Direct Testimony and Schedules
Amanda L. Turner

Before the Minnesota Public Utilities Commission

State of Minnesota

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

Exhibit ________

REVENUE REQUIREMENTS

November 1, 2021

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Amanda Turner, and my business address is 30 West Superior Street, Duluth, Minnesota, 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Costing and Pricing Analyst II.

Q. Please describe your educational background and work experience with Minnesota Power.

A. I have a Bachelor of Science in Mathematics from the College of Saint Scholastica. I have seven years of experience in revenue requirements. I am currently responsible for maintaining Minnesota Power's UIPlanner application, which includes the Company's Class Cost of Service Study ("CCOSS") model, as well as coordinating revenue requirement support for general rate cases, other financial regulatory filings, and projects.

Q. What is the purpose and scope of your testimony?

A. The purpose of my testimony is to support Minnesota Power's revenue requirements for the test year consisting of calendar year 2022. Specifically, my testimony addresses the determination of rate base and operating income. My testimony also discusses the treatment of adjustments made in the Interim and Adjusted Test Year CCOSSs and supports the determination of the Minnesota Jurisdictional revenue increase required by Minnesota Power to earn its requested rate of return in the Adjusted Test Year and the allowed rate of return in the Interim Test Year. Additionally, I explain how the Company's cost recovery riders and tracker balances bear on our 2022 test year cost of service, building on the detailed testimony of Company witnesses Stewart J. Shimmin and John D. Armbruster. In particular, I support the Company's Conservation Improvement Program ("CIP") tracker and base rate totals. Finally, I address several compliance items from other dockets.

Q. What schedules are you sponsoring in your testimony?

A. I am sponsoring the following schedules that immediately follow my testimony and are identified as:

- Exhibit ___ (Turner) Direct Schedule 1, Summary of Proposed Increase to Interim and General Rate Revenues;
- Exhibit ___ (Turner) Direct Schedule 2, Revenue Credits Summary (Trade Secret); and
- Exhibit ___ (Turner) Direct Schedule 3, Rate Case Adjustments.

II. SUMMARY OF RATE CHANGE REQUEST

Q. Please summarize Minnesota Power's proposed increase to Interim and General Rate revenues in this proceeding.

A. Minnesota Power proposes an Interim Rate increase of $87.3 million (14.23 percent) (MN Jurisdictional[1]) and a General Rate increase of $108.3 million (17.58 percent) (MN Jurisdictional). The General Rate and Interim Rate revenue requirements, revenue deficiency, and proposed rate increase percentage are summarized on MP Exhibit ___ (Turner), Direct Schedule 1 to my testimony. Additionally, Volume 1 Schedule A-1 (IR) and Volume 3 Schedule A-1 summarize Minnesota Power's proposed Interim Rate and General Rate revenues, respectively.

Q. Please identify the fiscal periods for which Minnesota Power is providing financial data in this filing.

A. Financial data is provided for calendar year 2020 as the most recent fiscal year[2]; for

[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided in Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16.

[2] 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 and 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 fiscal year." 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 nine months of historical data is available, consistent with Minn. Rule 7825.3100, Subd. 10. If the Commission believes it is necessary to grant a variance to utilize this definition of the "most recent fiscal year," the Company requests a variance under Minn. Rule 7829.3200, because (i) it would be an excessive burden on the utility to have to wait to file a case until nine months of 2021 data is

calendar year 2021 as the projected fiscal year[3]; and for calendar year 2022 as the test year.[4] Consistent with Minnesota Rules, the Company provides average rate base, operating income, overall rate of return, and the calculation of revenue deficiency for the fiscal periods as shown in Table 1, below.

Table 1: Fiscal Periods Included in Filing

Fiscal Period	Calendar Year	Schedule or Workpaper Reference
Most Recent Fiscal Year	2020	Volume 4 COS-4
Projected Fiscal Year	2021	Volume 4 COS-3
Unadjusted Test Year	2022	Volume 4 COS-2
Interim Test Year	2022	Volume 4 COS-1
Adjusted Test Year	2022	Volume 3 Direct Schedule E-3

Q. Why is the 2022 calendar year the appropriate test year for this proceeding?

A. The test year begins on the proposed effective date for interim rates, which is January 1, 2022. Use of this test year results in appropriate matching of Minnesota Power's costs with the revenues that are proposed to be collected under interim and final rates. Use of a budgeted test year is also consistent with what the Minnesota Public Utilities Commission ("Commission") approved in Minnesota Power's 2016 rate case in Docket No. E015/GR-16-664 ("2016 Rate Case"). Further, Minnesota Power has presented a projected test year in all of its prior completed retail rate cases in Minnesota, including Docket Nos. E015/GR-16-664 (calendar year 2017); E015/GR-09-1151 (calendar year 2010), E015/GR-08-415 (July 1, 2008 through June 30, 2009), E015/GR-94-001 (calendar year 1994), E015/GR-87-223 (July 1, 1987 through June 30, 1988),

available, given the amount of time required to prepare a rate case filing; (ii) the variance would not adversely affect the public interest given that the Rule contemplates using the prior calendar year as the most recent fiscal year, and this has been Minnesota Power's practice for decades; and (iii) the variance would not conflict with standards imposed by law because it is consistent with Minn. Rule 7825.3100 and with past practice.

[3] Minn. Rule 7825.3100, Subp. 12 defines "Projected fiscal year" as "the fiscal year immediately following the most recent fiscal year."

[4] Minn. Rule 7825.3100, Subp. 17 defines "Test year" as "the 12-month period selected by the utility for the purpose of expressing its need for a change in rates."

E015/GR-81-250 (July 1, 1981 through June 30, 1982), E015/GR-80-76 (May 1, 1980 through April 30, 1981), E015/GR-78-514 (July 1, 1978 through June 30, 1979), E015/GR-77-360 (May 1, 1977 through April 30, 1978), and E015/GR-76-408 (calendar year 1976).

Q. Why is it necessary for the Company to conduct different CCOSSs for the Interim Test Year and the Adjusted Test Year?

A. As explained in more detail in Section V of my testimony, there are several differences between what has been previously approved by the Commission — and, therefore, the basis of the Interim Test Year CCOSS under Minn. Stat. §216B.16, subd. 3 — and what is being proposed by the Company in this proceeding. These differences include allocator methodology, return on common equity ("ROE"), and various rate case adjustments.

Q. Is Minnesota Power requesting any exceptions to the application of Interim Rates?

A. No. As described in the Company's Petition for Interim Rates in Volume I, Minnesota Power requests that the proposed interim rate increase be applied to all classes of Minnesota Power's retail electric customers, consistent with the rate design established in the Company's 2016 Rate Case and Minn. Stat. §216B.16, subd. 3. As noted in the Company's Petition for Interim Rates, however, the interim rate increase is not applied to Large Power Incremental Production Service ("LP IPS"), Economy, Replacement Firm Power Service ("RFPS"), and service fees. Revenue associated with these rate components is not considered part of the Large Power class revenue in the CCOSS, and these services are priced based on Minnesota Power's hourly incremental energy cost or other separately-negotiated terms.

III. RATE BASE

Q. Please list the major components of rate base.

A. The major components of rate base are: Plant in Service, Construction Work in Progress ("CWIP"), Accumulated Depreciation and Amortization, and Working

Capital (including Fuel Inventory, Materials and Supplies, Prepayments, and Cash Working Capital). Net Plant and Cash Working Capital are discussed in more detail below. In addition, rate base includes several smaller items: Workers' Compensation Deposit, Unamortized Wisconsin Public Power, Inc. Energy Transmission Amortization, Unamortized Upper Midwest Wind Initiative Transaction Cost, Customer Advances and Deposits, Other Deferred Credits – Hibbard, Wind Performance Deposit, and Accumulated Deferred Income Taxes.

Q. Please generally discuss the development of Unadjusted Test Year rate base in this proceeding.

A. Unadjusted Test Year rate base was developed using costs from calendar year 2020 and updated costs for 2021 and a forecast for the remainder of 2021 and 2022. Minnesota Power witness Joshua G. Rostollan explains Minnesota Power's methodology for overall budget development in his Direct Testimony.

Q. Are there rate case adjustments applicable to rate base in the test year in this proceeding?

A. Yes, all rate case adjustments are discussed in Section V of my testimony.

A. Net Plant

Q. How was the Unadjusted Test Year net plant developed?

A. Net Plant is made up of Plant in Service, CWIP, Accumulated Depreciation, and Accumulated Amortization. Plant in Service is measured at original cost depreciated and based on the average of beginning and ending balances of the test year. Plant in Service for the test year was developed beginning with December 2020 plant balances by major function. Added to these amounts were forecast additions and retirements for 2021 and 2022 from the 2022 construction budget to arrive at average plant balances. These plant additions and retirements are also the basis for development of test year depreciation expense and, therefore, the accumulated provision for depreciation and amortization. CWIP was also obtained from actual December 2020 balances, adjusted for additions to CWIP and transfers to plant for 2021 and 2022 from the construction budget information.

B. Cash Working Capital

Q. How have you defined Cash Working Capital?

A. Cash Working capital, for purposes of this proceeding, is defined as the amount of capital investors must provide to the Company, in addition to their investment in utility rate base, to meet cash payment requirements during the period after expenditures are made to provide service and before the collection of revenues for that service. Thus, Cash Working Capital represents the amount of money needed to meet current operating expenses incurred prior to collecting revenues for the service provided.

When investors supply these funds, they are entitled to a return on these advances. To the extent these funds are supplied by customers, customers are entitled to have their contribution recognized as a rate base deduction. This is accomplished by including an appropriate Cash Working Capital requirement in rate base. The elements of Cash Working Capital included in this proceeding are consistent with those allowed by the Commission in each of the Company's most recent retail rate cases. As stated in its June 14, 1982 Statement of Policy on Cash Working Capital, the Commission recognizes that the most precise method of determining the Cash Working Capital requirements is to perform a lead-lag study.

