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August 15, 2019

VIA E-FILING
Mr. Daniel P. Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Renewable Resources Rider and 2020 Renewable Factor
Docket No. E015/M-19-____

Dear Mr. Wolf:

Enclosed please find Minnesota Power's Petition seeking Minnesota Public Utilities Commission approval of its 2020 Renewable factor. This Petition is filed pursuant to Minn. Stat. § 216B.1645, subd. 2a. Minnesota Power has included a Summary with this filing. As reflected in the Affidavit of Service, the Summary has been filed on the general service list utilized by Minnesota Power. Please call me at the number above with any questions related to this matter.

Yours truly,

Lori Hoyum

Lori Hoyum

LH:sr
Attach.
cc: Minnesota Power's General Service List

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STATE OF MINNESOTA
BEFORE THE
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SUMMARY

Minnesota Power submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. § 216B.1645 and Minn. Rules 7829.1300. Minnesota Power is seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd 2a to update cost recovery through Minnesota Power's Commission-approved Rider for Renewable Resources.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Renewable Resources Rider and 2020 Renewable Factor	Docket No. E015/M-19-XXX

I. INTRODUCTION

Minnesota Power (or "Company") submits this Petition to the Minnesota Public Utilities Commission ("Commission") pursuant to Minn. Stat. § 216B.1645 and Minn. Rules 7829.1300. Minnesota Power is seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd 2a to update cost recovery to account for reimbursements to customers in the form of credits through Minnesota Power's Commission-approved Rider for Renewable Resources ("Renewable Resources Rider" or "RRR"). Specifically, included are revenues the Company is receiving from the sale of renewable energy credits ("RECs") to Oconto Electric Cooperative ("Oconto"). Upon Commission approval, Minnesota Power will adjust the line item on customers' monthly electric bills under the Renewable Adjustment.

Minnesota Power has publically announced its intent to file its next general rate case[1] in early November 2019. As a result, costs related to the two remaining projects of the Thomson Hydroelectric Restoration Project ("Thomson Project") for which the Commission issued an order on March 5, 2015, finding that the Thomson Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures;[2] and credits to ratepayers related to the transfer of a Large Generator Interconnection Agreement ("LGIA"), referred to as the Bison 6 LGIA, to Minnesota Power's affiliate ALLETE Clean Energy, Inc. ("ACE");[3] have been removed from the RRR Tracker effective January 1, 2020. With Commission approval, Minnesota Power plans to include the Thomson Project costs and Bison 6 LGIA credit to customers as part of base rates in its forthcoming general rate case.

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[1] Docket No. E015/GR-19-442.
[2] The Company will request to move these projects into base rates in its forthcoming general rate case.
[3] March 16, 2018 *Order Approving Sale of Bison 6 Interconnection Agreement* in Docket No. E015/AI-17-304.

A. Background of the Renewable Resources Rider

On May 11, 2007, the Commission established Minnesota Power's Renewable Resources Rider through an order approving recovery of investments and expenditures for potential transmission upgrades for the Oliver Wind II power purchase agreement with FPL Energy allowed under Minn. Stat. § 216B.1645.[4] The Company subsequently utilized the RRR for the Bison Wind Energy Center ("Bison Wind"). Bison Wind is Minnesota Power's 496.6 megawatt ("MW") wind facility located in central North Dakota and developed over time in stages: Bison 1 (81.8 MW), Bison 2 (105 MW), Bison 3 (105 MW), and Bison 4 (204.8 MW). The initial Bison 1 project cost recovery began in 2010,[5] additional Bison 1, 2 and 3 cost recoveries started in late 2013,[6] and Bison 4 cost recovery started in June 2015.[7] Cost recovery for the Thomson Project began in April 2016.[8]

Minnesota Power filed its 2017 Renewable Resources Rider Factor Filing ("2017 Factor Filing") on November 2, 2016.[9] Since the proposed 2017 renewable resources factor resulted in a decrease in customer bills for most customers, and to allow cost recovery for RRR projects to be synchronized with the Company's 2016 general rate case ("2016 Rate Case") (also filed November 2, 2016),[10] the Commission waived the 90-day requirement of Minn. Rule 7825.3200 and granted provisional approval of the 2017 renewable factor on December 21, 2016, with implementation effective January 1, 2017. The Commission approved the 2017 Factor Filing in an Order dated November 8, 2017.

Minnesota Power filed its 2018 Renewable Resources Rider Factor Filing ("2018 Factor Filing)" on June 5, 2018.[11] Since all Bison Wind projects and most projects associated with the Thomson Project were rolled into base rates in the 2016 Rate Case, the Company requested Commission approval to recover updated tracker balance, updated investments and expenditures related to the two remaining projects associated with the Thomson Project, and true-up of actual production tax credits.[12] The

[4] Docket No. E015/M-07-216.
[5] Order issued July 21, 2010, in Docket No. E015/M-10-273.
[6] Order issued December 3, 2013,in Docket No. E015/M-13-410.
[7] Order issued May 22, 2015, in Docket No. E015/M-14-349.
[8] Order issued March 9, 2016, in Docket No. E015/M-14-962.
[9] Docket No. E015/M-16-776.
[10] Docket No. E015/GR-16-664.
[11] Docket No. E015/M-18-375.
[12] Compliance with Order Point 37 of the March 12, 2018 Order in Docket No. E015/GR-16-664.

Company included reimbursements of sums related to the Bison 6 LGIA.[13] The Commission approved the 2018 Factor Filing in an Order dated November 19, 2018.

On August 21, 2015, Minnesota Power filed a petition[14] with the Commission seeking approval to include costs of the Camp Ripley Solar Project through a new Solar Renewable Factor separate from the existing Renewable Resources Rider. The Commission issued an Order on February 26, 2016, approving the Company's petition, subject to certain compliance requirements which the Commission reviewed and approved in an order dated December 12, 2016. None of the costs associated with the Camp Ripley Solar Project have been included in this 2020 Renewable Resources Rider. Likewise, no costs associated with Minnesota Power's Commission-approved community solar garden pilot program[15] have been included. The Company expects to include the costs associated with these approved solar projects in a future Solar Renewable Factor filing.[16]

B. <u>Update to 2018 Tracker Balance</u>

The 2020 RRR calculations include an update to the 2018 tracker balances. The 2018 tracker balance includes recovery of cost for investments and expenditures incurred related to the Bison Wind and Thomson Projects. The Bison Wind and most of the projects associated with the Thomson Project were rolled into base rates in the 2016 Rate Case. The Company plans to request approval to roll the remaining two projects for the Thomson Project into base rates in its forthcoming general rate case; therefore, no new costs for these projects are included in the 2020 RRR calculations. Descriptions are provided for Bison Wind and Thomson Project due to their inclusion in the 2018 tracker balances.

1. Bison 1 Wind Project

On March 23, 2009, Minnesota Power submitted a petition seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 1 Project and associated transmission upgrades through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 1 Project is an 81.8 MW wind facility

[13] Compliance with Order Point 2 of the March 16, 2018 Order in Docket No. E015/AI-17-304.
[14] Docket No. E015/M-15-773.
[15] Docket No. E015/M-15-825.
[16] Certain retail customer defined in Minn. Stat. § 216B.1691, subd 2f "may not have included in the the rates charged to them by the public utility any costs of satisfying the solar standard specified by this subdivision." Minnesota Power has retail customers in the identified classifications, therefore, a separate Solar Renewable Factor is required for compliance with this statute.

located southwest of Center, North Dakota, with the wind energy applied towards Minnesota Power's requirements under the Renewable Energy Standard ("RES"). The Bison 1 Project included upgrading Minnesota Power's existing DC Line between the Square Butte Substation in Center, North Dakota, and Minnesota Power's Arrowhead Substation near Duluth. The upgrade increased the DC Line capacity from 500 MW to 550 MW, facilitating the deliverability and reliability of the Bison 1 Project.

On July 7, 2009, the Commission issued an order finding that Minnesota Power's Bison 1 Project, including transmission related components, qualifies as an eligible technology under Minn. Stat. § 216B.1691, its generated energy is a reasonable means by which to meet Minnesota Power's renewable energy standard obligations, and the project is prudent and reasonable when compared to alternative approaches for meeting these obligations.

2. Bison 2 Project

On March 24, 2011, Minnesota Power submitted a petition[17] seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 2 Project through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 2 Project is a 105 MW wind facility located in Oliver and Morton Counties in central North Dakota, with the wind energy applied towards Minnesota Power's requirements under the RES.

On September 8, 2011, the Commission issued an order finding that Minnesota Power's Bison 2 Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

3. Bison 3 Project

On June 21, 2011, Minnesota Power submitted a petition seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 3 Project through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 3 Project is also a 105 MW wind facility located in Oliver and Morton Counties in central North Dakota, with the wind energy applied towards Minnesota Power's requirements under the RES.

[17] Docket No. E015/M-11-234.

