2021, until final rates are implemented in the Company's next rate case, expected to be filed no later than November 1, 2021, with the condition that Minnesota Power is prohibited from recovering any EITE-related costs from non-EITE customers during this time. Approval here in this order is not a determination of the appropriate treatment of the EITE discount in the rate case as it relates to future interim rates or base rates. Matters regarding whether there should be adjustments to interim or base rates because of EITE impacts are matters to be determined in the future rate case.	Volume 2, Peterson Direct at Section III.H.3

Source	Information Required	Location
	2. If Minnesota Power does not file a rate case with a 2022 test year by January 31, 2022, it will be required to terminate the current EITE rider. In this contingency, Minnesota Power shall make a filing on February 1, 2022, providing a detailed proposal, to be approved by the Commission, for wrapping up the current EITE rider.	N/A
E015/M-19-766	**In the Matter of Minnesota Power's Reconnect Pilot Program**	
ORDER APPROVING PILOT PROGRAM (DEC. 9, 2020)	4. Minnesota Power must provide testimony accounting for net cost changes due to remote connections in a future rate case to ensure that parties and the Commission are aware of the impacts on the representative test-year costs.	Volume 2, Gunderson Direct at Section V.C.1
E015/PA-20-839	**In the Matter of Minnesota Power's Approval of a Purchase Agreement with Spalj Real Estate, LLC**	
ORDER (JAN. 25, 2021)	4. Approved Minnesota Power's proposal to credit to customers for the amount customers will pay for the revenue requirements associated with the Crosby Service Center during the period following the sale of the property and up until the Company files its next rate case.	Volume 2, Turner Direct at Section V.B.14
	6. Required Minnesota Power to record as a regulatory liability and return as a credit to customers in the Company's next rate case (1) the gain on sale of the Crosby Service Center and (2) the amount customers will pay for the revenue requirements associated with the Crosby Service Center during the period following the sale of the property and up until the Company files its next rate case.	Volume 2, Turner Direct at Section V.B.14

Source	Information Required	Location
E015/M-16-564 **E015/GR-19-442** **E015/M-20-429**	**In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider** **In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota** **In the Matter of the Emergency Petition of Minnesota Power for Approval to Move Asset-Based Wholesale Sales Credits to the Fuel Adjustment Clause and Resolve Rate Case**	
INITIAL ORDER APPROVING PETITION AND RESOLVING RATE CASE WITH CONDITIONS (JUNE 30, 2020) ORDER APPROVING PETITION AND RESOLVING RATE CASE WITH CONDITIONS (AUG. 7, 2020)[3]	1.C. In its next rate case, Minnesota Power shall submit information on its process for collecting residential late fees and the costs expended in these collection efforts.	Volume 2, Peterson Direct at Section III.B.2
	1.B. Before its next rate case, Minnesota Power shall ensure that parties can modify the Company's class cost-of-service study model inputs and cost allocators to allow parties to receive real-time calculations and outputs. The Company shall also track and report any costs related to complying with this requirement.	Volume 2, Shimmin Direct at Section II
E,G999/CI-20-492	**In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic**	
ORDER ACCEPTING ECONOMIC RECOVERY INVESTMENT REPORTS, REQUIRING FILINGS, AND ENCOURAGING ADVANCEMENT OF DIVERSITY GOALS (MAR. 16, 2021)	2. Utilities shall track investments separately from base rates to ensure transparency of the recovery process.	Volume 2, Rostollan Direct at Section IV.E

[3] While both orders provided the same order points, the wording in each order was slightly different. This table reflects the language from the August 7, 2020 Commission order.