Q. What procedures were followed in the preparation of the lead-lag study used in this proceeding?

A. The procedures used in the lead-lag study were initially developed to support the Company's request for a Cash Working Capital allowance in Docket No. E015/GR-78-514, which the Commission approved. The same lead-lag study methodology, adjusted to reflect various minor changes in procedures such as required payment due dates, was also the basis for the determination of Cash Working Capital in Docket Nos. E015/GR-80-76, E015/GR-81-250, E015/GR-87-223, E015/GR-94-001, E015/GR-08-415, E015/GR-09-1151, and E015/GR-16-664. The Cash Working Capital allowances were approved in these seven dockets with minor or no adjustments.

For this proceeding, the established lead-lag periods were determined based on a detailed study of the actual lead days and lag days experienced by the Company during calendar year 2019. Patterns in the payment of expenses and receipt of revenues do not vary significantly from one year to another. In 2018, the Company changed its standard payment terms from Net 30 to Net 60 in order to improve the Company's cash flow and Cash Working Capital. This change in standard payment terms pertains to accounts payable from the Company to its vendors, rather than payments from customers to the Company. Not all current vendors have been put on or have agreed to move to the new standard payment terms, and they have the ability to negotiate other payment terms if the new terms are not agreeable to them. However, new vendors and/or new contracts are being moved to the Company's new payment terms. The Company reviewed procedures currently in effect and identified no significant changes in policies or procedures that would affect the validity of the lead-lag periods experienced during or anticipated for 2020, 2021, or the 2022 test year.

Overall, the 2019 lead-lag study and resulting Cash Working Capital calculation are consistent with the approach and methodology approved by the Commission in the 2016 Rate Case, which was based on a 2012 lead-lag study. The details of the 2019 lead-lag study are included in Volume 4, Workpaper OS – 2.

Q. How have the results of the Company's lead-lag study been used in this proceeding?

A. The results of this study have been applied to data in the CCOSS for each fiscal year to determine the Cash Working Capital components of rate base.

Q. Do you anticipate any changes to the Cash Working Capital calculation during the course of the rate case proceeding?

A. Yes. As in Minnesota Power's previous retail rate cases, Cash Working Capital will need to be recalculated to reflect any changes in the Company's request during the course of the case, as well as for the Commission-approved financial adjustments that impact operations and maintenance ("O&M") expenses, rate base, and/or capital structure. As such, Cash Working Capital is likely to change over the course of this proceeding.

IV. OPERATING INCOME

A. <u>Test Year Revenue and Expense</u>

Q. Please explain the basis for Unadjusted Test Year revenues and expenses.

A. The 2022 Operating Budget provides the basis for energy sales, revenues, O&M expenses, depreciation expense, amortization expense, property taxes, payroll taxes, environmental taxes, investment tax credit, and allowance for funds used during construction ("AFUDC"). Retail revenues from electricity sales used in the Unadjusted Test Year CCOSS reflect the final rates ordered in the Company's most recent rate case in Docket No. E015/GR-16-664 and as amended by the resolution of the Company's 2019 Rate Case in Docket Nos. E015/M-20-429 and E015/GR-19-442. These sales were developed based on budgeted sales of electricity in the 2022 Revenue Budget, as discussed in more detail by Company witness Benjamin S. Levine. Income taxes are calculated based on operating revenues and expenses, plus necessary adjustments to pretax income. The adjustments to pretax income, along with deferred income taxes and the tax credits, were developed by the Company's Tax Department based on budget data reflected in the CCOSS. AFUDC reflects interest charged on CWIP projects during the test year.

Q. How are Wheeling Revenues handled in the CCOSS?

A. Wheeling revenues from Minnesota Power's wholesale transmission customers Staples, Wadena, and Great River Energy are included in the FERC Jurisdiction for CCOSS purposes.

Q. Are there rate case adjustments applicable to operating income in the test tear in this proceeding?

A. Yes, all rate case adjustments are discussed in Section V of my testimony.

B. Revenue Credits

Q. Please summarize the revenue credits that are included in the cost-of-service study.

A. The revenue credits for the 2022 test year are summarized in Exhibit ___ (Turner), Direct Schedule 2. There are several major categories of revenue credits, including:

1) Retail Non-firm and Other Industrial;
    1. Residential and Commercial/Industrial Dual Fuel;
    2. LP Intersystem Sales (LP IPS, Economy, RFPS);
2) Sales for Resale (Off-System);
3) Other Operating Revenue;
    1. Production;
    2. Transmission;
    3. Distribution;
    4. General Plant;
    5. Conservation Improvement Program; and
    6. Cost Recovery Riders.

Retail Non-firm and Other Industrial and Sales for Resale (Off-System) are discussed below. Additional detail for all revenue credits is shown on Exhibit ___ (Turner) Direct Schedule 2.

1. <u>Retail Non-firm and Other Industrial</u>

Q. What types of sales are included in the revenue credits for retail non-firm and other industrial power sales?

A. The total revenue credits on lines 1 and 2 of Exhibit ___ (Turner), Direct Schedule 2, Page 1 include revenues from interruptible sales to Minnesota Power's Residential and Commercial/Industrial Dual Fuel customers and LP IPS, RFPS, Economy sales, and

RFPS Service Fees for customers who own generation that is capable of serving part of their electric needs.

Q. Why are the Large Power products treated as revenue credits rather than Large Power revenue?

A. The Large Power Intersystem Sales products are separate from the Large Power customer class revenue because these revenues are not associated with providing service under the Large Power Service Schedule or any other retail rate schedule. The Economy and RFPS customers have their own generation, which they use to serve a portion of their load. Minnesota Power accredits this generation with the Midcontinent Independent System Operator ("MISO") under the requirements of MISO's Module E Resource Adequacy Program. This is similar to Minnesota Power's own generation accreditation with MISO and enables Minnesota Power to include the generation to meet system capacity reserve requirements even when it is not operating. This allows the customers to avoid buying standby service from Minnesota Power to cover generating unit outages, and it also allows Minnesota Power to use the customer generating capability to cover general system load when the large industrial customer's load is reduced. Customers with their own generation can also buy Economy/Non-firm energy from Minnesota Power in lieu of operating their own generation when it is cost-effective to do so (i.e., when the Economy energy price is lower than the customer's generation operating cost).

Q. Please describe LP IPS, Economy, non-Firm, and RFPS.

A. LP IPS is an interruptible energy product that is priced at Minnesota Power's incremental cost plus $10 per megawatt-hour ("MWh"). Large Power customers may utilize IPS for a small portion of their load (currently less than 10 percent of the customer's total load) that exceeds the firm service requirement. Because LP IPS is a non-firm incremental-cost based energy, it has historically been excluded from the Large Power customer class in the CCOSS. Similarly, customers with generation who have entered into Power Purchase Agreements with Minnesota Power are able to buy economy Energy/Non-Firm energy, which is priced at Minnesota Power's incremental cost plus an energy surcharge. Customers may purchase Economy/Non-Firm energy up to the available unused capacity of the units less reserves. If the units are unavailable, the customer may purchase RFPS, which is priced at the greater of 120 percent of Minnesota Power's incremental cost or $30/MWh.

2. Sales for Resale (Off-System)

Q. What are Minnesota Power's projected revenues from off-system wholesale power sales (non-requirements capacity and energy sales revenue) in the Unadjusted Test Year?

A. Budgeted capacity and energy revenues from sales to various counterparties and the wholesale market are shown on Exhibit ___ (Turner) Direct Schedule 2, page 2 and summarized on page 1, line 3. The capacity revenue comes from off-system sales to Minnkota, Oconto, Basin, NextEra, MISO, and Other. The energy revenue comes from a combination of specifically-identified bilateral sales and sales to the MISO market, including sales to AEP Energy Partners, Basin, Minnkota Power Liquidation, Market Sales, NextEra, Oconto, and Non-Minnesota Power Station Service. As a result of the Company's resolution of its 2019 rate case in Docket No. E015/M-20-429, any margins associated with these sales are accounted for through a credit in the annual Petition for Approval of the Annual Forecast of Automatic Adjustment Charges submitted on May 3 and have no direct impact on base rates in the test year.[5] Additional information regarding the base cost of fuel is provided in the Direct Testimony of Company witness Leah N. Peterson.

V. RATE CASE ADJUSTMENTS

Q. Please provide a summary of all rate case adjustments applied to the Unadjusted Test Year in this proceeding.

A. All rate case adjustments applying to rate base and operating income are included in Exhibit ___ (Turner) Direct Schedule 3. Each adjustment is identified by name,

[5] *In the Matter of Minn. Power's Petition for Approval of the Annual Forecast of Automatic Adjustment Charges for the period of January 2022 through December 2022*, Docket No. E015/AA-21-312, ANNUAL FILING (May 3, 2021).

categorized by whether it applies to the Interim Test Year and/or the Adjusted Test Year, and given an adjustment type. The adjustment type indicates whether the adjustment is required by prior Commission Order, is Customary or Voluntary based on the nature of the item, or Requested in this rate case specifically. Each adjustment is discussed in detail below. The Total Company amounts for each rate base adjustment are shown on Volume 1 Direct Schedule B-4 (IR) for the Interim Test Year and on Volume 3 Direct Schedule B-6 for the Adjusted Test Year. The Total Company amounts for each operating income adjustment are shown on Volume 1 Direct Schedule B-8 (IR) for Interim Test Year and on Volume 3 Direct Schedule C-10 for the Adjusted Test Year.