On November 2, 2011, the Commission issued an order finding that Minnesota Power's Bison 3 Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

4. Bison 4 Project

On September 27, 2013, Minnesota Power submitted a petition seeking Commission approval pursuant to Minn. Stat. § 216B.1645, subd. 1 for the investments and expenditures related to the development of the Bison 4 Project through Minnesota Power's Commission-approved Renewable Resources Rider. The Bison 4 Project is a 204.8 MW wind facility located in Oliver County in central North Dakota, with the wind energy applied towards Minnesota Power's requirements under the RES. The Bison 4 Project included expanding the existing Bison Substation, constructing a new Tri-County Substation, constructing 11 miles of 230 kV transmission line connecting the two substations, and integrating software to enhance voltage regulation. In addition, a component of this project involved upgrading the capacity of the Center-Heskett 230 kV transmission line that runs between Center and Mandan, North Dakota to support the injection of additional wind energy onto the alternating current (AC) system.

On January 17, 2014, the Commission issued an order finding that Minnesota Power's Bison 4 Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

5. Thomson Project

On July 3, 2014, Minnesota Power filed a petition[18] with the Commission seeking approval to include costs of a hydroelectric restoration project at the Company's Thomson Hydroelectric Facility through the Renewable Resources Rider. The Thomson Project was developed to restore 71 MW of renewable energy to the hydroelectric facility after it was severely damaged in record rainfall and flooding in June 2012. On March 5, 2015, the Commission issued an order finding that the Thomson Project qualifies as an eligible technology under Minn. Stat. § 216B.1691 and approved the related investments and expenditures.

[18] Docket No. E015/M-14-577.

C. Bison 6 LGIA Credit

Minnesota Power filed its Affiliate Interest Agreement petition between ALLETE, Inc. and ACE with the Commission on April 19, 2017, seeking approval to transfer the Bison 6 LGIA to ACE. At the time, the Company recommended crediting customers for certain costs related to the transfer through the renewable resource rider to facilitate the most expedient reimbursement since the Company was in the midst of the regulatory review process for its 2016 Rate Case. The Commission approved the Bison 6 LGIA transfer and crediting customers through the renewable resources rider in an Order dated March 16, 2018. On April 17, 2018 and May 7, 2018, the Company filed Compliance Filings with the Commission which provided the detail of these cost amounts. The 2018 RRR calculations included reimbursements as documented in the Company's April 17, 2018 and May 7, 2018 Compliance Filings.

As previously stated, Minnesota Power has publically announced its intent to file its next general rate case in early November 2019. Given the close timing of the forthcoming rate case and the regulatory review process of the 2020 Renewable Resources Factor, the Company is requesting Commission approval to reimburse customers through base rates. In order to make the reimbursement for the Bison 6 LGIA transfer costs permanent, Minnesota Power will reflect payment from ACE for Bison 6's share of capital costs spent on transmission line and related facilities supporting the Bison 6 LGIA as contribution in aid of construction in the forthcoming general rate case. This will reduce net plant and depcreciation expense in the the forthcoming rate case. Customers will effectively be reimbursed through their base rates beginning January 1, 2020, ending the need to make the same credit in the RRR. Therefore, 2020 RRR calculations exclude reimbursement to customers for the Bison 6 LGIA effective January 1, 2020. The Company commits to continued reporting on the requirements identified in Order Points 2.A., 2.B., and 2.C. of the March 16, 2018 Order in Docket No. E015/AI-17-304 in the RRR including:

- An accounting of costs incurred, including all legal, state and federal regulatory costs;
- Reimbursement to customers for Bison 6's share of capital costs spent on transmission line and related facilities supporting the Bison 6 LGIA;
- Reimbursement to customers equal to the revenue requirement – both return on equity and depreciation from Bison 6's share of transmission costs allocated to ACE; and

- Reimbursement to customers of Bison 6's share of costs to operate and maintain the transmission facilities.

In the event the Commission denies the request to reimburse customers through base rates, the credit would continue in the renewable resources rider retroactive to January 1, 2020.

D. Renewable Resources Factor

The Company's proposed 2020 Renewable Factor will result in a rate increase for all customer classes except the large power ("LP") customer class. The impact for the average residential customer will be an increase of about 2.64 percent. The LP average class rate will stay about the same, but decreases by 0.09 percent compared to the 2018 Renewable Resources Factor that is currently being applied to customer bills.

Minnesota Power is proposing to transfer the two remaining Thomson Projects and the LGIA credit included in the Renewable Resources Rider to base rates coinciding with the start of the forthcoming general rate case interim rate period on January 1, 2020. As a result, the 2020 Renewable Resources Factor that Minnesota Power is seeking to place on customer bills consists mostly of the projected December 31, 2019 tracker balance, with a minor contribution in 2020 due to the credit related to the RECs sold to Oconto.

II. PROCEDURAL MATTERS

Pursuant to Minn. Stat. § 216B.16, subd. 1 and Minn. Rule 7829.1300, Minnesota Power provides the following required general filing information.

A. Summary of Filing (Minn. Rule 7829.1300, subp.1)

A one-paragraph summary accompanies this Petition.

B. Service on Other Parties (Minn. Rule 7829.1300, subp. 2)

Pursuant to Minn. Stat. § 216.17, subd. 3 and Minn. Rules 7829.1300, subp. 2, Minnesota Power eFiles the Petition on the Minnesota Department of Commerce Division of Energy Resources and the Minnesota Office of the Attorney General – Antitrust and Utilities Division. A summary of the filing prepared in accordance with Minn. Rules 7829.1300, subp. 1 is being served on Minnesota Power's general service list.

C. Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 3(A))

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

D. Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 3(B))

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E. Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 3(C))

This Petition is being filed on August 14, 2019. Minnesota Power proposes that the 2020 Renewable Factor take effect the first of the month following Commission approval and no sooner than 90 days from the Petition filing date.

F. Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 3(D))

This Petition is made pursuant to Minn. Stat. § 216B.1645, subd. 2a. Minn. Rule 7825.3200 requires that utilities serve notice to the Commission at least 90 days prior to the proposed effective date of modified rates. Furthermore, Minnesota Power's proposed 2020 Renewable Resources Factor falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4 permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

G. Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 3(E))

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H. Impact on Rates and Services (Minn. Rule 7829.1300, subp. 3(F))

The 2020 Renewable Resources Factor will have no effect on Minnesota Power's base rates. The additional information required under Minn. Rule 7829.1300, subp. 3(F) is included throughout this Petition.

I. Service List (Minn. Rule 7829.0700)

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III. RENEWABLE RESOURCES RIDER AUTHORIZATION

Minn. Stat. § 216B.1645, subd. 2a allows the Commission to approve a schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the Commission. Under Minn. Stat. § 216B.1645, subd. 2a, the Commission may approve, or approve as modified, a rate schedule that:

(1) allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:

(i) return on investment;
(ii) depreciation;
(iii) ongoing operation and maintenance costs;
(iv) taxes; and
(v) costs of transmission and other ancillary expenses directly allocable to transmitting electricity generated from a project meeting the specifications of this paragraph;

(2) provides a current return on construction work in progress, provided that recovery of these costs from Minnesota ratepayers is not sought through any other mechanism;

(3) allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;

(4) allocates recoverable costs appropriately between wholesale and retail customers; and

(5) terminates recovery when costs have been fully recovered or have otherwise been reflected in a utility's rates.

IV. 2020 RENEWABLE RESOURCES FACTOR

There are no new costs related to renewable facilities to document under sections: *A. Description of Facilities (Minn. Stat. § 216B.1645, subd. 2a(b)(1))*, and *B. Description of Facilities (Minn. Stat. § 216B.1645, subd. 2a(b)(1))*. Details on the Thomson Project are provided as a courtesy to confirm completion of the remaining two projects and highlight the benefit to customers from their investment in preserving the largest hydroelectric facility in Minnesota.

A. Description of Facilities (Minn. Stat. § 216B.1645, subd. 2a(b)(1))

As detailed in Minnesota Power's July 3, 2014, Petition,[19] the Thomson Project is a 71 MW hydroelectric restoration project located at the Thomson Development in Minnesota Power's St. Louis River Hydro System. The Thomson facility was severely damaged and brought offline by record rainfall and flooding in June 2012. The project was to restore the facility from the damages and upgrade Thomson to meet current safety and engineering standards. Specifically, the project included reconstruction of the forebay canal embankment, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system, construction of a passive, concrete overflow spillway on the forebay canal, and the raising of the dams/embankment comprising the Thomson Reservoir.

The Company is pleased to report that the Thomson Project has resulted in improved efficiency of the units resulting in an increase of generation capability from pre-reconstruction levels. The Thomson station is now capable of nearly 75 MW at peak production.

B. Project Schedule (Minn. Stat. § 216B.1645, subd. 2a(b)(2))

The Thomson Project is complete. On October 9, 2014, the forebay reconstruction was completed and the forebay was subsequently refilled. Work related to the electrical restoration, mechanical and general civil rehabilitation, and upgrades to the water conveyance system has also been completed. All portions of the Thomson Project were completed by the end of 2016 except for the spill capacity projects. The spill capacity projects were anticipated to be completed by the end of 2017, pending necessary authorization and design approvals by the Federal Energy Regulatory Commission. The last of the spillway work was completed in late 2018.

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[19] Docket No. E015/M-14-577.