Source	Information Required	Location
E,G999/CI-20-425 **E,G999/M-20-427**	**In the Matter of an Inquiry into the Financial Effects of COVID-19 on Natural Gas and Electric Utilities** **In the Matter of the Petition of the Minnesota Rate Regulated Electric and Gas Utilities for Authorization to Track Expenses Resulting from the Effects of the COVID-19 and Record and Defer Such Expenses into a Regulatory Asset**	
ORDER APPROVING ACCOUNTING REQUEST AND TAKING OTHER ACTION RELATED TO COVID-19 PANDEMIC (MAY 22, 2020)	5. The Joint Petitioners' April 20, 2020 Petition [requesting authority to track, defer, and record COVID-19 related expenses as a regulatory asset] is granted with the caveat that the grant is for accounting purposes only. Further, the utilities must track costs and revenues or grants incurred or received as a result of the COVID-19 pandemic. They must make an initial filing of their accounting methodology and known and estimated costs and revenues within the specific categories in 21 days, and quarterly thereafter. The utilities still bear the burden to establish significance, reasonableness, prudence, and the incremental nature of the costs.	Volume 2, Rostollan Direct at Section IV.E
E015/D-20-701	**In the Matter of Minnesota Power's 2020 Remaining Life Depreciation Petition**	
ORDER (MAR. 24, 2021)	4. Required that MP, in its next rate case, include the regulatory liability resulting from the loader transfer described in the Commission's April 6, 2020 Order in Docket No. E015/D-19-534 and identify in its initial filing in that case where the regulatory liability is discussed.	Volume 2, Turner Direct at Section V.B.14
E015/M-20-557	**In the Matter of the Petition by Minnesota Power (MP) for Approval of its 2020 Solar Renewable Factor within its Renewable Resources Rider**	
ORDER (APR. 20, 2021)	Comments of the Department of Commerce (adopted by the Commission) Section III.H: In conversations with Minnesota Power, the Department learned that MP does not anticipate rolling its solar projects into proposed base rates in a future rate case. Instead, since certain large industrial customers are exempt from the SES, the Company plans to keep its solar costs in the RRR. Therefore, the Department concludes that determining how to coordinate the Solar Renewable Factor recovery with MP's next future rate case is unnecessary at this time, but should be considered in the subsequent rate case, including the question as to whether the costs should be recovered in a rider or base rates.	Volume 2, Turner Direct at Section V.B.23 and Schedule 2

Source	Information Required	Location
E015/M-19-440	**In the Matter of Minnesota Power's Request for Approval of its 2019 Transmission Factors under its Transmission Cost Recovery Rider**	
ORDER (MAY 18, 2021)	2. Required Minnesota Power to provide testimony in its next rate case addressing how the Company has ensured that the overall classification of expenses is appropriate and consistent with FERC requirements, which Minnesota has adopted.	Volume 2, Gunderson Direct at Section IV.A Volume 2, Rostollan Direct at Section II.A
E015/D-21-229	**In the Matter of Minnesota Power's 2021 Intangible, Transmission, Distribution, and General Plant Depreciation Petition**	
ORDER (AUG. 2, 2021)	MP Comment in Response to DOC IR (Attached to DOC Comments adopted by the Commission): "Minnesota Power filed its current five-year depreciation study earlier than required per Commission order (May 1, 2022) primarily due to over $300 million of Great Northern Transmission Line (GNTL) assets being placed into service in 2020. The Great Northern Transmission Line is an approximately 220-mile 500-kV transmission line from near Grand Rapids, Minnesota, to the Canadian border. The GNTL transmission assets are expected to have longer lives than the existing transmission assets, and extending the lives decreases depreciation expense. Minnesota Power would like to incorporate the Commission approved depreciation rates from this study into its expected rate case filing by November 2021."	Volume 2, Rostollan Direct at Section II.E
E015/M-20-850 **E015/M-12-233**	**In the Matter of the Petition for Approval of Minnesota Power's Residential Rate Design** **In the Matter of Minnesota Power's Compliance Report for its Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advance Metering Infrastructure Pilot Project**	
ORDER APPROVING TRANSITION FROM INVERTED BLOCK RATE TO TIME-OF-DAY RATES (AUG. 27, 2021)	1.c. The Commission approves Minnesota Power's: Implementation of the phased conversion from inverted block rate to a transitional flat rate, so rate design changes can begin to be implemented ahead of the Minnesota Power's next rate case.	Volume 2, Peterson Direct at Section III.B