Q. Do any of the adjustments get handled differently in the Interim Test Year than they do in the Adjusted Test Year?

A. Yes, as indicated in Exhibit ___ (Turner) Direct Schedule 3, while most adjustments are made in both the Interim Test Year and the Adjusted Test Year, there are a few adjustments that are made in one and not the other.

Q. Are there any other differences in allocations for the Interim Test Year and the Adjusted Test Year?

A. As Company witness Mr. Shimmin explains in his Direct Testimony, the Company's Adjusted Test Year CCOSS includes proposed new allocation methodologies for Production demand-related costs and Transmission costs. However, consistent with prior rate cases, the Company's Interim Test Year CCOSS uses previously-approved allocation methodologies.

Additionally, the Company uses a different ROE in the Interim Test Year than in the Adjusted Test Year. The Commission authorized Minnesota Power to earn a 9.25 percent ROE in the 2016 Rate Case. Under Minnesota Statute §216B.16, subd. 3, unless the Commission finds that exigent circumstances exist, the utility shall include in Interim Rates a rate of ROE equal to that authorized by the Commission in the utility's most recent rate proceeding.

The Company is requesting Commission approval of an ROE of 10.25 percent in this proceeding, as supported by the Direct Testimony of Company witness Ann E. Bulkley. Because the requested ROE is higher than that authorized in Minnesota Power's most recent rate case proceeding, the Company uses the previously authorized, lower ROE of 9.25 percent in the Interim Test Year and the requested ROE of 10.25 percent in the Adjusted Test Year.

The Company's cost of capital is included on Volume 1, Schedule C-6 (IR) for the Interim Test Year and Volume 3, Direct Schedule D-1 for the Adjusted Test Year.

A. Rate Base Adjustments

1. Asset Retirement Obligation ("ARO")

Q. Please provide an explanation of the ARO adjustment.

A. In Minnesota Power's 2008 rate case (Docket No. E015/GR-08-415), the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision and consistent with handling in subsequent Company rate cases, this adjustment removes ARO related to the decommissioning of certain long-lived assets from rate base. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-1.

2. Cost to Retire

Q. Please provide an explanation of the Cost to Retire adjustment.

A. Related to the ARO adjustment above, in Minnesota Power's 2008 rate case (Docket No. E015/GR-08-415), the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision and consistent with handling in subsequent Company rate cases, this adjustment also reflects incorporation of decommissioning treatment instead of ARO. The cost to retire in accumulated depreciation on non-legal obligations is moved to a regulated liability under ARO. This adjustment puts it back into accumulated depreciation in rate base to reflect decommissioning treatment. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-2.

3. Decommissioning

Q. Please provide an explanation of the Decommissioning adjustment.

A. Related to the ARO and Cost to Retire adjustments above, in Minnesota Power's 2008 rate case (Docket No. E015/GR-08-415), the Commission rejected Minnesota Power's proposed use of the ARO method for ratemaking purposes. In accordance with the Commission's decision and consistent with handling in subsequent Company rate cases, this adjustment reflects incorporation of decommissioning treatment instead of ARO by including decommissioning accumulated depreciation in rate base. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-3.

4. Boswell 1 and 2 ("BEC 1 and 2") Regulated Asset

Q. Please provide an explanation of the Boswell 1 and 2 Regulated Asset adjustment.

A. In Minnesota Power's 2009 rate case (Docket No. E015/GR-09-1151) and in Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544), the Commission approved an end of life of 2022 for BEC 1 and 2. When Minnesota Power retired BEC 1 and 2 in December 2018 (earlier than required), a regulated asset was set up to reflect this continued cost recovery, with amortization through 2022. Minnesota Power is proposing the final year of amortization in 2022 be amortized over three years in the rate case test year to avoid over-collection in future rates. Three years is the amount of time until the Company plans to file its next retail rate case and matches the amortization period for Credit Card Fees, Service Center Sales, and Rate Case Expense adjustments, as described in Sections V.B.8, V.B.14, and V.B.24 of my testimony. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-4.

5. Boswell 3 Environmental Project

Q. Please provide an explanation of the Boswell 3 Environmental Project adjustment.

A. In Minnesota Power's 2009 rate case, the Commission approved a settlement which provided that Minnesota Power may recover $223 million of Total Company costs associated with the Boswell 3 ("BEC 3") environmental retrofit for regulatory purposes. Total BEC 3 environmental retrofit project capital additions were $238.2 million Total Company ($209.5 million MN Jurisdictional), requiring this adjustment reducing rate base. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-5.

6. Electric Vehicle Program ("EV Program")

Q. Please provide an explanation of the EV Program adjustment.

A. The Commission Order in Docket No. E015/M-20-638 stated, "Minnesota Power is welcome to request deferred accounting for its EV program costs; if the Company does so the Commission will consider the request on its merits at the appropriate time." The Company submitted its proposal in Docket No. E015/M-21-349 and is awaiting a Commission decision at the time this testimony is being completed. Therefore, the deferred program expenses recorded in Other Deferred Debits account are removed from rate base. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-6.

7. Electric Vehicle Service Equipment Project ("EVSE Project")

Q. Please provide an explanation of the EVSE Project adjustment.

A. In Docket No. E015/M-21-257, the Company requested deferred accounting of the its proposed EVSE Project costs and expenses for consideration in a subsequent rate case. The Commission approved the request for deferred accounting in its October 22, 2021 order. The capital costs related to the EVSE Project chargers and its corresponding line extensions are removed from plant in service, accumulated depreciation, and ADIT. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-7.

8. Pro Rata ADIT

Q. Please provide an explanation of the Pro Rata ADIT adjustment.

A. As Company witness Mr. Armbruster describes in his Direct Testimony, an IRS normalization requirement governs utilities that use forecasted test years for determination of rates, which requires calculation of average ADIT using a pro rata method. In the Company's 2016 Rate Case, the application of this normalization requirement was clarified as applying to Interim Rates but not to General Rates. Minnesota Power intends to adopt this methodology for recurring rate case proceedings — including this one. Thus, the pro rata ADIT methodology is reflected in the Interim Rate calculations but not in the General Rate calculations. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-8.

9. Aircraft Hangar

Q. Please provide an explanation of the Aircraft Hangar adjustment.

A. As Company witness Mr. Rostollan explains in his Direct Testimony, Minnesota Power has decided to forego recovery of any costs associated with the corporate aircraft and hangar in this rate case. The corporate aircraft that was previously owned by Minnesota Power was retired, and the new corporate aircraft is owned by ALLETE Enterprises as a non-regulated asset. The aircraft hangar is the only asset related to the aircraft still included in the Company's regulated plant balance and, thus, is adjusted out of the test year. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-9.

10. Continuing Cost Recovery Riders

Q. Please provide an explanation of the Continuing Cost Recovery Riders adjustment.

A. As Company witness Mr. Shimmin explains in his Direct Testimony, several projects in the unadjusted test year budget will remain in cost recovery riders and thus are adjusted out of the test year. Additional detail for these riders is included in the Direct Testimony of Mr. Shimmin and in Section VI of my testimony. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-10.

11. <u>DC Line Addition</u>

Q. Please provide an explanation of the DC Line Addition adjustment.

A. After the test year budget was initially completed, the Company determined an increase to Materials and Supplies was warranted due to a Major Supply Agreement in place with Meyer Utility Structures, LLC. This inventory was not included in the test year budget initially, but the balance is expected to continue for the foreseeable future; therefore, Materials and Supplies has been adjusted to include this amount. Details of this adjustment are provided in Volume 4 Workpaper ADJ-RB-11.

12. <u>Prepaid Other Post Employment Benefit ("OPEB") Asset</u>

Q. Please provide an explanation of the Prepaid OPEB Asset adjustment.

A. As Company witness Patrick L. Cutshall explains in his Direct Testimony, Minnesota Power is proposing to include the OPEB accumulated contributions in excess of net periodic benefit cost (or prepaid OPEB asset) in rate base. Minnesota Power's estimated test year prepaid OPEB asset is included in the Unadjusted Test Year CCOSS, represented as a 13-month average amount. Because the Company's prepaid OPEB asset was not previously included in rate base, the adjustment to remove the asset and associated ADIT is reflected in the Interim Rate calculations but not in the General Rate calculations. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-12.

13. <u>Prepaid Pension Asset</u>

Q. Please provide an explanation of the Prepaid Pension Asset adjustment.

A. As Company witness Mr. Cutshall explains in his Direct Testimony, Minnesota Power is proposing to include the pension plan accumulated contributions in excess of net periodic benefit cost (or prepaid pension asset) in rate base. Minnesota Power's estimated test year prepaid pension asset is included in the Unadjusted Test Year CCOSS, represented as a 13-month average amount. Because the Company's prepaid pension asset was not previously included in rate base, the adjustment to remove the asset and associated ADIT is reflected in the Interim Rate calculations but not in the

General Rate calculations. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-13.

14. Cash Working Capital

Q. Please provide an explanation of the Cash Working Capital adjustment.

A. Cash Working Capital is adjusted to reflect the impact of the various Operating Income adjustments, including those required by Commission policies for advertising expense, economic development, charitable contributions, and organizational dues, and other expense adjustments. In addition, state and federal income taxes in Cash Working Capital reflect interest synchronization and the tax impact of the revenue deficiency. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-14.

15. Changes in Allocations due to Adjustments

Q. Please provide an explanation of the Change in Allocations due to Adjustments adjustment.

A. When bridging from the unadjusted test year CCOSS to the adjusted test year CCOSS, a difference in allocation factors used between the two causes minor rate base component amount variances that need to be accounted for. Details of this adjustment are included in Volume 4 Workpaper ADJ-RB-15.