C. <u>Minnesota Power's Costs (Minn. Stat. § 216B.1645, subd. 2a(b)(3 & 4))</u>

Minnesota Power has employed multiple steps to help ensure the lowest costs to customers on the Thomson Projects. Minn. Stat. § 216B.1645, subd. 2a(b)(4). Minnesota Power utilized its standard purchasing procedures to obtain competitive quotations for most major purchases and awarded contracts to the lowest bidder(s), unless a better overall value could be obtained. In some cases, contracts were awarded on a single source basis to qualified contractors based on utilizing existing partnering agreements or based upon original equipment manufacturer considerations. Minnesota Power will provide any additional information deemed necessary, as part of notice and comment, for the Commission to conclude that "the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred." Minn. Stat. § 216B.1645, subd. 2a(b)(4).

Based on the original Petition, Minnesota Power anticipated that the Thomson Project would cost approximately $90.4 million, net of insurance proceeds. The total project cost for the Thomson Project was finalized at $93.3 million, net of insurance proceeds. In order to remain within the maximum level of capital expenditures approved in the original Petition, capital expenditures, net of insurance proceeds, were capped in the 2017 Renewable Resources Factor at $90.4 million. After deducting internal costs, allowance for funds used during construction ("AFUDC") on internal costs, and wholesale AFUDC, the capital expenditures for calculating revenue requirements was capped at $84.1 million, which is equal to the amount of capital expenditures utilized for calculating revenue requirements in the original Petition. Refer to Exhibit B-3 for additional detail on Thomson Project expenditures utilized in calculating the revenue requirements. The final total cost for the Thomson Project is about $2.9 million (or about 3 percent) above the cap of $90.4 million set in the 2017 Factor Filing. The difference is not attributable to any certain project costs. Rather, the preliminary project cost estimate was developed during the initial design stage. As the Company progressed from the initial design stage through the planning, procurement and construction stages the costs for this unique and substantial project became more certain.

1. Production Tax Credit True-ups

The Commission's March 12, 2018 Order in the Company's 2016 Rate Case directed Minnesota Power to perform an annual true-up of actual production tax credits through the Renewable Resources Rider (see Order Point 37). Those amounts have been included in the calculation of the RRR factor as shown in Exhibit B-1, page 1, and are shown in detail in Exhibit B-2, page 8.

2. Reimbursements for Oconto RECs

Minnesota Power entered into a power sales agreement with Oconto that includes selling excess renewable energy credits to assist Oconto in meeting Wisconsin's Renewable Portfolio Standard. This contract is effective from January 2019 through May 2026, and appropriately compensates customers for the sale of the RECs. Minnesota Power expects to transfer approximately 6,500 RECs annually to Oconto. Selling RECS to Oconto will have no impact on the Company's ability to meet it obligation as set forth in Minnesota's RES (Minn. Stat. § 216B.1691, subd. 3(b)). Minnesota Power expects to maintain RES compliance through 2053 with its current renewable portfolio, the longest duration of any utility in Minnesota.[20] The Company has included a reimbursement to customers for the revenue it is receiving from the sale of the RECs. Those amounts have been included in the calculation of the RRR factor as shown in Exhibit B-1, page 1.

D. <u>Revenue Requirements</u>

The total recoverable Retail revenue requirements for the 2020 Renewable Resources Rider are $1.1 million, consisting of a $1.1 million tracker balance estimated through the end of 2019, and about a $15,000 revenue credit related to the RECs sale to Oconto. Even though the overall tracker balance shown in Exhibit B-1 is small at $1.1 million it consists of a projected credit balance for Large Power Class of -$4.8 million and a projected balance of $5.9 million for All Other Classes.

The 2020 Renewable Adjustment Factors shown in Exhibit A-1 are proposed to be effective the first day of the first month following the Commission order or January 1, 2020 to coincide with the Company's anticipated effective date of interim rates in its forthcoming general rate case. Exhibit B-1, page 1, summarizes the revenue requirements, cost allocation, and rate design. Exhibit B-1, page 2, provides a summary starting with the 2017 ending tracker and moving forward in time to project a 2019 ending tracker balance. Exhibit B-1, pages 3 to 5 summarize the 2018, 2019 and 2020 trackers. The revenue requirement calculations for the two remaining Thomson projects are shown for 2018 and 2019 in Exhibit B-2 on pages 1 to 4 (in 2020 revenue requirements are anticipated to be zero as Minnesota Power expects to transfer the projects to base rates). Exhibit B-2 also includes the calculation of the Thomson Base Rate Revenue Credit, the revised LGIA Credit, and the Production Tax Credits ("PTC")

[20] See the Department of Commerce, Division of Energy Resources Report to the Minnesota Legislature on Progress on Compliance by Electric Utilities with Minnesota Renewable Energy Objective and the Renewable Energy Standard dated January 15, 2019 (page 11); filed on May 30, 2019, in Docket No. E015/M-18-78.

True-ups for 2018 and 2019. It should be noted that a PTC True-up is not budgeted in 2020, as 2020 will be a rate case test year and a variance between the 2020 test year and 2020 budget would not exist. However, as 2020 actual wind generation comes in, a PTC True-up to record the variance between 2020 actual generation and the 2020 test year budget will be entered into the tracker. Exhibit B-3 shows the capital expenditure details for the remaining two Thomson projects. Exhibit B-4 includes the rates of return applied in the tracker, and Exhibit B-5 includes the allocation factors from Minnesota Power's previous rate cases that are used to allocate costs to jurisdiction and then to subsequently allocate costs between Large Power and all other classes. A description of the revenue requirement components is provided below.

1. Return on Construction Work in Progress ("CWIP")

Minnesota Power recorded capital expenditures related to the Renewable Resources Rider in Federal Energy Regulatory Commission ("FERC") Account 107 – CWIP. Minnesota Power requested a current return on CWIP on the components that were not yet placed in-service beginning when cost recovery under the Rider was approved by the Commission. A return on CWIP was the only component of revenue requirements recovered under the Rider until the components not yet in-service were placed in-service. Consistent with the terms of the 2011 Transmission Cost Recovery Factor Filing[21] and subsequent filings, internal capitalized costs were excluded from the CWIP balances as shown in Exhibit B-3 for the Thomson Project. In compliance with the terms of the 2013 Renewable Resources Factor Filing,[22] AFUDC on internal capitalized costs was excluded from CWIP balances as shown in Exhibits B-3.

a) Allowance for Funds Used During Construction

The Company calculated AFUDC for the Bison and Thomson Projects and recorded an offsetting regulatory liability (referred to as a "contra" entry) equaling 100 percent of the projects' AFUDC excluding AFUDC on internal costs and included that regulatory liability as a reduction to rate base through an entry to "Pre-funded AFUDC Regulatory Liability." After the projects were placed in-service, the amount of the Pre-funded AFUDC Regulatory Liability started being amortized over the lives of the projects.

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[21] Docket No. E015/M-11-695.
[22] Docket No. E015/M-13-410.

In a December 2010 Order, FERC prescribed specific accounting treatment, which requires the Company to record the Pre-funded AFUDC Regulatory Liability by debiting Account 407.3, Regulatory Debits, and crediting Account 254, Other Regulatory Liabilities, in accordance with the instructions of those accounts. In addition, the Company started amortizing the Pre-funded AFUDC Regulatory Liability as an offset to depreciation expense by debiting Account 254 and crediting Account 407.4, Regulatory Credits. The Company maintained all necessary controls to ensure the amount of the Pre-funded AFUDC Regulatory Liability recorded in Account 254 includes the total amount of AFUDC accrued on the projects excluding AFUDC on internal costs. This FERC-approved methodology for the application of AFUDC is currently being applied to all Minnesota Power current cost recovery rider projects.

b) Return on Investment – CWIP

Revenue requirements during the construction phase of the projects were based on the average monthly CWIP balance of the Thomson Projects. The Return on Investment – CWIP was calculated on the average of the beginning and ending monthly CWIP balance until the projects were placed in-service. The components of the revenue requirement included an after-tax return on equity component, current and deferred income taxes, and interest expense. The total annual revenue requirements were the sum of the monthly current return on CWIP calculations until the projects were placed in-service. At that time, the ending CWIP balance was transferred to plant in-service and Minnesota Power began to recover full revenue requirements. Internal capitalized costs and AFUDC on internal costs were excluded from the CWIP balances as shown in Exhibits B-3.

(i) Return on Equity Component

The return on investment is based on Minnesota Power's last retail rate case.[23] Minnesota Power used the average monthly CWIP balance multiplied by the after-tax equity return rate and the equity percentage of the allowed capital structure from the last rate case to calculate the return on equity component of the revenue requirement calculation.

[Return on Equity Component = Average Monthly CWIP Balance X After-Tax Equity Return Rate X Capital Structure Equity Percentage]

[23] Docket No. E015/GR-16-664.

(ii) Income Tax Expense Component

Minnesota Power included a component of the revenue requirement calculation to recover the effective rate of taxes. This represents both current and deferred income taxes. The income tax amount is based upon the Return on Equity component of the revenue requirement to equate it to a pretax amount.

[Income Taxes = Return on Equity Component X 1/(1-28.742%) X 28.742%]

(iii) Interest Expense Component

Minnesota Power included a component of the revenue requirement calculation to recover an equivalent amount of interest expense that would be incurred given the investment in the Bison and Thomson Projects. The interest component was calculated based on the average monthly CWIP balance times the debt rate approved in the last rate case times the debt percentage of the allowed capital structure from the last rate case.