Additional Compliance Items from E015/GR-16-664

Source	Information Required	Compliance Filing
E015/GR-16-664	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
FINDINGS OF FACT, CONCLUSIONS, AND ORDER (MAR. 12, 2018)		
Order Point 22	The Company shall continue to provide customer refunds in the event that actual Annual Incentive Program (AIP) payouts are lower than the level approved in rates.	July 23, 2019 filing in Docket No. E015/GR-16-664 eDocket Document ID 20197-154598-01 August 18, 2020 filing in Docket No. E015/GR-16-664 eDocket Document ID 20208-165980-01 March 15, 2021 filing in Docket No. E015/GR-16-664 eDocket Document ID 20213-171886-01 June 30, 2021 filing in Docket No. E015/GR-16-664 eDocket Document ID 20216-175677-01 Volume 2, Krollman Direct at Section III.B
Order Point 37	True-up annually in the renewable rider PTCs approved in the test year and associated ADIT.	Volume 2, Armbruster Direct at Section III
Order Point 54	Work with interested parties to improve transparency in future MP class cost of service studies. Submit within 12 months a compliance filing explaining the improvements including the updated CCOSS version and guide or if not yet completed at the 12 month deadline, a timeline for completion and future compliance filings.	May 22, 2019 filing in Docket No. E015/GR-16-664 eDocket Document ID 20195-153092-01 Volume 2, Shimmin Direct at Section II
Order Point 55	MP must file a status report within six months of this order, which will identify the Company's efforts to that date to facilitate review of its CCOSS model or adopt a new model. The parties shall also consider the concerns raised by the Commission staff.	November 29, 2018 filing in Docket No. E015/GR-16-664 eDocket Document ID 201811-148068-01 Volume 2, Shimmin Direct at Section II

Source	Information Required	Compliance Filing
E015/GR-16-664	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
Order Point 72	The Company shall work with LPI and other stakeholders to develop a demand response rider and corresponding methodology for cost recovery based on stakeholder input. The record to support the submission may be developed in either Docket E015/AI-17-568 – OAH Docket 68-2500-34672 or a miscellaneous docket. If MP, LPI, and other stakeholders elect to proceed with a new miscellaneous docket, such filing shall be submitted for Commission approval within six months after the date of the final written order.	December 7, 2018 filing in Docket No. E015/M-18-735 eDocket Document ID 201812-148328-01 Volume 2, Frederickson Direct at Section II.C Volume 2, Turner Direct at Sections V.B.27 and V.B.28
Order Point 78(e)	The Company shall file by May 1 each year (in a new miscellaneous docket) an annual compliance filing to show the number of customers served on the Business Development Incentive Rider, together with each customer's incremental revenue and costs; and energy audits should be required for all Rider customers.	April 30, 2019 filing in Docket No. E015/M-19-295 eDocket Document ID 20194-152519-01 April 30, 2020 filing in Docket No. E015/M-20-445 eDocket Document ID 20204-162730-01 April 29, 2021 filing in Docket No. E015/M-21-296 eDocket Document ID 20214-173579-01
Order Point 80(b)	Provide annual updates about the Green Pricing Program (including information on participation, administration costs, and certification costs) to monitor the price of the program.	July 10, 2019 filing in Docket No. E015/GR-16-664 eDocket Document ID 20197-154263-01 July 24, 2020 filing in Docket No. E015/GR-16-664 eDocket Document ID 20207-165238-01 August 20, 2021 filing in Docket No. E015/GR-16-664 eDocket Document ID 20218-177329-01
Order Point 80(c)	Not apply the Fuel Clause Adjustment (which includes the Base Cost of Energy at $21.21/MWh and the Rider for Fuel and Purchased Power) to the portion of renewable energy reserved by customers participating in the Company's green pricing program	December 12, 2018 filing in Docket No. E015/GR-16-664 eDocket Document ID 201812-148409-01 201812-148409-02 (TS)