B. Operating Income Adjustments

1. Advertising Expense

Q. Please provide an explanation of the Advertising Expense adjustment.

A. In compliance with Minn. Stat. § 216B.16, subd. 8 and the Commission's June 14, 1982 Statement of Policy on Advertising, and to be consistent with the treatment allowed in the Company's 2016 Rate Case, certain advertising expenses are adjusted out of the test year. Recovery is allowed only for advertising designed to: (1) encourage energy conservation; (2) promote safety; (3) inform and educate consumers on the utility's financial services; and (4) disseminate information on a utility's corporate affairs to its owners.

In previous rate cases, the Company analyzed the most recent completed fiscal year, identified the adjustments, and applied the adjustments to the test year. The COVID-19 pandemic had an impact on the way Minnesota Power conducted its business in regards to advertising. In 2020, the Company modified its advertising campaign to respond to the pandemic. For example, advertising associated with school programs and sporting events was all rescinded. This resulted in the fiscal year 2020 not being representative of the normal level of business.

To determine the adjustment for test year 2022, the Company used the detailed analysis of 2018 advertising expenses performed for the initial filing of Minnesota Power's rate case in Docket No. E015/GR-19-442, which was the basis for its proposed adjustment to the 2020 test year in that proceeding. The 2018 analysis was revised to include advertising expenses identified in the Company's response to OAG-IR-1146 (Docket No. E015/GR-19-442). The ratios developed for 2018 were applied to the 2020 advertising expenses to determine the adjustment amount. The Company believes that 2018 represents a typical year and provides a reasonable basis for calculating the 2022 test year adjustment. Details of this adjustment are included in Volume 3 Direct Schedule G-1 and Volume 4 Workpaper ADJ-IS-1.

2. <u>Charitable Contributions</u>

Q. Please provide an explanation of the Charitable Contributions adjustment.

A. In compliance with Minn. Stat. § 216B.16, subd. 9, the Commission's June 14, 1982 Statement of Policy on Charitable Contributions, and to be consistent with the treatment allowed in the Company's 2016 Rate Case, 50 percent of qualifying contributions have been adjusted out of the test year. The Commission's Policy Statement requires that a qualifying charitable contribution: (1) serve the utility's Minnesota service area; (2) be nondiscriminatory in the selection of recipients; and (3) not promote a political or special interest group. A detailed listing of qualifying 2020 charitable contributions is provided in Volume 4 Workpaper ADJ-IS-2.

Based on the Commission's March 12, 2018 Order in Minnesota Power's 2016 Rate Case, which allowed rate recovery based on 50 percent of the Company's actual charitable giving for the previous three years and disallowed recovery of administrative costs, Minnesota Power has excluded administrative costs and calculated its charitable contributions based on 50 percent of average actual expense for the three years 2018-2020. Details regarding the excluded administrative expense and three-year average of charitable contributions are provided in Volume 3 Direct Schedule G-2.

Minnesota Power reports its donations to the Minnesota Power Foundation ("MP Foundation") in account 426.1 on FERC Form 1 for each respective prior year 2018-2020. Each yearly amount includes Minnesota Power's lump sum contributions to the MP Foundation plus some smaller direct donations by Minnesota Power. The account also includes Minnesota Power sponsorships, donation expenses, and donations outside of Minnesota Power's territory. For this reason, donation amounts in FERC Form 1 will not equal the exact amounts of MP Foundation donations. The detailed listing of donations included in Volume 4 Workpaper ADJ-IS-2 is provided as an example of the types of organizations, amounts, and service territory locations to which the MP Foundation typically makes contributions and shows Minnesota Power's compliance with the Commission's Statement of Policy on Charitable Contributions.

3. Economic Development

Q. Please provide an explanation of the Economic Development adjustment.

A. 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 adjusted out 50 percent of its Economic Development and Community Relations costs in the Interim Test Year. However, the Company is requesting recovery of 100 percent of its Economic Development and Community Relations in the Adjusted Test Year. Therefore, the adjustment to remove 50 percent of the costs is reflected in the Interim Rate calculations but not in the General Rate calculations. Company witness Frank L. Frederickson discusses the benefits of the Company's Economic Development and

Community Relations efforts, which are especially significant to host communities as the energy system continues its transformation. Volume 3 Direct Schedule G-5 provides details regarding the Company's Economic Development and Community Relations costs. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-3.

4. Organizational Dues

Q. Please provide an explanation of the Organizational Dues adjustment.

A. In compliance with the Commission's Statement of Policy on Organizational Dues issued June 14, 1982 and consistent with the treatment allowed in the Company's 2016 Rate Case, certain organizations' dues related to lobbying are adjusted out of the test year. A detailed listing of organizational dues and the calculation of the excluded amount, which consists of lobbying expenses that were billed along with other organizational dues, is provided in Volume 4 Workpaper ADJ-IS-4.

5. Employee Expenses

Q. Please provide an explanation of the Employee Expenses adjustment.

A. Similar to the description provided for the Advertising Expense adjustment above, the COVID-19 pandemic had an impact on the way Minnesota Power conducted its business in regards to Employee Expenses. This adjustment removes certain Board of Directors and employee expenses from the test year. The methodology for determining items to be excluded and the calculation of the adjustment is provided in the Direct Testimony of Company witness Mr. Rostollan and shown in detail on Volume 3 Direct Schedule H-1. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-5.

Consistent with the Commission's decision in the Company's 2016 Rate Case, Minnesota Power has excluded all legislative lobbying expenses from its test year. Most lobbying expenses are recorded in Account 426.4, which is not a part of regulated expense. However, as described in the Direct Testimony of Company witness Mr. Rostollan, the Company's analysis determined that some indirectly-related lobbying expenses were included in other employee expense accounts. Therefore, an additional adjustment was made to exclude those lobbying expenses from the test year. This is included in the Employee Expenses adjustment.

6. Incentive Compensation

Q. Please provide an explanation of the Incentive Compensation adjustment.

A. Based on prior Commission practice and Orders in Minnesota Power's previous rate cases and other utility rate cases, Minnesota Power has made adjustments to exclude a portion of the budgeted expense for its Annual Incentive Plan ("AIP") and all of the budgeted expense for its Long-Term Incentive Plan ("LTIP"), Supplemental Executive Retirement Plan ("SERP"), and Executive Deferral Plan. The incentive compensation plans are described in the Direct Testimony of Company witness Laura E. Krollman. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-6.

Q. Please describe the adjustment for the Company's AIP.

A. Consistent with the Commission-ordered treatment for incentive compensation in the Company's 2009 and 2016 rate cases, Minnesota Power has adjusted out the budgeted amount of compensation expense for the AIP that exceeds 20 percent of base pay for Interim Rates and for General Rates.

Q. Please describe the adjustment for the Company's LTIP.

A. Consistent with prior Commission practice and orders, Minnesota Power has adjusted out the entire budgeted amount of regulated expense associated with its LTIP for Interim Rates and for General Rates.

Q. Please describe the adjustment for the Company's SERP.

A. Consistent with prior Commission practice and orders, Minnesota Power has adjusted out the entire budgeted amount of regulated expense associated with its SERP retirement and annual restoration plans for Interim Rates and for General Rates.

Q. Please describe the adjustment for the Company's Executive Deferral Plan.

A. Consistent with prior Commission practice and orders, Minnesota Power has adjusted out the entire budgeted amount of regulated expense associated with its Executive Deferral Plan for Interim Rates and for General Rates.

7. Investor Relations

Q. Please provide an explanation of the Investor Relations adjustment.

A. As Company witness Mr. Rostollan explains in his Direct Testimony, consistent with recent Commission decisions, Minnesota Power has adjusted out 50 percent of investor relations expense from the test year. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-7.

8. Credit Card Fees

Q. Please provide an explanation of the Credit Card Fees adjustment.

A. In the Company's 2016 Rate Case, the Commission approved the Company's proposed removal of the per-transaction fee each customer incurred when making bill payments by credit or debit card and allowed the Company to instead include the costs of accepting card payments in Minnesota Power's overall operating expense. The Company's estimated annual increase in costs incurred for credit card processing fees was $350,000 (Total Company and MN Jurisdictional).

Recognizing the uncertainty in the amount of actual credit or debit card processing fees, since Minnesota Power had never before offered customers the option to pay their bills via credit card without incurring a fee, the Commission required the Company to track over- or under-collections for true-up in a future rate case.

After October 2018, when Minnesota Power implemented the no-fee credit or debit card payment option for retail customers following Commission approval, Minnesota Power began tracking the difference between the amount collected in rates and the actual expenses paid by Minnesota Power. The net difference is currently an over-recovery. The projected balance of the over-recovery on the proposed interim rate effective date of January 1, 2022, is $167,448.

Minnesota Power proposes that the accumulated over-recovery for credit or debit card processing fees be returned to customers in this rate case as a negative expense amortized over three years. Three years is the amount of time until the Company plans to file its next retail rate case and matches the amortization period for the BEC 1 and 2 Regulated Asset, Service Center Sales, and Rate Case Expense adjustments, as described in Sections V.B.11, V.B.14, and V.B.24 of my testimony. Details of this adjustment are included on Volume 4 Workpaper ADJ-IS-8.

9. ARO

Q. Please provide an explanation of the ARO adjustment.

A. In accordance with the Commission's May 4, 2009 Order in Minnesota Power's 2008 rate case, as described in Section V.A.1 of my testimony, Minnesota Power has adjusted depreciation and amortization expense and accretion expense to remove ARO. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-9.

10. Decommissioning

Q. Please provide an explanation of the Decommissioning adjustment.

A. Related to the ARO adjustment above and in accordance with the Commission's May 4, 2009 Order in Minnesota Power's 2008 rate case, as described in Section V.A.3 of my testimony, Minnesota Power has adjusted depreciation expense to include decommissioning. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-10.