[Interest Expense = Average Monthly CWIP Balance X Debt Rate X Capital Structure Debt Percentage]

(iv) Thomson Base Rate Revenue Credit

The Minnesota Jurisdictional Revenue Requirements included a credit for plant equipment that was retired as a result of the Thomson Project. Equipment with original installed cost of approximately $121,000 was retired as part of the Thomson Spill Capacity Project. The estimated jurisdictional revenue requirements associated with this equipment that are currently in base rates were deducted from the Thomson Project jurisdictional revenue requirements. This credit includes a return on average rate base, depreciation expense, and associated property tax. This credit began with the completion of the project in December 2017, and will continue until the Thomson Project revenue requirements are rolled into base rates January 1, 2020. Refer to Exhibit B-2, page 5, for the calculation of this credit that can be seen in the 2018 and 2019 trackers (Exhibit B-1 pages 3-4, line 19).

(v) Property Taxes

Any Minnesota property taxes that Minnesota Power is required to pay on CWIP that is in-place is included in the project revenue requirements.

2. Full Revenue Requirements – In-service

Full revenue requirements are based on the Original Installed Cost ("OIC") now that the Thomson Projects were placed in-service. Internal capitalized costs and AFUDC on internal costs are excluded from the OIC balances as shown in Exhibit B-3. As described in greater detail below, the in-service revenue requirements will be calculated using the adjusted average monthly rate base for the projects plus related expenses. The components of the revenue requirements for the Thomson Projects will include an after-tax return on investment, current and deferred income taxes, interest expense, depreciation expense, and property taxes.

a) Adjusted Average Rate Base

Adjusted average rate base will be calculated using the monthly balance of the Thomson Projects' OIC reduced by the accumulated depreciation for the projects. The adjusted average rate base will also be adjusted for any differences between book and tax depreciation expense through accumulated deferred income taxes.

b) Return on Equity Component

The return on investment calculation will be based on Minnesota Power's last retail rate case.[24] Minnesota Power will use the average monthly adjusted rate base multiplied by the after-tax equity return rate and the equity percentage of the allowed capital structure from the last rate case to calculate the return on equity component of revenue requirements.

[Return on Equity Component = Average Monthly Adjusted Rate Base X After-tax Equity Return Rate X Capital Structure Equity Percentage]

c) Income Tax Expense Component

Minnesota Power will include a component of the revenue requirement calculation to recover the effective rate of taxes. This represents both current and deferred income taxes. The income tax amount will be based upon the Return on Equity component of the revenue requirement to equate it to a pre-tax amount.

[Income Taxes = Return on Equity Component X 1/(1-28.742%) X 28.742%]

[24] Docket No. E015/GR-16-664.

d) Interest Expense Component

Minnesota Power will include a component of the revenue requirement calculation to recover an equivalent amount of interest expense that would be incurred given the investment in the two remaining Thomson Projects. The interest component will be calculated based on the average monthly adjusted rate base times the debt rate approved in the last rate case times the debt percentage of the allowed capital structure from the last rate case.

[Interest Expense = Average Monthly Adjusted Rate Base X Debt Rate X Capital Structure Debt Percentage]

e) Depreciation Expense Component

Once the assets are placed in service, depreciation on the Thomson Projects will be recovered through the Rider. Depreciation expense will be calculated on a straight line basis over the lives of the projects on the components and will begin as the assets are placed in-service.

f) Property Tax Component

Property taxes on the Thomson projects are included based upon the value of the property and applicable tax rates.

g) O&M Expense Component

No incremental O&M expenses related to the Thomson Project are included in the calculation of revenue requirements for the Renewable Resources Factor.

h) North Dakota Investment Tax Credits

The Bison Projects qualify for the North Dakota Investment Tax Credit ("ND ITC").[25] Currently no North Dakota income taxes are charged to revenue requirements. To the extent Minnesota Power generates taxable income in North Dakota in the future, any resulting income taxes will be offset by the use of this nonrefundable credit. Where possible, the Company is offsetting Renewable Resources Rider revenue requirements with ND ITC generated to-date and will continue to do so in the future. Based upon Minnesota Power's current estimates of corporate North Dakota income taxes, it is not anticipated that the Company will be able to fully utilize these tax credits at this time.

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[25] See Docket No. E015/M-14-962 (*Order Reconsidering Treatment of North Dakota Investment Tax Credits for Bison Wind Projects).*

i) Thomson Investment Tax Credits

Federal investment tax credits ("ITCs") are currently available for qualified renewable energy projects. In tax year 2015, the Thomson Project qualified for $24.3 million of federal ITCs under Internal Revenue Service ("IRS") guidance pertaining to when a rebuilt renewable asset will qualify as a new asset for purposes of earning a tax credit. As a result of Minnesota Power's tax net operating losses ("NOL"), the cash benefit of the federal ITCs from this project has not been realized, but deferred for future utilization. Under IRS normalization rules Minnesota Power cannot begin to amortize the benefit of this new federal ITC until it is utilized in a subsequent tax year. Minnesota Power currently anticipates fully utilizing the NOL carryforward in approximately 2020, and at that time will begin using the Minnesota Power tax credit carryforwards. Minnesota Power has other tax credit carryforwards in addition to the Thomson ITC. The tax credit carryforwards are used in a specific order that is determined by tax regulations. Based on this ordering, Minnesota Power anticipates using the Thomson ITC starting in approximately 2023. Once the federal ITC is utilized, Minnesota Power will begin amortizing the benefit of these federal ITCs to reduce regulatory tax expense in a future rate case, or revenue requirements in a future factor filing. The Thomson ITCs will have no impact on revenue requirements in this filing; they are included in the filing discussion to provide full transparency of the full costs and benefits generated from this project.

j) Thomson Base Rate Revenue Credit

The Minnesota Jurisdictional Revenue Requirements include a credit for plant equipment that was retired at the end of the Thomson Spill Capacity Project. Equipment with original installed cost of approximately $121,000 was retired as part of the Thomson Spill Capacity Project. The estimated jurisdictional revenue requirements associated with this equipment that are currently in base rates are deducted from the Thomson Project jurisdictional revenue requirements. This credit includes a return on average rate base, depreciation expense, and associated property tax. This credit began with the completion of the project in December 2017, and will continue until the Thomson Project revenue requirements are rolled into base rates January 1, 2020. Refer to Exhibit B-2, page 5, for the calculation of this credit that can be seen in the 2018 and 2019 trackers (Exhibit B-1 pages 3-4, line 19).

E. Rate Calculation and Customer Impact

Minnesota Power has calculated its proposed 2020 Renewable Adjustment Factors as shown in Exhibit A-1. Minn. Stat. § 216B.1645, subd. 2a(b)(3). Exhibit B-1, page 1, summarizes the revenue requirements, tracker balance, cost allocation, and rate design for the 2020 Renewable Adjustment Factors. Minnesota Power proposes to maintain the current Renewable Adjustment Factor rate design that incorporates demand ($/kW-month) and energy (¢/kWh) adders for the LP class and an average energy (¢/kWh) adder that is applied to all other retail classes. Specifically, the LP revenue requirements are split between demand and energy based on LP's base rate demand and energy revenue split of approximately 56 percent demand and 44 percent energy as approved by the Commission in Minnesota Power's last retail rate case[26] and as approved in the 2018 Renewable Factor Filing. The LP demand rate adder will be calculated as 56 percent of the projected LP revenue requirement divided by the LP class Billing Demand (kW-month) from Minnesota Power's most recent budget. The LP energy rate adder will be calculated as 44 percent of the projected LP revenue requirement divided by the LP energy (kWh) sales from Minnesota Power's most recent budget. The Renewable Adjustment Factor for the other Non-LP classes will continue to be calculated as an average energy-based (¢/kWh) charge consisting of the projected revenue requirements divided by the total energy (kWh) sales of the other Non-LP classes from Minnesota Power's most recent budget.

Minnesota Power has utilized the appropriate authorized rates of return, the jurisdictional Power Supply Production Demand allocators, and the jurisdictional Power Supply Transmission Demand allocators, based on those approved by the Commission in Minnesota Power's last retail rate case and as approved in the 2018 Renewable Resources Rider Factor filing. Refer to Exhibit B-4 for authorized rates of return, and to Exhibit B-5 for the allocation factors from Minnesota Power's last retail rate case.

1. Tracker Mechanism

In support of the Renewable Resources Rider Factor filings, Minnesota Power has implemented a tracker mechanism to account for the balance of actual revenue requirements and cash collected from customers. The trackers indicate the actual monthly Minnesota jurisdictional revenue requirements, actual cash collections, and over/under balances. Refer to Exhibit B-1, pages 3 to 5 for the Renewable Resources Rider trackers.

[26] Docket Nos. E015/GR-16-664.

2. Production Tax Credits

Minnesota Power has implemented a true-up procedure to account for differences in PTCs generated by the Bison Wind Energy Center as compared to what has been included in base rates in Minnesota Power's most recent retail rate case. This is Order Point No. 37 in the 2016 retail rate case initial order, Docket No. E-015/GR-16-664 dated March 12, 2018.