Source	Information Required	Compliance Filing
E015/GR-16-664	**In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota**	
Order Point 80(d)	Require MP to file a proposal as to how to address the situation where the price of renewable PPAs become consistently lower than the price of MP's overall power mix or consider now, or in the future, whether it may be a reasonable policy to charge customers participating in the green pricing program a lower rate if the price of renewable energy resources used for the program drops below the price for MP's existing resource mix.	November 29, 2018 filing in Docket No. E015/GR-16-664 eDocket Document ID 201811-148114-01
Order Point 81	MP is ordered to work with Wal-Mart and any other interested stakeholders to develop one or more renewable programs suitable for large customers and report to the Commission the results of such development within six months of the date of this order.	August 9, 2019 filing in Docket No. E015/GR-16-664 eDocket Document ID 20198-155081-01 November 29, 2018 filing in Docket No. E015/GR-16-664 eDocket Document ID 201811-148114-02
ORDER GRANTING RECONSIDERATION IN PART, REVISING MARCH 12, 2018 ORDER, AND OTHERWISE DENYING RECONSIDERATION PETITIONS (MAY 29, 2018)	Order Point 1.C. In lieu of a securitization plan, the Company shall continue to explore securitization and, within two years of the date of this order, file a report on securitization, informed by the input of stakeholders, including the OAG and the Clean Energy Organizations	October 1, 2020 filing in Docket No. E015/GR-16-664 eDocket Document ID 202010-167012-02 February 5, 2021 filing in Docket No. E015/RP-21-33 eDocket Document ID 20212-170750-01
E015/M-21-28	**In the Matter of the Petition by Minnesota Power for Approval of its Industrial Demand Response Product C Contracts**	
ORDER ESTABLISHING PILOT PROGRAM	Order Point 4.C: In the upcoming rate case, MP shall identify any cost allocation impacts caused by Product C and explain the ratemaking treatment and implications of the program in detail.	Minnesota Power will address in rebuttal testimony as discussed during the September 23, 2021 agenda hearing.

Additional Compliance Items from E015/M-16-564, E015/GR-19-442 and E015/M-20-429

Source	Information Required	Compliance Filing
E015/M-16-564 **E015-GR-19-442** **E015/M-20-429**	**In the Matter of Minnesota Power's Revised Petition for a Competitive Rate for Energy-Intensive Trade-Exposed (EITE) Customers and an EITE Cost Recovery Rider** **In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota** **In the Matter of the Emergency Petition of Minnesota Power for Approval to Move Asset-Based Wholesale Sales Credits to the Fuel Adjustment Clause and Resolve Rate Case**	
INITIAL ORDER APPROVING PETITION AND RESOLVING RATE CASE WITH CONDITIONS (JUNE 30, 2020) ORDER APPROVING PETITION AND RESOLVING RATE CASE WITH CONDITIONS (AUG. 7, 2020)[4]	2.A. Regarding rate design, Minnesota Power shall … [a]ddress issues of residential rate design issues in Docket No. E-015/M-12-233, *In the Matter of Minnesota Power's Compliance Report for its Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project.*	December 1, 2020 filing in Docket No. E015/M-12-233 eDocket Document ID 202012-168680-01 202012-168680-02 202012-168680-03 202012-168680-04 202012-168680-05 202012-168680-06 202012-168680-07 December 1, 2020 filing in Docket No. E015/M-20-850 202012-168679-01 202012-168679-02 202012-168679-03 202012-168679-04 202012-168679-05 202012-168679-06 202012-168679-07
	2.B. Regarding rate design, Minnesota Power shall … Work with its Large Light & Power customers on rate design alternatives and file a report on those discussions within six months.	December 22, 2020 filing in Docket No. E015/M-20-429 eDocket Document ID 202012-169301-01 December 22, 2020 filing in Docket No. E015/GR-19-442 eDocket Document ID 202012-169301-02

[4] While both orders provided the same order points, the wording in each order was slightly different. This table reflects the language from the August 7, 2020 Commission order.