11. Boswell 1 and 2 Regulated Asset

Q. Please provide an explanation of the BEC 1 and 2 Regulated Asset adjustment.

A. Along with the rate base adjustments described in Section V.A.4 of my testimony, there is an associated adjustment to amortization expense. This adjustment is proposed to be amortized over three years. Three years is the amount of time until the Company plans to file its next retail rate case and matches the amortization period for Credit Card Fees, Service Center Sales, and Rate Case Expense adjustments as described in Sections V.B.8, V.B.14, and V.B.24 of my testimony. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-11.

12. Boswell 3 Environmental Project

Q. Please provide an explanation of the BEC 3 Environmental Project adjustment.

A. Along with the rate base adjustments described in Section V.A.5 of my testimony, there is an associated adjustment to reduce depreciation expense. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-12.

13. EVSE Project

Q. Please provide an explanation of the EVSE Project adjustment.

A. Along with the rate base adjustments described in Section V.A.7 of my testimony, this is an associated adjustment to reduce depreciation expense. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-13.

14. Service Center Sales

Q. Please provide an explanation of the Service Center Sales adjustment.

A. This adjustment combines adjustments for the sales of three service centers, land, and buildings near Boswell Energy Center, as well as the transfer of a loader to non-regulated operations. On June 1, 2017, Minnesota Power filed a request for approval of four transactions, including the sale of its Aurora Service Center to Lakehead Constructors, Inc., the sale of its Chisholm Service Center to the United Way of Northeastern Minnesota, Inc., and the sale of land and buildings near the Boswell Energy Center to Airmark, Inc. d/b/a Nelson, Wood Shims. In its February 8, 2018 Order Approving Purchases and Sales with Conditions,[6] the Commission approved the

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[6] *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Sale of the Aurora Serv. Center to Lakehead Constructors, Inc.*, Docket No. E-015/PA-17-457, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018); *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Sale of the Chisolm Serv. Center to United Way of N. Minn., Inc.* Docket No. E-015/PA-17-

transactions and required that Minnesota Power use deferred accounting to create regulatory liabilities for these transactions as recommended by the Minnesota Department of Commerce – Division of Energy Resources ("Department"). On November 23, 2020, Minnesota Power filed a request for approval of the sale of its Crosby Service Center to Spalj Real Estate, LLC. In its January 25, 2021 Order,[7] the Commission approved the sale of the Crosby Service Center and required that Minnesota Power use deferred accounting to create a regulatory liability for the transaction as recommended by the Department. In the Commission's April 6, 2020 Order approving Minnesota Power's 2019 Remaining Life Depreciation Petition,[8] Minnesota Power was ordered to establish a regulatory liability for the loader transfer from Laskin Energy Center to non-regulated Rapids Energy Center.

The Commission also required the Company to submit a compliance filing within 60 days of closing each transaction that included a detailed explanation and schedules for the regulatory liabilities established in connection to these four transactions and appropriate journal entries. The Aurora Service Center sale closed on December 27, 2017, and Minnesota Power submitted its compliance filing on February 26, 2018. The regulatory liability through December 2021 is $0.4 million Total Company. The Chisholm Service Center sale closed on January 17, 2018, and Minnesota Power submitted its compliance filing on March 9, 2018. The regulatory liability through December 2021 is $0.5 million Total Company. The sale of land and buildings near the Boswell Energy Center closed on November 26, 2019, and Minnesota Power submitted its compliance filing on January 24, 2020. The regulatory liability through

459, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018); *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Sale of Land and Bldg. near the Boswell Energy Center to Airmark, Inc. d/b/a Nelson Wood Shims*, Docket No. E-015/PA-17-460, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018); *In the Matter of the Petition of Minn. Power for Approval of a Purchase Agreement for the Purchase of the Long Prairie Serv. Center from the State of Minn. Dept. of Military Affairs,* Docket No. E-015/PA-17-461, ORDER APPROVING PURCHASES AND SALES WITH CONDITIONS (Feb. 8, 2018).

[7] *In the Matter of Minn. Power's Approval of a Purchase Agreement with Spalj Real Estate, LLC*, Docket No. E-015/PA-20-839, ORDER (Jan. 25, 2021).

[8] *In the Matter of Minn. Power's 2019 Remaining Life Depreciation Petition*, Docket No. E-015/D-19-534, ORDER APPROVING REMAINING LIVES AND SALVAGE RATES, REQUIRING REGULATORY LIABILITY, AND REQUIRING COMPLIANCE FILING at 7 (Apr. 6, 2020).

December 2021 is $0.1 million Total Company. The Crosby Service Center sale closed on March 8, 2021, and Minnesota Power submitted its compliance filing on April 26, 2021. The regulatory liability through December 2021 is $0.3 million Total Company. In the Commission's April 6, 2020 Order Approving Minnesota Power's 2019 Remaining Life Depreciation Petition, Minnesota Power was also ordered to submit a compliance filing within ten days of that order showing the Company's finalized calculation of any journal entries for the relevant regulatory accounts. Minnesota Power submitted its compliance filing on April 16, 2020 and sent a supplemental compliance filing on April 21, 2020 pursuant to an informal information request from the Department. The regulatory liability through December 2021 is $0.1 million Total Company.

Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-14.

Q. What treatment does the Company propose for the regulatory liability?

A. Minnesota Power proposes to amortize the regulatory liability balances over three years beginning January 1, 2022 and return to customers as a credit to Other Operating Revenue. Three years is the amount of time until the Company plans to file its next retail rate case and matches the amortization period for Credit Card Fees, BEC 1 and 2 Regulated Asset amortization expense, and Rate Case Expense adjustments, as described in Sections V.B.8, V. B.11, and V.B.24 of my testimony. The total combined regulatory liability balance for sales of service centers and land and buildings near Boswell Energy Center and transfer of a loader out of regulated is $1.4 million Total Company.

15. <u>Conservation Expense</u>

Q. Please provide an explanation of the Conservation Expense adjustment.

A. For accounting purposes, Minnesota Power records conservation expense (Account 908) each month as its conservation expenditures and charges that are accumulated in the Conservation Cost Tracker Account ("CIP Tracker Account") are recovered from customers. Cost recovery is achieved through a combination of the Conservation Cost

Recovery Charge ("CCRC") in base rates and the Conservation Program Adjustment ("CPA"). The CCRC and CPA are discussed further in Sections V.B.22 and V.B.21 of my testimony. The CPA is modified each year as part of Minnesota Power's CIP Consolidated Filing. The modified CPA is based on projected CIP spending levels, the amount recovered through base rates, carrying charges, financial incentives, and the CIP Tracker Account balance at the end of the prior year. Minnesota Power's 2022 budgeted conservation expense of $11.9 million (Total Company and MN Jurisdictional) in Account 908 and thus includes recovery of conservation expenditures that are not limited to what Minnesota Power expects to spend on conservation programs during the test year.

Consistent with how conservation expenses were handled in Minnesota Power's 2008, 2009, and 2016 rate cases, it is appropriate to include the projected conservation expenditures for CIP programs in the test year based on approved annual CIP budgets filed with and approved by the Department. Test year conservation expense has been adjusted to remove the $11.9 million in Minnesota Power's 2022 budget for Account 908 and instead include projected 2022 expenditures of $10.7 million based on Minnesota Power's 2021-2023 CIP Triennial plan as approved by the Department of Commerce on November 24, 2020 in Docket No. E015/CIP-20-476. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-15. For Interim and General Rates, an updated CCRC was calculated based on the 2022 CIP Budget and test year retail energy sales excluding CIP-exempt customers. This calculation is shown in Volume 3, Direct Schedule I-1.

16. <u>Aircraft Hangar</u>

Q. Please provide an explanation of the Aircraft Hangar adjustment.

A. As described in Section V.A.9 of my testimony, Minnesota Power is not seeking recovery of any costs associated with the corporate aircraft. No corporate aircraft expense was included in the test year regulated administrative and general expense, so no adjustment is required. However, depreciation expense related to the aircraft hangar is included in the test year and is adjusted out by means of this adjustment. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-16.

17. <u>Customer Affordability of Residential Electricity ("CARE")</u>

Q. Please provide an explanation of the CARE adjustment.

A. Minnesota Power's Rider for Customer Affordability of Residential Electricity ("CARE Rider") provides discounted rates to qualified low-income Residential customers and is funded by an Affordability Surcharge assessed to other customers. The CARE Rider discounts and surcharge collections are accumulated in a tracker and adjusted as necessary between rate cases. Therefore, the Residential customer class discount and surcharge revenue from all customer classes are adjusted out of sales of electricity for CCOSS purposes. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-17.

18. <u>CIP Incentive</u>

Q. Please provide an explanation of the CIP Incentive adjustment.

A. In Minnesota Power's annual CIP Consolidated Filings, the Commission has permitted Minnesota Power to collect financial incentives for its CIP achievements and also to collect a carrying charge on its CIP tracker account balance. Because these revenues are intended to provide an incentive to the Company and to provide a return on outstanding tracker account balances, they are adjusted out of Other Operating Revenue for ratemaking purposes. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-18.

19. <u>CIP Carrying Charge</u>

Q. Please provide an explanation of the CIP Carrying Charge adjustment.

A. In Minnesota Power's annual CIP Consolidated Filings, the Commission has permitted Minnesota Power to collect financial incentives for its CIP achievements and also collect a carrying charge on its CIP tracker account balance. Because these revenues are intended to provide an incentive to the Company and to provide a return on outstanding tracker account balances, they are adjusted out of Other Operating Revenue for ratemaking purposes. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-19.

20. CPA Incentive

Q. Please provide an explanation of the CPA Incentive adjustment.

A. The CPA Incentive revenue is the portion of revenue for the CIP incentive that is included in the CPA on customer bills. This is recovered over two years and represents the average of 2021 and 2022 CIP Incentive revenue. CPA Incentive revenue is adjusted out of Operating Revenue. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-20.