Minnesota Power's 2016 retail rate case was based on a 2017 test year. The 2017 cost of service included a tax benefit of $41.83 million related to production tax credits. In the 2020 Renewable Resources Rider, there will be a true-up to adjust for the difference between this amount and actual PTCs as determined based on actual wind generation. The true-up amount in the 2020 Renewable Resources Rider is $7.6 million consisting of $6.1 million for the 2018 PTC true-up and a projected true-up of $1.5 million in 2019 (based on actuals through May, and budget for the remainder of 2019). Likewise, the 2018 Renewable Resources Rider included an adjustment for the 2017 actual wind generation.

3. Deferred Taxes

a) Pro rata calculation

Under Internal Revenue Code Section 167(1), rate-regulated utilities that utilize accelerated tax depreciation are required to use a normalization method of accounting. If a future test year, or a part historical and part future test year are utilized when determining the reserve for deferred taxes for the reduction of rate base, then a specific pro rata calculation must be utilized to avoid a normalization violation. In this Renewable Resources Rider current cost recovery filing, the Company is utilizing a 2020 test year. As a result of rolling projects into base rates on January 1, 2020, there are no deferred taxes associated with the 2020 Renewable Resources Rider revenue requirements, and therefore no pro rata calculation is required for this current cost recovery filing.

b) Tax Reform

In Commission Docket No. G-999/CI-17-895, *In the Matter of a Commission Investigation into the Effects on Electric and Natural Gas Utility Rates and Services of the 2017 Federal Tax Act*, the Commission ordered[27] Minnesota Power to return its Tax Cuts and Jobs Act benefits of the excess accumulated deferred income taxes ("ADIT") impacts that existed at December 31, 2017 in a separate rider, as final rates in the most recent rate case were already implemented. Minnesota Power has

[27] Order dated May 10, 2019.

implemented the rider and is returning all of the excess ADIT benefits through that rider. As no additional excess ADIT impacts exist in this rider nothing has been included for excess ADIT in this rider.

4. Customer Impact

Table 1 below summarizes the estimated rate impacts by customer class assuming the 2020 Renewable Factors are implemented on January 1, 2020. The rate increase/decrease in cents per kWh shown in Table 1 below is the incremental change between the current 2018 Renewable Factors and the 2020 Renewable Factors in this filing.

Based on the above assumptions, all of the Non-LP classes would have an average rate increase of about 0.286 cents per kWh. For an average residential customer this would be about a 2.64% increase of about $2.07 more per month. The LP average class rate would remain nearly the same with a small decrease of 0.006 cents per kWh or a decrease of about 0.09%.

Table 1. Estimated Customer Impact

Rate Class Impacts 1/	
Residential	
Average Current Rate (¢/kWh)	10.846
Increase (Decrease) (¢/kWh)	0.286
Increase (Decrease) (%)	2.64%
Average Impact ($/month)	$2.07
General Service	
Average Current Rate (¢/kWh)	10.805
Increase (Decrease) (¢/kWh)	0.286
Increase (Decrease) (%)	2.65%
Average Impact ($/month)	$7.86
Large Light & Power	
Average Current Rate (¢/kWh)	8.247
Increase (Decrease) (¢/kWh)	0.286
Increase (Decrease) (%)	3.47%
Average Impact ($/month)	$706
Large Power	
Average Current Rate (¢/kWh)	6.176
Increase (Decrease) (demand + energy combined) (¢/kWh)	(0.006)
Increase (Decrease) (%)	(0.09%)
Average Impact ($/month)	($3,188)

Lighting	
Average Rate (¢/kWh)	16.171
Increase (Decrease) (¢/kWh)	0.286
Increase (Decrease) (%)	1.77%
Average Impact ($/month)	$0.96

Notes:
1/ Average current rates are 2019 estimated rates based on Final 2017 TY General Rates in 2016 Rate Case (E-015/GR-16-664) without riders adjusted to include current rider rates. Current rider rates include Renewable Resources Rider rates, Transmission Cost Recovery Rider rates, Boswell 4 Emission Reduction rates, Conservation Program Adjustment rates, and estimated 2019 Fuel and Purchased Energy. Average $/month impact based on 2020 budgeted billing units. The increase/decrease in cents/kWh is the incremental increase/decrease due to the new factor being implemented.

F. Project Benefits in Promoting Renewable Energy (Minn. Stat. § 216B.1645, subd. 2a(b)(5))

The project benefits in promoting renewable energy were described in Minnesota Power's initial plan filings for each of the projects and confirmed by Commission Order for the Bison and Thomson Projects. Together these projects are key components of Minnesota Power's proactive renewable plan to cost effectively meet Minnesota's 25 percent by 2025 RES.

V. BISON WIND PRODUCTION

In compliance with Order Point 4 of the November 19, 2018 Order in Docket No. E015/M-18-375, Minnesota Power provides "the actual production for the Bison projects over the prior year and explains the underperformance compared to the 1,888,000 megawatt-hours assumed in the eligibility filings." The data is for actual production at Bison Wind for the period beginning July 1, 2018 through June 30, 2019.

In 2018, Bison Wind generated 1,496,131 MWh (megawatt hours), which was below the total of the energy estimates assumed in the eligibility filings. This was primarily due to below-average wind speeds in 2018. The Oliver County I and II wind farms are located near the Bison site and experienced similar low wind speeds in 2018, resulting in lower production. See Figure 1 below. Additionally, the Bison 4 Project wind turbines experienced a high number of inverter module failures in 2018, resulting in lower availability. In response to the high failure rate, the turbine manufacturer replaced all Bison 4 Project inverter modules with improved design modules to correct the problem.

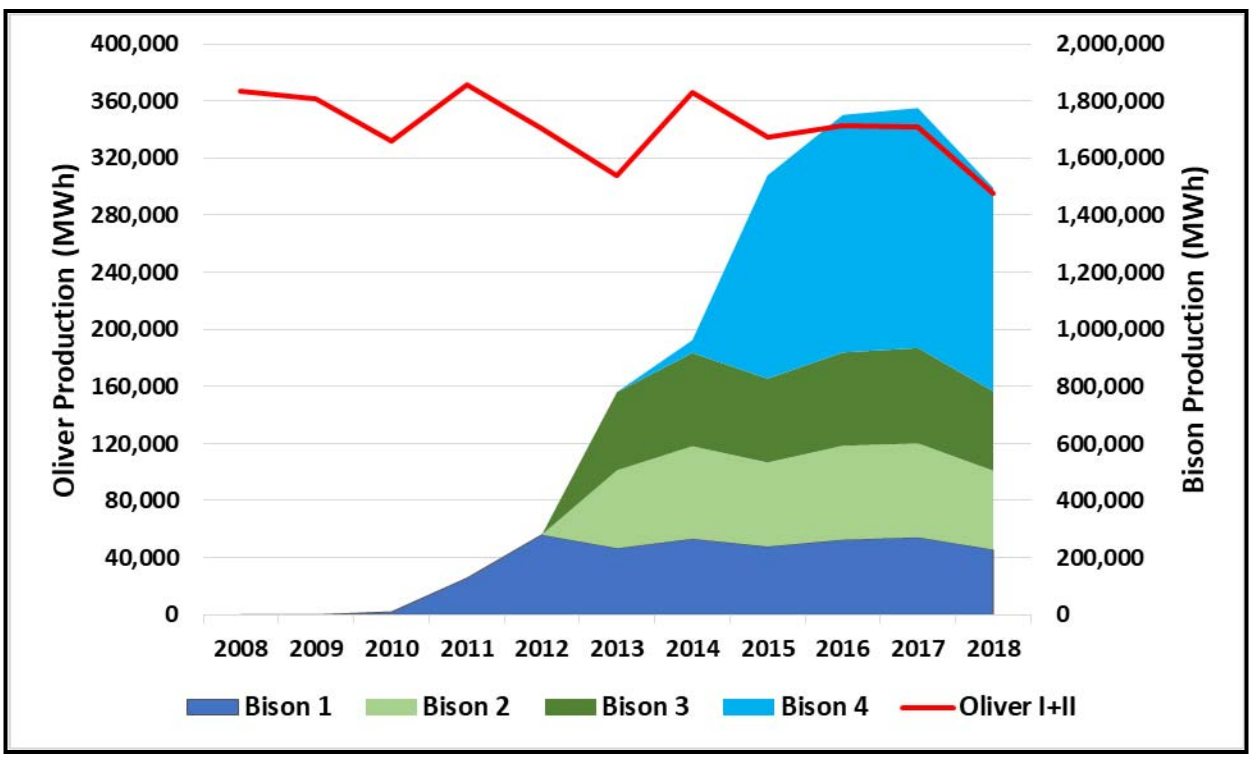

Figure 1 - Annual Production

VI. CONCLUSION

Minnesota Power's energy mix has changed a lot in recent years and continues to evolve through the Company's *Energy**Forward*** strategy. With investment in projects such as the 500 MW Bison Wind Center, and Thomson Project, the Company expects 45 percent of the power it produces to come from renewables by 2025. The Company respectfully requests that the Commission approve rolling cost recovery into base rates for the remaining two Thomson Projects and Bison 6 LGIA credit; approve the annual rate adjustment factor; and discontinue the requirement to report on Bison Wind production as part of its Renewable Resources Rider.