Source	Information Required	Compliance Filing
	2.C. Regarding rate design, Minnesota Power shall … Work with its Large Power customers on rate design alternatives and file a report on those discussions within six months.	December 22, 2020 filing in Docket No. E015/GR-19-442 eDocket Document ID 202012-169300-01 December 22, 2020 filing in Docket No. E015/M-20-429 eDocket Document ID 202012-169300-02
	2.D. Regarding rate design, Minnesota Power shall … [m]aintain the current Energy-Intensive Trade-Exposed Customer rate discount through February 1, 2021, and work with stakeholders to bring forward a proposal by August 31, 2020, to extend the EITE rate discount.	August 31, 2020 filing in Docket No. E015/M-16-564 eDocket Document ID 20208-166307-01 (TS) 20208-166307-02 September 8, 2020 filing in Docket No. E015/M-20-429 eDocket Document ID 20209-166462-02 20209-166462-04 (TS) September 8, 2020 filing in Docket No. E015/M-20-429 eDocket Document ID 20209-166462-01 20209-166462-03 (TS)

Source	Information Required	Compliance Filing
	3. Minnesota Power shall submit a compliance filing within ten days including – (A) final rates and all related tariff changes; (B) supporting spreadsheets with formulas; and (C) a brief narrative explaining all changes to the rate calculations made since Minnesota power's April 30, 2020 supplemental filing in this docket.	July 1, 10, and 17, 2020 filing in Docket No. E015/M-16-564 eDocket Document ID 20207-164500-03 20207-164822-01 20207-164822-04 (TS) 20207-164822-07 (TS) 20207-165051-02 20207-165051-05 20207-165051-08 (TS) July 1, 6, 10, and 17, 2020 filings in Docket No. E015/GR-19-442 eDocket Document ID 20207-164500-01 20207-164665-03 20207-164822-02 20207-164822-05 (TS) 20207-164822-08 (TS) 20207-165051-03 20207-165051-06 20207-165051-09 (TS) July 1, 6, 10, and 17, 2020 filing in Docket No. E015/M-20-429 eDocket Document ID 20207-164500-02 20207-164665-01 20207-164822-03 20207-164822-06 (TS) 20207-164822-09 (TS) 20207-165051-01 20207-165051-04 20207-165051-07 (TS)

IN THE MATTER OF THE APPLICATION OF MINNESOTA POWER FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN MINNESOTA

MPUC DOCKET NO. E015/GR-21-335

CERTIFICATE OF SERVICE

I, Kodi J. Verhalen, hereby certify that on the 1st day of November, 2021, on behalf of Minnesota Power, I electronically filed a true and correct copy of **Minnesota Power's Application for Authority to Increase Electric Service Rates in Minnesota** on www.edockets.state.mn.us. A summary of the filing was provided via electronic service or United States First Class Mail as designed on the enclosed service list.