21. CPA

Q. Please provide an explanation of the CPA adjustment.

A. This is a second piece of the CPA Incentive adjustment described above. This consists of the total revenue received from customers for the CPA within the CIP Rider. The Total CPA revenue is adjusted out of Operating Revenue because the CIP Rider will continue on customer bills outside of base rates. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-21.

22. CCRC

Q. Please provide an explanation of the CCRC adjustment.

A. The CCRC credit amount related to the CIP-exempt Large Light and Power customers included in the test year budget is adjusted out of Operating Revenue because the CCRC credit amount is contained in the CIP Tracker and corresponding rates are adjusted outside of base rates. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-22.

23. Continuing Cost Recovery Riders

Q. Please provide an explanation of the Continuing Cost Recovery Riders adjustment.

A. Along with the rate base adjustment described in Section V.A.10 of my testimony, there are associated adjustments to operating expense, depreciation expense, and taxes. This adjustment removes: Solar O&M expense and Great Northern Transmission Line O&M expense, Multi-Value Project transmission credits, MISO Regional Expansion Criteria and Benefits expense from Transmission expense, Depreciation Expense for projects with costs recovered in riders, MN Solar Production Tax expense, and Property Tax expense with costs recovered in riders. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-23.

24. Rate Case Expense

Q. Please provide an explanation of the Rate Case Expense adjustment.

A. The Company included in rate case expense projections the directly-assignable costs associated with preparing and filing the rate case, including outside legal fees, expert witnesses and consultants, state agency fees, and administrative costs. Rate case expense does not include any Company labor and overheads, consistent with previous filings, and a portion of the total cost is allocated to non-regulated activities, consistent with the methodology approved by the Commission in Minnesota Power's previous rate cases. A summary of the projected rate case expenses compared to actual expenses for Minnesota Power's 2016 Rate Case, and details of this adjustment are included in Volume 4 Workpaper ADJ-IS-24.

Projected rate case expenses were based on examining actual expenditures in the Company's 2016 Rate Case and updated for current expectations. Projections for contract and professional services expenses were based on estimates of the fees for expert witnesses, consultants, and outside legal counsel who are anticipated to be used in this proceeding. Similarly, Commission regulatory assessments are projected based on actual assessments for the 2016 Rate Case. Additionally, "other costs" were projected, including employee-related expenses associated with the rate case and expenses such as printing/copying charges and preparation and mailing of notices to customers.

A portion of "Contract and Professional Services" costs includes amortized costs that were incurred in the development of the Company's 2019 rate case (Docket No. E015/GR-19-442), which was withdrawn. These costs are for outside legal and consultant services, which were incurred for work related to the 2019 rate case that was used in the development of this rate case.

Total projected rate case expenses have been amortized for a period of three years. Three years is the amount of time until the Company plans to file its next retail rate case and matches the amortization period for Credit Card Fees, BEC 1 and 2 Regulated Asset amortization expense, and Service Center Sales, as described in Sections V.B.8, V.B.11, and V.B.14 of my testimony.

25. Revenue Budget Corrections

Q. Please provide an explanation of the Revenue Budget Corrections adjustment.

A. When comparing unadjusted revenue in the test year to the revenue calculated in Volume 3 Direct Schedules E-1 and E-2, the Company calculated minor differences due to the build-up of revenue in the test year budget. These differences are accounted for as an adjustment to budgeted Operating Revenue to ensure the correct revenue amounts are used in the CCOSS. This allows present rate revenues to reconcile in the CCOSS and Volume 3 Direct Schedules E-1 and E-2. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-25.

26. Excess ADIT

Q. Please provide an explanation of the Excess ADIT adjustment.

A. In the Commission's December 5, 2018 Order in Docket No. E, G-999/CI-17-895, the Commission established methods for rate-regulated utilities to incorporate into rates the tax cost savings resulting from the Tax Cuts and Jobs Act. Minnesota Power's Rider for 2017 Federal Tax Cut Refund ("Tax Cut Refund Rider") returns to customers the protected Excess ADIT, amortized using Average Rate Assumption Method as early as Internal Revenue Service provisions allow, plus unprotected Excess ADIT, amortized over ten years. It was approved by the Commission in Docket No. E, G999/CI-17-895, with an effective date of January 1, 2019. The Excess ADIT refund factor is applied as a percent of customer bills.

Minnesota Power is proposing to include the Excess ADIT credit in base rates and cancel the Tax Cut Refund Rider effective with interim rates. The 2022 amortization amounts related to including the Excess ADIT in base rates are explained in Company witness Mr. Armbruster's testimony. This adjustment removes the Excess ADIT credit from total revenue. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-26.

27. <u>Demand Response ("DR") Product A Reassignment</u>

Q. Please provide an explanation of the DR Product A Reassignment adjustment.

A. In the Company's previous rate cases, DR Product A and curtailable credit 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. Additional detail for this adjustment is provided in the Direct Testimony of Company witness Ms. Peterson and is included in Volume 4 Workpaper ADJ-IS-27.

28. <u>LP Demand Response</u>

Q. Please provide an explanation of the LP Demand Response adjustment.

A. This adjustment accounts for a reflection of the full year of lower DR Product A and other LP Demand Response with the implementation of Product C. This adjustment is not reflected in the Interim Rate calculations but is reflected in the General Rate calculations. Additional detail for this adjustment is provided in the Direct Testimony of Company witness Ms. Peterson and is included in Volume 4 Workpaper ADJ-IS-28.

29. Boswell Inspection Costs

Q. Please provide an explanation of the Boswell Inspection Costs adjustment.

A. In Docket No. E999/AA-20-171, the Administrative Law Judge ("ALJ") suggested that the Company did not follow good utility practice surrounding inspections frequency on the high energy piping, specifically the hot reheat piping at Boswell Energy Center. BEC 3 has 180 linear feet of hot reheat piping to be inspected in 2022 that fall within the five-year Electric Power Research Institute recommended inspection guideline. The costs included in this adjustment are a result of this ALJ recommendation. Additional costs for subscribing to utility user groups in which the site did not previously participate are included in this adjustment as these are fee-based annual memberships. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-29.

30. Interest Synchronization

Q. Please provide an explanation of the Interest Synchronization adjustment.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt multiplied by the average rate base. This calculation must be updated whenever a change in rate base, weighted cost of debt, or operating income occurs. Minnesota Power will therefore recalculate the interest synchronization expense after the final adjustments to rate base, weighted cost of debt, and operating income are determined in this case. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-30.

31. Changes in Allocations due to Adjustments

Q. Please provide an explanation of the Changes in Allocations due to Adjustments adjustment.

A. When bridging from the unadjusted test year CCOSS to the adjusted test year CCOSS, a difference in allocation factors used between the two causes minor income statement component amount variances that need to be accounted for. Details of this adjustment are included in Volume 4 Workpaper ADJ-IS-31.

VI. COST RECOVERY RIDERS AND TRACKERS

A. Cost Recovery Riders

Q. Please explain how Minnesota Power's cost recovery riders are handled in this rate case.

A. As Company witness Mr. Shimmin describes in his Direct Testimony, Minnesota Power currently recovers the costs of several transmission and renewable resource projects through riders whose rates were determined in separate dockets based on individual project revenue requirement calculations. The proposed rate case treatment of rider projects is explained in Mr. Shimmin's testimony.

By way of summary, projects moving to base rates will be rolled in beginning January 1, 2022 and, as such, their revenue requirements will be included in the test year and excluded from rider recovery effective at the same time. For projects that will remain in the riders, cost recovery will continue through the applicable rider. Appropriate rate base and income statement adjustments have been made to exclude projects remaining in riders from rate base and their associated expenses from test year expenses, so no double-recovery of costs takes place. Revenue to be collected through the continuing riders has also been excluded from total revenues for cost-of-service purposes. This is discussed in more detail in Section V.B.23 of my testimony.

B. Conservation Improvement Program

Q. How has the Company historically treated CIP costs?

A. The Commission approved a deferred debit accounting mechanism and established a CIP Tracker Account in the Company's 1987 general rate case (Docket No. E015/GR-87-223). Conservation expenditures and costs are entered into the CIP Tracker Account. These charges are recovered through a combination of base rates and the CPA. Funds in the CIP Tracker Account are subject to a carrying charge utilizing the rate from Minnesota Power's multi-year credit facility. The Commission approves the rate of recovery of the CIP Tracker Account balances in the Company's annual CIP filings, the latest of which was filed on April 1, 2021 (Docket No. E015/M-21-199).

Q. What is the current and future status of the CIP Tracker Account?

A. The CIP Tracker Account balance was $380,310[9] as of December 31, 2020. It is anticipated that the CIP Tracker Account will continue to be used in a manner consistent with recent years in that the entry of CIP-related charges and cost recovery amounts will be made to this account and reported in annual CIP filings.

Q. Please describe the existing conservation recovery mechanism.

A. Minnesota Power's conservation costs are recovered through a combination of the per-kWh CCRC included in base rates and the CPA adder on customer bills. The current CCRC that was determined in Minnesota Power's 2016 Rate Case is $0.003299105 per kWh. In a Commission Order dated September 7, 2021 (Docket No. E015/M-21-199), the Commission approved Minnesota Power's revised CPA charge of $0.002015 per kWh, effective October 1, 2021, based on projected conservation spending levels, the amount recovered through base rates, carrying charges, financial incentives, and the CIP Tracker account balance at the end of the prior year.

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[9] *In the Matter of Minn. Power's 2020 Conservation Improvement Program Consolidated Filing*, Docket E015/M-21-199, REPORTING ON CIP TRACKER ACCT. ACTIVITY, FINANCIAL INCENTIVES REPORT, PROPOSED CPA FACTORS AND 2020 PROJECT EVALUATIONS at 5 (Apr. 1, 2021).