Dated: August 14, 2019

Respectfully submitted,

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RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	-$0.35 per kW-month for all Billing Demand kW and -0.040¢ per kWh for all kWh
All other applicable Retail Rate Customers	0.190¢ per kWh for all kWh

RIDER FOR RENEWABLE RESOURCES

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules – Rate Codes 73 and 79. In addition, this Rider is applicable to service under Company's Rider for Large Power Interruptible Service and Rider for Large Power Incremental Production Service.

The following charges are applicable in addition to all charges for service being taken under Company's standard rate schedules:

Large Power Customers	~~$0.33~~ $0.35 per kW-month for all Billing Demand kW
	and
	~~0.037~~ 0.040¢ per kWh for all kWh
All other applicable Retail Rate Customers	~~0.096~~ 0.190¢ per kWh for all kWh

Filing Date ______ **MPUC Docket No.** ______

Effective Date ______ **Order Date** ______

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

Minnesota Power
2020 Renewable Resources Rider
Summary: Revenue Requirements, Cost Allocation and Rate Design

		MN Jurisdictional Amounts Total
Projected 2019 Rider Ending Tracker Balance (Over) / Under Collection 1/		
MN Jurisdictional & Class Tracker		$ 1,138,651
Large Power		$ (4,751,165)
All Other Retail Classes		$ 5,889,816
2020 Net Revenue Requirements 2/		
MN Jurisdictional & Class Revenue Requirements		$ (15,470)
Large Power		$ (9,542)
All Other Retail Classes		$ (5,929)
Total 2020 RRR Factor Revenue Requirements		
MN Jurisdictional & Class Revenue Requirements		$ 1,123,181
Large Power		$ (4,760,707)
All Other Retail Classes		$ 5,883,887
Billing Units 3/		
Large Power	kW - month	630,521
	kWh	5,288,437,000
All Other Retail Classes	kWh	3,099,359,000

Billing Factors 8/		**Proposed 1/1/2020**
Large Power	$/kW - month	(0.35)
	¢/kWh	(0.040)
All Other Retail Classes	¢/kWh	0.190

		Curent Factor	Proposed	Change
Large Power	($/kW - month)	(0.33)	(0.35)	(0.02)
	(¢/kWh)	(0.037)	(0.040)	(0.003)
All Other Classes	(¢/kWh)	(0.096)	0.190	0.286

Notes:
1/ Refer to Exhibit B-1, page 2.
2/ Refer to Exhibit B-1, page 5, lines C24, C26, C27.
3/ 2020 Budget.
4/ The LP rate design is a demand rate adder ($/kW-month) and an energy adder (¢/kWh). The LP allocated costs are split between demand and energy on the 2017 base rate demand and energy revenue split of approximately 56% demand and 44% energy per results of MP's 2017 MPUC rate case (Docket No. E015/GR-16-664). All other retail classes will have an energy adder (¢/kWh).

Minnesota Power
Renewable Resources Rider: 2020 Factor Filing
Tracker Summary

	Allocators		
2017 Ending Tracker (Over)/Under Collection 1/			
MN Jurisdictional Tracker		$	(4,011,273)
Large Power		$	(2,344,353)
All Other Retail Classes		$	(1,666,920)
2017 PTC True-Up 2/	Allocators		
MN Jurisdictional & Class Revenue Requirements	100.00%	$	(2,953,880)
Large Power	61.68%	$	(1,821,833)
All Other Retail Classes	38.32%	$	(1,132,047)
2017 Year End			
MN Jurisdictional & Class Revenue Requirements		$	(6,965,153)
Large Power		$	(4,166,185)
All Other Retail Classes		$	(2,798,968)
2018 Net Revenue Requirements 3/			
MN Jurisdictional & Class Revenue Requirements		$	5,912,314
Large Power		$	3,656,931
All Other Retail Classes		$	2,255,383
2018 Rider Cash Collections 4/			
MN Jurisdiction		$	(6,697,737)
Large Power		$	(9,540,829)
All Other Classes		$	2,843,092
2018 Year-End Tracker Balance (Over)/Under Collection			
MN Jurisdiction		$	(7,750,576)
Large Power		$	(10,050,083)
All Other Classes		$	2,299,507
2019 Projected Net Revenue Requirements 5/			
MN Jurisdictional & Class Revenue Requirements			1,254,667.997
Large Power			773,830.914
All Other Retail Classes		$	480,837
2019 Projected Rider Cash Collections 6/			
MN Jurisdiction		$	7,634,559
Large Power		$	4,525,087
All Other Classes		$	3,109,472
2019 Projected Year-End Tracker Balance (Over)/Under Collection			
MN Jurisdiction		$	1,138,651
Large Power		$	(4,751,165)
All Other Classes		$	5,889,816

Notes:
1/ 2018 Renewable Resources Rider, Docket E015/M-18-375, Exhibit B-1, page 1.
2/ 2018 Renewable Resources Rider, Docket E015/M-18-375, Exhibit B-2, page 8.
3/ Includes LGIA Revenue Credit and PTC True-up, Refer to Exhibit B-1, page 3, line D1
4/ Refer to Exhibit B-1, page 3, line E1.
5/ Includes LGIA Revenue Credit and PTC True-up, Refer to Exhibit B-1, page 4, line D1
6/ Refer to Exhibit B-1, page 4, line E1.

2018 RRR Tracker: Total Sum All Projects

Section	Line	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total Year 2018
A	**Book Basis of Property**														
	0 CWIP		414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	-	-	-	-
	1 Plant in Service		6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,536,723	6,536,723	6,536,723	6,536,723
	2 Total Accumulated Depreciation		16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	114,350	125,956	137,562	137,562
	3 Net Plant		6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,422,373	6,410,767	6,399,161	6,399,161
	4 Total Depreciation		10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	11,230	11,606	11,606	132,134
	5 Book Depreciation Rate (35 year book life)														
B	**Tax Basis of Property**														
	1 Investment Tax Credit (30%)		-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Reduction to Book and Tax Basis (ITC x 50%)		-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes		-	-	-	-	-	-	-	-	-	414,677	-	-	414,677
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes		6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,536,723	6,536,723	6,536,723	6,536,723
	5 Book Style Depreciation for Deferred Taxes		10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	11,230	11,606	11,606	132,134
	6 Accum Book Style Depreciation for Deferred Taxes		16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	114,350	125,956	137,562	137,562
	7 Accumulated Tax Depreciation		3,194,226	3,212,641	3,231,055	3,249,470	3,267,884	3,286,299	3,304,714	3,323,128	3,341,543	3,359,958	3,378,372	3,396,787	3,396,787
	8 Net Plant for Tax		2,927,820	2,909,406	2,890,991	2,872,576	2,854,162	2,835,747	2,817,333	2,798,918	2,780,503	3,176,766	3,158,351	3,139,936	3,139,936
	9 Bonus Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Tax Depreciation (including bonus)		18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	220,975
	11 Tax Book Difference		7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,184	6,809	6,809	88,841
	12 Income Tax Rate		28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference		2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,065	1,957	1,957	25,535
	14 Total Accumulated Deferred Income Tax Liability		913,405	915,578	917,750	919,923	922,096	924,269	926,442	928,615	930,788	932,853	934,810	936,766	936,766
	15 Deferred Tax Expense debit / (Credit)		2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,065	1,957	1,957	25,535
C	**Revenue Requirements**														
	1 Net Plant		6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,422,373	6,410,767	6,399,161	6,399,161
	2 Less: ADITL - Def Taxes		(913,405)	(915,578)	(917,750)	(919,923)	(922,096)	(924,269)	(926,442)	(928,615)	(930,788)	(932,853)	(934,810)	(936,766)	(936,766)
	3 Plus: ADITA - NOL		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: ADITA - PTC		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base		5,192,360	5,179,332	5,166,304	5,153,277	5,140,249	5,127,222	5,114,194	5,101,167	5,088,139	5,489,521	5,475,958	5,462,395	5,462,395
	5 Average Rate Base		5,198,873	5,185,846	5,172,818	5,159,791	5,146,763	5,133,735	5,120,708	5,107,680	5,094,653	5,288,830	5,482,739	5,469,176	5,469,176
	6 Current Return on CWIP		3,613	3,613	3,613	3,135	3,135	3,135	3,135	3,135	3,135	1,567	-	-	31,215
	7 Return on Average Rate Base														
	8 After Tax Return on Equity		24,435	24,373	24,312	21,402	21,348	21,294	21,240	21,186	21,132	21,938	22,742	22,686	268,089
	9 Income Tax Component		9,856	9,831	9,806	8,633	8,611	8,589	8,567	8,546	8,524	8,849	9,173	9,150	108,135
	10 Interest Expense Component		11,004	10,977	10,949	8,971	8,949	8,926	8,903	8,881	8,858	9,196	9,533	9,509	114,655
	11 Total Return on Average Rate Base		45,295	45,181	45,068	39,006	38,908	38,809	38,711	38,612	38,514	39,982	41,448	41,345	490,878
	12 Operation & Maintenance Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense		10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	11,230	11,606	11,606	132,134
	14 Property Tax		19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	239,646
	15 ITC		-	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements		79,733	79,619	79,506	72,966	72,868	72,769	72,671	72,572	72,474	72,750	73,024	72,921	893,873
	17 Jurisdictional Allocator /1		0.82017	0.82017	0.82017	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	
	18 Jurisdictional Revenue Requirements		65,394	65,301	65,208	61,554	61,471	61,388	61,305	61,222	61,139	61,372	61,603	61,517	748,475
	19 Jurisdictional Base Rate Revenue Credit /2		(202)	(202)	(202)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(2,360)
	20 Jurisdictional Bison 6 LGIA Credit		-	(90,973)	(90,973)	(84,593)	(84,593)	(84,593)	(84,593)	(84,593)	(84,593)	(84,593)	(84,593)	(84,593)	(943,281)
	21 Jurisdictional PTC True-up		312,529	(570,510)	1,496,730	585,997	1,189,814	777,785	582,367	267,547	(8,670)	743,955	1,255,615	(523,680)	6,109,480
	22 Net Jurisdictional Revenue Requirements		377,721	(596,383)	1,470,763	562,763	1,166,498	754,386	558,885	243,981	(32,319)	720,539	1,232,431	(546,951)	5,912,314
	23 Large Power Class Allocation 1/		0.62510	0.62510	0.62510	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	
	24 Large Power Class Revenue Requirements		236,114	(372,800)	919,377	347,091	719,451	465,276	344,699	150,478	(19,933)	444,401	760,116	(337,338)	3,656,931
	25 All Other Class Revenue Requirements /3		141,607	(223,583)	551,386	215,673	447,047	289,110	214,186	93,503	(12,386)	276,138	472,315	(209,613)	2,255,383
D	**Monthly Entry**														
	1 MN Jurisdictional Revenue Requirements		**377,721**	**(596,383)**	**1,470,763**	**562,763**	**1,166,498**	**754,386**	**558,885**	**243,981**	**(32,319)**	**720,539**	**1,232,431**	**(546,951)**	**5,912,314**
	2 Monthly Entry Needed		377,721	(596,383)	1,470,763	562,763	1,166,498	754,386	558,885	243,981	(32,319)	720,539	1,232,431	(546,951)	5,912,314
	3 Cumulative YTD		377,721	(218,662)	1,252,101	1,814,864	2,981,362	3,735,748	4,294,632	4,538,614	4,506,295	5,226,834	6,459,265	5,912,314	5,912,314
E	**Tracker**														
	1 Cash Collections		(1,400,461)	(1,341,855)	(1,441,570)	(1,350,797)	(1,401,892)	(1,414,277)	(1,435,548)	595,114	617,338	607,467	620,394	648,350	(6,697,737)
	2 Monthly (Over)/Under collection		(1,022,740)	(1,938,238)	29,193	(788,034)	(235,395)	(659,891)	(876,663)	839,095	585,019	1,328,006	1,852,825	101,399	(785,423)
	3 Cumulative (Over)/Under Balance	(6,965,153)	(7,987,893)	(9,926,131)	(9,896,938)	(10,684,972)	(10,920,367)	(11,580,258)	(12,456,921)	(11,617,825)	(11,032,806)	(9,704,800)	(7,851,975)	(7,750,576)	(7,750,576)