Dated this 1st day of November, 2021

/s/ Kodi J. Verhalen

Kodi J. Verhalen

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lori	Andresen	info@sosbluewaters.org	Save Our Sky Blue Waters	P.O. Box 3661 Duluth, Minnesota 55803	Electronic Service	No	OFF_SL_21-335_GR-21-335
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_21-335_GR-21-335
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-335_GR-21-335
Sara	Bergan	sebergan@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Kristin	Berkland	kristin.berkland@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
David F.	Boehm	dboehm@bkllawfirm.com	Boehm, Kurtz & Lowry	36 E 7th St Ste 1510 Cincinnati, OH 45202	Electronic Service	No	OFF_SL_21-335_GR-21-335
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_21-335_GR-21-335
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_21-335_GR-21-335
David	Cartella	David.Cartella@cliffsnr.com	Cliffs Natural Resources Inc.	200 Public Square Ste 3300 Cleveland, OH 44114-2315	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Greg	Chandler	greg.chandler@upm.com	UPM Blandin Paper	115 SW First St Grand Rapids, MN 55744	Electronic Service	No	OFF_SL_21-335_GR-21-335
Steve W.	Chriss	Stephen.chriss@walmart.com	Wal-Mart	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_21-335_GR-21-335
Sean	Copeland	seancopeland@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Rd Cloquet, MN 55720	Electronic Service	No	OFF_SL_21-335_GR-21-335
Hillary	Creurer	hcreurer@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
Lisa	Daniels	lisadaniels@windustry.org	Windustry	201 Ridgewood Ave Minneapolis, MN 55403	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Ron	Elwood	relwood@mnlsap.org	Mid-Minnesota Legal Aid	2324 University Ave Ste 101 Saint Paul, MN 55114	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-335_GR-21-335
John R.	Gasele	jgasele@fryberger.com	Fryberger Buchanan Smith & Frederick PA	700 Lonsdale Building 302 W Superior St Ste 700 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-335_GR-21-335
Barbara	Gervais	toftemn@boreal.org	Town of Tofte	P O Box 2293 7240 Tofte Park Road Tofte, MN 55615	Electronic Service	No	OFF_SL_21-335_GR-21-335
Jerome	Hall	hallj@stlouiscountymn.gov	Saint Louis County Property Mgmt Dept	Duluth Courthouse 100 N 5th Ave W Rm 515 Duluth, MN 55802-1209	Electronic Service	No	OFF_SL_21-335_GR-21-335
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_21-335_GR-21-335
Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S. Eighth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
James	Jarvi	N/A	Minnesota Ore Operations - U S Steel	P O Box 417 Mountain Iron, MN 55768	Paper Service	No	OFF_SL_21-335_GR-21-335
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_21-335_GR-21-335
Kelsey	Johnson	info@taconite.org	Iron Mining Association	324 West Superior St Ste 502 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Nicolas	Kaylor	nkaylor@mojlaw.com		120 South 6th St Ste 2400 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Travis	Kolari	N/A	Keetac	PO Box 217 Keewatin, MN 55753	Paper Service	No	OFF_SL_21-335_GR-21-335
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Becky	Lammi	cityclerk@ci.aurora.mn.us	City of Aurora	16 W 2nd Ave N PO Box 160 Aurura, MN 55705	Electronic Service	No	OFF_SL_21-335_GR-21-335
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
David	Langmo	david.langmo@sappi.com	Sappi North America	P O Box 511 2201 Avenue B Cloquet, MN 55720	Electronic Service	No	OFF_SL_21-335_GR-21-335
Emily	Larson	eLarson@duluthmn.gov	City of Duluth	411 W 1st St Rm 403 Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
LeRoger	Lind	llind@yahoo.com	Save Lake Superior Association	P.O. Box 101 Two Harbors, MN 55616	Electronic Service	No	OFF_SL_21-335_GR-21-335
Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 Saint Paul, MN 55104-3435	Electronic Service	No	OFF_SL_21-335_GR-21-335
Patrick	Loupin	PatrickLoupin@PackagingCorp.com	Packaging Corporation of America	PO Box 990050 Boise, ID 83799-0050	Electronic Service	No	OFF_SL_21-335_GR-21-335
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-335_GR-21-335
Sarah	Manchester	sarah.manchester@sappi.com	Sappi North American	255 State Street Floor 4 Boston, MA 02109-2617	Electronic Service	No	OFF_SL_21-335_GR-21-335
Emily	Marshall	emarshall@mojlaw.com	Miller O'Brien Jensen, PA	120 S. 6th Street Suite 2400 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-335_GR-21-335
Keith	Matzdorf	keith.matzdorf@sappi.com	Sappi Fine Paper North America	PO Box 511 2201 Avenue B Cloquet, MN 55720	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_21-335_GR-21-335
Matthew	McClincy	MMcClincy@usg.com	USG	35 Arch Street Clouqet, MN 55720	Electronic Service	No	OFF_SL_21-335_GR-21-335
Craig	McDonnell	Craig.McDonnell@state.mn.us	MN Pollution Control Agency	520 Lafayette Road St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires	570 Asbury St Ste 201 Saint Paul, MN 55104-1850	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_21-335_GR-21-335
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Noble	noble@fresh-energy.org	Fresh Energy	408 Saint Peter St Ste 350 Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-335_GR-21-335
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_21-335_GR-21-335
M. William	O'Brien	bobrien@mojlaw.com	Miller O'Brien Jensen, P.A.	120 S 6th St Ste 2400 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Christopher J.	Oppitz	N/A	-	110 1/2 1ST ST E Park Rapids, MN 56470-1695	Paper Service	No	OFF_SL_21-335_GR-21-335
Elanne	Palcich	epalcich@cpinternet.com	Save Our Sky Blue Waters	P.O. Box 3661 Duluth, MN 55803	Electronic Service	No	OFF_SL_21-335_GR-21-335
Max	Peters	maxp@cohasset-mn.com	City of Cohasset	305 NW First Ave Cohasset, MN 55721	Electronic Service	No	OFF_SL_21-335_GR-21-335
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
William	Phillips	wphillips@aarp.org	AARP	30 E. 7th St Suite 1200 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power	30 W Superior S Duluth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
Tolaver	Rapp	Tolaver.Rapp@cliffsnr.com	Cliffs Natural Resources	200 Public Square Suite 3400 Cleveland, OH 441142318	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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_21-335_GR-21-335
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_21-335_GR-21-335
Ralph	Riberich	rriberich@uss.com	United States Steel Corp	600 Grant St Ste 2028 Pittsburgh, PA 15219	Electronic Service	No	OFF_SL_21-335_GR-21-335
Buddy	Robinson	buddy@citizensfed.org	Minnesota Citizens Federation NE	2110 W. 1st Street Duluth, MN 55806	Electronic Service	No	OFF_SL_21-335_GR-21-335
Santi	Romani	N/A	United Taconite	PO Box 180 Eveleth, MN 55734	Paper Service	No	OFF_SL_21-335_GR-21-335
Susan	Romans	sromans@allete.com	Minnesota Power	30 West Superior Street Legal Dept Duulth, MN 55802	Electronic Service	No	OFF_SL_21-335_GR-21-335
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_21-335_GR-21-335
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_21-335_GR-21-335
Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC	1742 Patriot Rd Northfield, MN 55057	Electronic Service	No	OFF_SL_21-335_GR-21-335