Q. What is the CIP expense level included in the test year?

A. The CIP expense level for the 2022 test year is $10,714,344. This expense level is based on approved 2022 CIP spending from Minnesota Power's 2021-2023 CIP Triennial filing (Docket No. E015/CIP-20-476).

The Company plans to continue utilizing the Conservation Tracker Account and CPA mechanism to correct for over- and under-collections through base rates. Pursuant to the Commission's decision in Docket No. E015/GR-94-001, no prior tracker balances are included in the test year for recovery in base rates.

Q. What is the proposed revised CCRC to be included in base rates?

A. Based on test year conservation expenses and energy sales subject to the CCRC, Minnesota Power proposes a revised CCRC of $0.00413317 per kWh. The calculation of the revised CCRC is shown in Volume 3 Direct Schedule I-1.

Q. Will the CCRC be applied to customers who are exempt from the CIP requirements?

A. No, it will not. Consistent with currently authorized treatment, the CCRC will not apply to several large customers who have been granted exemptions from participation in CIP, Economy energy, or customers taking service under the Company's Competitive Rate Schedules. In the 2008 rate case (Docket E015/GR-08-415), Minnesota Power revised the CCRC methodology so that it is not built into Large Power rates as they are CIP-exempt. The same methodology for Large Power customers continues to be followed here. For other customers with CIP exemptions, the CCRC amount is refunded to them because it is built into their base rates. The test year conservation expense is allocated to retail rate classes based on each class's MWh of energy subject to the CCRC.

C. <u>Tax Cut Refund Rider</u>

Q. What change does Minnesota Power propose to the Tax Cut Refund Rider in this rate case?

A. As described in Section V.B.26 of my testimony, Minnesota Power proposes to include the Excess ADIT credit in base rates and cancel the Tax Cut Refund Rider effective with interim rates.

VII. OTHER COMPLIANCE REQUIREMENTS

A. <u>Renewable Energy Credit ("REC") Purchases</u>

Q. What was the compliance requirement related to REC purchases?

A. In its December 18, 2007 Order Establishing Initial Protocols for Trading Renewable Energy Credits (Docket Nos. E999/CI-03-869 and E999/CI-04-1616), the Commission required utilities seeking recovery of prudent costs related to registration, annual fees, and transaction costs related to renewable energy credit purchases to file specific proposals for cost recovery.

Q. Is Minnesota Power proposing recovery of costs related to registration, annual fees, or transaction costs related to renewable energy credit purchases?

A. No. Minnesota Power has not included any REC purchases or related costs in the proposed 2022 test year.

B. <u>Thomson Hydro Investment Tax Credits ("ITCs")</u>

Q. What was the compliance requirement related to Thomson Hydro ITCs?

A. In its November 8, 2017 Order on Minnesota Power's 2017 Renewable Resources Rider ("RRR") Rate Factor Filing, the Commission required that the Company "return any amortized federal investment tax credits associated with Thomson Hydro to customers through future RRR filings until they can be included in base rates in a subsequent rate case."

Q. What is the status of Minnesota Power's ITCs related to Thomson Hydro?

A. The Company is not utilizing any new Thomson Hydro ITCs at this time and doesn't expect to do so until approximately 2023, as it has been in a federal net operating loss ("NOL") position or using a federal NOL carryforward in each year since 2010.

Although no new ITCs have been utilized, consistent with the discussion in the Company's 2016 Rate Case, ITCs earned prior to 2010 continue to be amortized and are reflected in the Company's CCOSS. Minnesota Power also earned a federal ITC for Thomson Hydro Dam in 2015 and claimed the ITC on its federal income tax return. However, due to NOL carryforwards, Minnesota Power was not able to utilize the ITC on its return, and the ITC became an ITC carryforward. To reflect that the ITC has not been utilized but has become a carryforward, the ITC is recorded as a carryforward tax asset — in this case — a deferred tax asset. As Company witness Mr. Armbruster describes in his Direct Testimony, Minnesota Power is following the normalization requirements, both by beginning the amortization period once the credit is used to reduce federal tax liability and by amortizing the credit over the remaining book life of the underlying asset.

C. <u>Department of Commerce Recommended Filing Requirements</u>

Q. What were the Department's recommended filing requirements for Minnesota Power's next rate case?

A. In Surrebuttal Testimony in the 2016 Rate Case,[10] DOC witness Nancy Campbell recommended that the Commission require Minnesota Power to provide the following in Minnesota Power's next rate case before the Commission determines that the Company's rate case petition is complete:

- All Minnesota Power financial witnesses will need to tie out their numbers to the overall revenue requirements witness;

[10] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Util. Serv. in Minn.*, Docket No. E015/GR-16-664, SURREBUTTAL TESTIMONY OF NANCY CAMPBELL at 70-71 and 81 (July 21, 2017).

- Minnesota Power may use their Responsibility Center[11] information and numbers, but Minnesota Power must also include all additional information and numbers (such as overheads, allocations, third-party costs and revenues) that ties out to the FERC accounts;
- All numbers should be provided on a Total Company basis, and Minnesota Jurisdictional basis, with reference and support for allocators used;
- Financial schedules should fully support the test year revenue requirement; for example, while transmission expenditures by 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;
- 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 Minnesota Jurisdictional); and
- All schedules in a rate case should breakout the rider recovery and rate case recovery.

Q. How did Minnesota Power address the Department's recommendations?

A. Although the Commission did not specifically order Minnesota Power to follow these recommendations, at the 2016 Rate Case evidentiary hearing, the Company agreed that it would follow them to the extent possible. In the planning and preparation of this rate case, Minnesota Power made all witnesses and other staff working on the rate case aware of these expectations and has made a good faith effort to follow them. The Company put in place a detailed review process with documentation to assure that the numbers in all financial witnesses' testimony and schedules tie to the overall revenue requirements witness. More detailed test year information has been provided by FERC accounts in the filing to enable comparisons with historical information. For capital projects, Plant in Service and retirement amounts have been provided, and extra care was taken to be precise and accurate with terminology and labeling. Additionally, more

[11] At the evidentiary hearing, Minnesota Power clarified that, while the Department referenced "reliability centers," this was intended to more correctly reference Company "Responsibility Centers."

detailed information for the test year and historical years has been provided for transmission revenues and expenses to make it easier to analyze and reconcile.

The Company has also attempted to provide consistent numbers for all years and to include Minnesota Jurisdictional numbers throughout the case wherever reasonable and practical, particularly in the financial witnesses' testimony. Where numbers are included in non-financial witness testimony to show historical trends for certain items, Minnesota Jurisdictional amounts are provided wherever possible. When it wasn't practical to provide both Total Company and Minnesota Jurisdictional numbers, clear designations are made on what is provided. And the Company is, of course, open to working with the parties if any questions should arise.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

			Interim Rates			General Rates		
Line No.		Calculation Note	COSS	Summary of Revenue	Difference	COSS	Summary of Revenue	Difference
			(1)	(2)	(3)	(4)	(5)	(6)
1	Present Rates Sales by Rate Class and Dual Fuel		$ 613,659,194	$ 613,659,226	$ 32	$ 615,949,394	$ 615,949,426	$ 32
2	Calculated Revenue Deficiency/Revenue Increase		$ 87,341,793	$ 87,323,708	$ (18,085)	$ 108,314,136	$ 108,314,041	$ (95)
3	Requested Rate Increase Percentage	line 2 / line 1	14.23%	14.23%		17.58%	17.58%	
4	Total Proposed Revenues	line 1 + line 2	$ 701,000,987	$ 700,982,934	$ (18,053)	$ 724,263,530	$ 724,263,467	$ (63)

(1) Volume 4, COS-1, Part 1, Page 1
(2) Volume 4, IR-1, Page 2
(4) Volume 3, Direct Schedule E-3, Part 1, Page 1
(5) Volume 3, Direct Schedule E-1, page 2

Note
a) All numbers shown are Minnesota Jurisdiction.
b) Minor differences shown in columns (3) and (6) are due to rounding in calculations.
c) Revenue Increase in Columns (2) and (5) includes Large Power (Other) revenues to be consistent with presentation

Line No.	Revenue Credit	Unadjusted Test Year 2022 Total Company (1)	Unadjusted Test Year 2022 Minnesota Jurisdiction (2)
1	Dual Fuel	$ 10,231,437	$ 10,231,437
2	LP Intersystem Sales	$ 38,067,674	$ 32,671,926
3	Sales for Resale (Off-System)	$ 115,185,926	$ 99,659,035
4	Other Operating Revenue		
5	Production	$ 1,990,996	$ 1,721,499
6	Transmission	$ 87,742,901	$ 71,968,071
7	Distribution	$ 1,220,915	$ 1,160,931
8	General Plant	$ 756,992	$ 672,901
9	Conservation Improvement Program	$ 1,750,087	$ 1,750,087
10	Solar Renewable Resources Rider	$ 2,029,674	$ 2,029,674
11	Transmission Cost Recovery Rider	$ 28,815,878	$ 28,815,878
12	Total Other Operating Revenue	$ 124,307,443	$ 108,119,041
13	Total Revenue Credits	$ 287,792,480	$ 250,681,439

(1) Volume 4, COS-2, Part 4b, column (1)
(2) Volume 4, COS-2, Part 4b, column (3)