Notes:
1/ Refer to Exhibit B-5, page 1.
2/ Refer to Exhibit B-2, page 6.
3/ Line C22 - Line C24.

2019 RRR Projected Tracker: Total Sum All Projects

Section	Line	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total Year 2019
A	**Book Basis of Property**														
	0 CWIP		-	-	-	-	-	-	-	-	-	-	-	-	-
	1 Plant in Service		6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723
	2 Total Accumulated Depreciation		149,168	160,774	172,379	183,985	195,591	207,197	218,803	230,409	242,015	253,621	265,227	276,833	276,833
	3 Net Plant		6,387,556	6,375,950	6,364,344	6,352,738	6,341,132	6,329,526	6,317,920	6,306,314	6,294,708	6,283,102	6,271,496	6,259,890	6,259,890
	4 Total Depreciation		11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	139,271
	5 Book Depreciation Rate (35 year book life)														
B	**Tax Basis of Property**														
	1 Investment Tax Credit (30%)		-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Reduction to Book and Tax Basis (ITC x 50%)		-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes		6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723	6,536,723
	5 Book Style Depreciation for Deferred Taxes		11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	139,271
	6 Accum Book Style Depreciation for Deferred Taxes		149,168	160,774	172,379	183,985	195,591	207,197	218,803	230,409	242,015	253,621	265,227	276,833	276,833
	7 Accumulated Tax Depreciation		3,413,819	3,430,851	3,447,883	3,464,915	3,481,947	3,498,979	3,516,011	3,533,043	3,550,075	3,567,107	3,584,139	3,601,171	3,601,171
	8 Net Plant for Tax		3,122,904	3,105,872	3,088,840	3,071,808	3,054,776	3,037,744	3,020,712	3,003,680	2,986,648	2,969,616	2,952,584	2,935,552	2,935,552
	9 Bonus Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Tax Depreciation (including bonus)		17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	204,385
	11 Tax Book Difference		5,426	5,426	5,426	5,426	5,426	5,426	5,426	5,426	5,426	5,426	5,426	5,426	65,113
	12 Income Tax Rate		28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference		1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	18,715
	14 Total Accumulated Deferred Income Tax Liability		938,326	939,886	941,445	943,005	944,564	946,124	947,683	949,243	950,803	952,362	953,922	955,481	955,481
	15 Deferred Tax Expense debit / (Credit)		1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	1,560	18,715
C	**Revenue Requirements**														
	1 Net Plant		6,387,556	6,375,950	6,364,344	6,352,738	6,341,132	6,329,526	6,317,920	6,306,314	6,294,708	6,283,102	6,271,496	6,259,890	6,259,890
	2 Less: ADITL - Def Taxes		(938,326)	(939,886)	(941,445)	(943,005)	(944,564)	(946,124)	(947,683)	(949,243)	(950,803)	(952,362)	(953,922)	(955,481)	(955,481)
	3 Plus: ADITA - NOL		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: ADITA - PTC		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base		5,449,230	5,436,064	5,422,899	5,409,733	5,396,568	5,383,402	5,370,237	5,357,071	5,343,906	5,330,740	5,317,575	5,304,409	5,304,409
	5 Average Rate Base		5,455,812	5,442,647	5,429,481	5,416,316	5,403,150	5,389,985	5,376,819	5,363,654	5,350,488	5,337,323	5,324,157	5,310,992	5,310,992
	6 Current Return on CWIP		-	-	-	-	-	-	-	-	-	-	-	-	-
	7 Return on Average Rate Base														
	8 After Tax Return on Equity		22,630	22,576	22,521	22,466	22,412	22,357	22,303	22,248	22,193	22,139	22,084	22,029	267,958
	9 Income Tax Component		9,128	9,106	9,084	9,062	9,040	9,018	8,996	8,974	8,952	8,930	8,908	8,886	108,083
	10 Interest Expense Component		9,486	9,463	9,440	9,417	9,394	9,371	9,348	9,326	9,303	9,280	9,257	9,234	112,319
	11 Total Return on Average Rate Base		41,244	41,145	41,045	40,945	40,846	40,746	40,647	40,547	40,448	40,348	40,249	40,149	488,360
	12 Operation & Maintenance Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense		11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	11,606	139,271
	14 Property Tax		19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	19,971	239,646
	15 ITC		-	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements		72,820	72,721	72,621	72,522	72,422	72,323	72,223	72,124	72,024	71,925	71,825	71,726	867,277
	17 Jurisdictional Allocator /1		0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	0.84360	
	18 Jurisdictional Revenue Requirements		61,431	61,347	61,263	61,179	61,095	61,012	60,928	60,844	60,760	60,676	60,592	60,508	731,635
	19 Jurisdictional Base Rate Revenue Credit /2		(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(2,339)
	20 Jurisdictional Bison 6 LGIA Credit		(84,593)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(74,376)	(902,729)
	21 Jurisdictional PTC True-up		1,139,954	550,068	208,024	999,962	487,272	(163,007)	(279,682)	(719,732)	(545,197)	387,536	110,553	(729,863)	1,445,888
	22 Jurisdictional Oconto Recs		(1,567)	(1,404)	(1,315)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(17,786)
	23 Net Jurisdictional Revenue Requirements		1,115,031	535,440	193,402	985,070	472,296	(178,066)	(294,826)	(734,959)	(560,508)	372,141	95,074	(745,426)	1,254,668
	24 Large Power Class Allocation 1/		0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	
	25 Large Power Class Revenue Requirements		687,708	330,239	119,283	607,554	291,294	(109,824)	(181,837)	(453,295)	(345,700)	229,522	58,638	(459,750)	773,831
	26 All Other Class Revenue Requirements /3		427,323	205,201	74,119	377,517	181,002	(68,242)	(112,989)	(281,665)	(214,808)	142,619	36,436	(285,676)	480,837
D	**Monthly Entry**														
	1 MN Jurisdictional Revenue Requirements		**1,115,031**	**535,440**	**193,402**	**985,070**	**472,296**	**(178,066)**	**(294,826)**	**(734,959)**	**(560,508)**	**372,141**	**95,074**	**(745,426)**	**1,254,668**
	2 Monthly Entry Needed		1,115,031	535,440	193,402	985,070	472,296	(178,066)	(294,826)	(734,959)	(560,508)	372,141	95,074	(745,426)	1,254,668
	3 Cumulative YTD		1,115,031	1,650,471	1,843,872	2,828,943	3,301,239	3,123,173	2,828,347	2,093,388	1,532,879	1,905,020	2,000,094	1,254,668	1,254,668
E	**Projected 2019 Tracker**														
	1 Cash Collections 4/		662,890	653,971	655,403	614,216	596,079	636,000	636,000	636,000	636,000	636,000	636,000	636,000	7,634,559
	2 Monthly (Over)/Under collection		1,777,921	1,189,411	848,804	1,599,287	1,068,375	457,934	341,174	(98,959)	75,492	1,008,141	731,074	(109,426)	8,889,227
	3 Cumulative (Over)/Under Balance	(7,750,576)	(5,972,655)	(4,783,244)	(3,934,440)	(2,335,153)	(1,266,778)	(808,844)	(467,670)	(566,629)	(491,138)	517,003	1,248,077	1,138,651	1,138,651

Notes:
1/ Refer to Exhibit B-5, page 1.
2/ Refer to Exhibit B-2, page 6.
3/ Line C20 - Line C22.