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_21-335_GR-21-335
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_21-335_GR-21-335
Brett	Skyles	Brett.Skyles@co.itasca.mn.us	Itasca County	123 NE Fourth Street Grand Rapids, MN 557442600	Electronic Service	No	OFF_SL_21-335_GR-21-335
Richard	Staffon	rcstaffon@msn.com	W. J. McCabe Chapter, Izaak Walton League of America	1405 Lawrence Road Cloquet, Minnesota 55720	Electronic Service	No	OFF_SL_21-335_GR-21-335
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_21-335_GR-21-335
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_21-335_GR-21-335
Robert	Tammen	bobtammen@frontiernet.net	Wetland Action Group	PO Box 398 Soudan, MN 55782	Electronic Service	No	OFF_SL_21-335_GR-21-335
Jim	Tieberg	jtieberg@polymetmining.com	PolyMet Mining, Inc.	PO Box 475 County Highway 666 Hoyt Lakes, MN 55750	Electronic Service	No	OFF_SL_21-335_GR-21-335
Jessica	Tritsch	jessica.tritsch@sierraclub.org	Sierra Club	2327 E Franklin Ave Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-335_GR-21-335

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_21-335_GR-21-335
Kodi	Verhalen	kverhalen@taftlaw.com	Taft Stettinius & Hollister LLP	80 S 8th St Ste 2200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-335_GR-21-335
Kevin	Walli	kwalli@fryberger.com	Fryberger, Buchanan, Smith & Frederick	380 St. Peter St Ste 710 St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-335_GR-21-335
Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club	Environmental Law Program 1536 Wynkoop St Ste 200 Denver, CO 80202	Electronic Service	No	OFF_SL_21-335_GR-21-335
Cha	Xiong	cha.xiong@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St. Suite 1400 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_21-335_GR-21-335
Scott	Zahorik	scott.zahorik@aeoa.org	Arrowhead Economic Opportunity Agency	702 S. 3rd Avenue Virginia, MN 55792	Electronic Service	No	OFF_SL_21-335_GR-21-335