PUBLIC DOCUMENT
NON-PUBLIC DATA EXCISED

Line No.	Sales for Resale (Off-System)	January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	Total 2022
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Capacity	[TRADE SECRET DATA BEGINS												
2	Aitkin Public Utilities	[redacted]												
3	Biwabik Public Utilities													
4	Buhl													
5	Ely													
6	Gilbert													
7	Keewatin													
8	Mountain Iron													
9	Pierz													
10	Proctor													
11	Randall													
12	Two Harbors													
13	Virginia													
14	Grand Rapids													
15	Excess Capacity													
16	GRE Capacity (Excess)													
17	Minnkota Power - Capacity													
18	Oconto - Capacity													
														TRADE SECRET DATA ENDS]
19	Total Capacity	$ 3,542,073	$ 3,500,148	$ 3,347,039	$ 3,381,917	$ 3,386,236	$ 3,505,584	$ 3,561,242	$ 3,534,268	$ 3,470,718	$ 3,534,036	$ 3,627,051	$ 3,662,769	$ 42,053,081
20	Energy	[TRADE SECRET DATA BEGINS												
21	Aitkin Public Utilities	[redacted]												
22	Biwabik Public Utilities													
23	Buhl													
24	Ely													
25	Gilbert													
26	Keewatin													
27	Mountain Iron													
28	Pierz													
29	Proctor													
30	Randall													
31	Two Harbors													
32	Virginia													
33	Grand Rapids													
34	Liquidation - Minnkota Power													
35	Liquidation Sales													
36	Market Sales													
37	Non-MP Station Service													
38	Oconto - Energy													
														TRADE SECRET DATA ENDS]
39	Total Energy	$ 9,056,993	$ 6,932,907	$ 6,998,340	$ 5,607,610	$ 6,184,999	$ 5,650,178	$ 8,333,957	$ 6,882,245	$ 2,764,346	$ 2,914,984	$ 3,595,660	$ 6,869,956	$ 71,792,175
40	Other	[TRADE SECRET DATA BEGINS												
41	Oconto Transmission	[redacted]												
														TRADE SECRET DATA ENDS]
42	Total Other	$ 117,301	$ 105,680	$ 113,934	$ 108,160	$ 110,601	$ 108,482	$ 114,537	$ 113,693	$ 108,074	$ 111,769	$ 111,091	$ 117,348	$ 1,340,670
43	Total Sales for Resale (Off-System)	$ 12,716,367	$ 10,538,735	$ 10,459,313	$ 9,097,687	$ 9,681,836	$ 9,264,244	$ 12,009,736	$ 10,530,206	$ 6,343,138	$ 6,560,789	$ 7,333,802	$ 10,650,073	$ 115,185,926

Line No.	Other Operating Revenue		Unadjusted Test Year 2022 Total Company (1)	Unadjusted Test Year 2022 Rider Recoverable (2)
1	Production			
2	Production-Demand			
3	CenturyLink (Rents Hydro Land for Building)	45400	$ 650	$ -
4	Recreation Leases	45610	$ 678,665	$ -
5	Timber Sales	45640	$ 6,000	$ -
6	Total Production-Demand		$ 685,315	$ -
7	Production-Energy			
8	Blandin Coal Shed Revenue	45690	$ 137,784	$ -
9	Blandin Coal Shed Revenue - WPPI	45690	$ (14,412)	$ -
10	Fly Ash Sales	45690	$ 1,058,313	$ -
11	ND ITC Used	45690	$ 106,694	$ -
12	Oconto - Renewable Resource Energy Credits - Offset in RRR	45690	$ 17,302	$ 17,302
13	Total Production-Energy		$ 1,305,681	$ 17,302
14	Total Production		$ 1,990,996	$ 17,302
15	Transmission			
16	GRE Communication	45400	$ 393,517	$ -
17	Hibbtac Transformer Rental	45400	$ 468	$ -
18	USS Fiber Rental	45400	$ 14,880	$ -
19	GRE (MISO Revenue Sharing)	45620	$ (692,297)	$ -
20	GRE JPZ	45620	$ 14,756	$ -
21	Manitoba Must Take Fee	45620	$ 20,860,385	$ 20,860,385
22	MISO	45620	$ 17,598,277	$ -
23	MISO Attachment O, GG, ZZ True Up - Accrual	45620	$ 308,700	$ -
24	MISO Sch 2 Transfer to Acc 55600 RC 0548	45620	$ (2,975,409)	$ -
25	MISO Sch2/3 Transfer to Acc 45660	45620	$ (1,115,275)	$ -
26	MP/Square Butte - DC Line	45620	$ 14,236,200	$ -
27	NERC Alert Projects - Schedule 45 (AC)	45620	$ 6,553,226	$ -
28	NERC Alert Projects - Schedule 45 (DC)	45620	$ 1,131,760	$ -
29	RECB Sch 26 (regional Expansion Cost & Benefit)	45620	$ 18,499,223	$ 18,499,223
30	RECB Schedule 37	45620	$ 202,320	$ 202,320
31	RECB Schedule 38	45620	$ 253,932	$ 253,932
32	WPPI	45620	$ 416,538	$ -
33	MISO Reactive Supp -transferred from 45620	45660	$ 1,115,275	$ -
34	ACE O&M Payment LGIA (Easement)	45690	$ 166,494	$ -
35	MH Joint Operating Expense Payments	45690	$ 10,759,932	$ 10,759,932
36	Total Transmission		$ 87,742,901	$ 50,575,792
37	Distribution			
38	Late Fees-CSA	45000	$ 645,000	$ -
39	Misc Serv Rev	45100	$ 90,000	$ -
40	AEP - Meter Data Management Service Charge	45690	$ 4,368	$ -
41	Brainerd - Metering Services Fee	45690	$ 4,800	$ -
42	Joint Use/Pole Att	45400	$ 391,090	$ -
43	Nashwauk/Essar Billing & Maint Fee	45690	$ 24,480	$ -
44	SWL&P TALA Lease Payment	45690	$ 39,529	$ -
45	Oconto - Meter Data Management Service Charge	45690	$ 21,649	$ -
46	Total Distribution		$ 1,220,915	$ -
47	General Plant			
48	Enventis Rents	45400	$ 406,700	$ -
49	Xcel	45400	$ 9,313	$ -
50	Misc Bldg Mtc Revenue	45690	$ 146,326	$ -
51	Tower Leasing	45690	$ 194,654	$ -
52	Total General Plant		$ 756,992	$ -
53	Cost Recovery Riders			
54	Conservation Improvement Program	45690	$ 1,750,087	$ 1,750,087
55	Solar Renewable Resources Rider	45690	$ 2,029,674	$ 2,029,674
56	Transmission Cost Recovery Rider	45690	$ 28,815,878	$ 28,815,878
57	Total Cost Recovery Riders		$ 32,595,639	$ 32,595,639
58	Total Other Operating Revenue		$ 124,307,444	$ 83,188,733

Adjustment	Interim	General	Required	Customary/ Voluntary	Requested	Workpaper Reference
Rate Base						
Asset Retirement Obligation	yes	yes	x			ADJ-RB-01
Cost to Retire	yes	yes	x			ADJ-RB-02
Decommissioning	yes	yes	x			ADJ-RB-03
Boswell 1 and 2 Regulated Asset	yes	yes	x			ADJ-RB-04
Boswell 3 Environmental Project	yes	yes	x			ADJ-RB-05
EV Program	yes	yes	x			ADJ-RB-06
EVSE Project	yes	yes	x			ADJ-RB-07
Pro Rata ADIT	yes	no	x			ADJ-RB-08
Aircraft Hangar	yes	yes		x		ADJ-RB-09
Continuing Cost Recovery Riders	yes	yes		x		ADJ-RB-10
DC Line Addition	yes	yes		x		ADJ-RB-11
OPEB	yes	no			x	ADJ-RB-12
Prepaid Pension	yes	no			x	ADJ-RB-13
Cash Working Capital	yes	yes		x		ADJ-RB-14
Changes in Allocations due to Adjustments	yes	yes		x		ADJ-RB-15
Income Statement						
Advertising Expense	yes	yes	x			ADJ-IS-01
Charitable Contributions	yes	yes	x			ADJ-IS-02
Economic Development	yes	no	x		x	ADJ-IS-03
Organizational Dues	yes	yes	x			ADJ-IS-04
Employee Expenses	yes	yes	x			ADJ-IS-05
Incentive Compensation	yes	yes	x	x		ADJ-IS-06
Investor Relations	yes	yes	x			ADJ-IS-07
Credit Card Fees	yes	yes	x			ADJ-IS-08
Asset Retirement Obligation	yes	yes	x			ADJ-IS-09
Decommisioning	yes	yes	x			ADJ-IS-10
Boswell 1 & 2 Regulated Asset	yes	yes	x			ADJ-IS-11
Boswell 3 Environmental Project	yes	yes	x			ADJ-IS-12
EVSE Project	yes	yes	x			ADJ-IS-13
Service Center Sales	yes	yes	x			ADJ-IS-14
Conservation Expense	yes	yes	x			ADJ-IS-15
Aircraft Hangar	yes	yes		x		ADJ-IS-16
CARE	yes	yes		x		ADJ-IS-17
CIP Incentive	yes	yes		x		ADJ-IS-18
CIP Carrying Charge	yes	yes		x		ADJ-IS-19
CPA Incentive	yes	yes		x		ADJ-IS-20
CPA	yes	yes		x		ADJ-IS-21
CCRC	yes	yes		x		ADJ-IS-22
Continuing Cost Recovery Riders	yes	yes		x		ADJ-IS-23
Rate Case Expense	yes	yes		x		ADJ-IS-24
Revenue Budget Corrections	yes	yes		x		ADJ-IS-25
Excess ADIT	yes	yes		x		ADJ-IS-26
DR Product A Reassign	no	yes			x	ADJ-IS-27
LP Demand Response	no	yes			x	ADJ-IS-28
Boswell Inspection Costs	yes	yes			x	ADJ-IS-29
Interest Synchronization	yes	yes		x		ADJ-IS-30
Changes in Allocations due to Adjustments	yes	yes		x		ADJ-IS-31