2020 RRR Projected Tracker: Total Sum All Projects

Section	Line	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total Year 2020
A	**Book Basis of Property**														
	0 CWIP		-	-	-	-	-	-	-	-	-	-	-	-	-
	1 Plant in Service		-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Total Accumulated Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Net Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Total Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Depreciation Rate (35 year book life)														
B	**Tax Basis of Property**														
	1 Investment Tax Credit (30%)		-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Reduction to Book and Tax Basis (ITC x 50%)		-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
	5 Book Style Depreciation for Deferred Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Accum Book Style Depreciation for Deferred Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
	7 Accumulated Tax Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Net Plant for Tax		-	-	-	-	-	-	-	-	-	-	-	-	-
	9 Bonus Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Total Tax Depreciation (including bonus)		-	-	-	-	-	-	-	-	-	-	-	-	-
	11 Tax Book Difference		-	-	-	-	-	-	-	-	-	-	-	-	-
	12 Income Tax Rate		28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference		-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Total Accumulated Deferred Income Tax Liability		-	-	-	-	-	-	-	-	-	-	-	-	-
	15 Deferred Tax Expense debit / (Credit)		-	-	-	-	-	-	-	-	-	-	-	-	-
C	**Revenue Requirements**														
	1 Net Plant		-	-	-	-	-	-	-	-	-	-	-	-	-
	2 Less: ADITL - Def Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
	3 Plus: ADITA - NOL		-	-	-	-	-	-	-	-	-	-	-	-	-
	4 Plus: ADITA - PTC		-	-	-	-	-	-	-	-	-	-	-	-	-
	5 Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-
	6 Average Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-
	7 Current Return on CWIP		-	-	-	-	-	-	-	-	-	-	-	-	-
	8 Return on Average Rate Base														
	9 After Tax Return on Equity		-	-	-	-	-	-	-	-	-	-	-	-	-
	10 Income Tax Component		-	-	-	-	-	-	-	-	-	-	-	-	-
	11 Interest Expense Component		-	-	-	-	-	-	-	-	-	-	-	-	-
	12 Total Return on Average Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-
	13 Operation & Maintenance Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	14 Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	15 Property Tax		-	-	-	-	-	-	-	-	-	-	-	-	-
	16 ITC		-	-	-	-	-	-	-	-	-	-	-	-	-
	17 Revenue Requirements		-	-	-	-	-	-	-	-	-	-	-	-	-
	18 Jurisdictional Allocator /1		-	-	-	-	-	-	-	-	-	-	-	-	
	19 Jurisdictional Revenue Requirements		-	-	-	-	-	-	-	-	-	-	-	-	-
	20 Jurisdictional Base Rate Revenue Credit /2		-	-	-	-	-	-	-	-	-	-	-	-	-
	21 Jurisdictional Bison 6 LGIA Credit		-	-	-	-	-	-	-	-	-	-	-	-	-
	22 Jurisdictional PTC True-up		-	-	-	-	-	-	-	-	-	-	-	-	-
	23 Jurisdictional Oconto Recs		(1,310)	(1,226)	(1,310)	(1,268)	(1,310)	(1,268)	(1,310)	(1,310)	(1,268)	(1,310)	(1,268)	(1,310)	(15,470)
	24 Net Jurisdictional Revenue Requirements		(1,310)	(1,226)	(1,310)	(1,268)	(1,310)	(1,268)	(1,310)	(1,310)	(1,268)	(1,310)	(1,268)	(1,310)	(15,470)
	25 Large Power Class Allocation 1/		0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	0.61676	
	26 Large Power Class Revenue Requirements		(808)	(756)	(808)	(782)	(808)	(782)	(808)	(808)	(782)	(808)	(782)	(808)	(9,542)
	27 All Other Class Revenue Requirements /3		(502)	(470)	(502)	(486)	(502)	(486)	(502)	(502)	(486)	(502)	(486)	(502)	(5,929)
D	**Monthly Entry**														
	1 MN Jurisdictional Revenue Requirements		**(1,310)**	**(1,226)**	**(1,310)**	**(1,268)**	**(1,310)**	**(1,268)**	**(1,310)**	**(1,310)**	**(1,268)**	**(1,310)**	**(1,268)**	**(1,310)**	**(15,470)**
	2 Monthly Entry Needed		(1,310)	(1,226)	(1,310)	(1,268)	(1,310)	(1,268)	(1,310)	(1,310)	(1,268)	(1,310)	(1,268)	(1,310)	(15,470)
	3 Cumulative YTD		(1,310)	(2,536)	(3,846)	(5,115)	(6,425)	(7,693)	(9,003)	(10,314)	(11,582)	(12,892)	(14,160)	(15,470)	(15,470)

Notes:
1/ Refer to Exhibit B-5, page 1.
2/ Refer to Exhibit B-2, page 6.
3/ Line C20 - Line C22.

THM Replace/Refurbish Dam 6
Project ID # 106069
In Service 10/11/2018

Section	Line	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
A	**Book Basis of Property**												
	0 CWIP	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677			
	1 Plant in Service										414,677	414,677	414,677
	2 Total Accumulated Depreciation	-	-	-	-	-	-	-	-	-	376	1,127	1,878
	3 Net Plant	-	-	-	-	-	-	-	-	-	414,301	413,550	412,799
	4 Total Depreciation	-	-	-	-	-	-	-	-	-	376	751	751
	5 Book Depreciation Rate 1/										0.18%	0.18%	0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) 2/												-
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	414,677	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	414,677	414,677	414,677
	5 Book Style Depreciation for Deferred Taxes	-	-	-	-	-	-	-	-	-	376	751	751
	6 Accum Book Style Depreciation for Deferred Taxes	-	-	-	-	-	-	-	-	-	376	1,127	1,878
	7 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	8 Net Plant for Tax	-	-	-	-	-	-	-	-	-	414,677	414,677	414,677
	9 Bonus Depreciation												
	10 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-
	11 Tax Book Difference	-	-	-	-	-	-	-	-	-	(376)	(751)	(751)
	12 Income Tax Rate 3/	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference	-	-	-	-	-	-	-	-	-	(108)	(216)	(216)
	14 Total Accumulated Deferred Income Tax Liability	-	-	-	-	-	-	-	-	-	(108)	(324)	(540)
	15 Deferred Tax Expense debit / (Credit)	-	-	-	-	-	-	-	-	-	(108)	(216)	(216)
C	**Revenue Requirements**												
	1 Net Plant	-	-	-	-	-	-	-	-	-	414,301	413,550	412,799
	2 Less: ADITL - Def Taxes	-	-	-	-	-	-	-	-	-	108	324	540
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	-	-	-	-	-	-	-	-	-	414,409	413,874	413,339
	5 Average Rate Base	-	-	-	-	-	-	-	-	-	207,205	414,142	413,606
	6 Current Return on CWIP 4/	3,613	3,613	3,613	3,135	3,135	3,135	3,135	3,135	3,135	1,567		
	7 Return on Average Rate Base 4/												
	8 After Tax Return on Equity	-	-	-	-	-	-	-	-	-	859	1,718	1,716
	9 Income Tax Component	-	-	-	-	-	-	-	-	-	347	693	692
	10 Interest Expense Component	-	-	-	-	-	-	-	-	-	360	720	719
	11 Total Return on Average Rate Base	-	-	-	-	-	-	-	-	-	1,566	3,131	3,127
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	-	-	-	-	-	-	-	-	-	376	751	751
	14 Property Tax	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	4,996	4,996	4,996	4,518	4,518	4,518	4,518	4,518	4,518	4,892	5,265	5,261

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664 starting 12/1/2018. Refer to Exhibit B-4.
4/ Refer to Exhibit B-4.

THM Replace/Refurbish Dam 6
Project ID # 106069
In Service 10/11/2018

Section	Line	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
A	**Book Basis of Property**												
	0 CWIP												
	1 Plant in Service	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677
	2 Total Accumulated Depreciation	2,629	3,381	4,132	4,883	5,634	6,385	7,137	7,888	8,639	9,390	10,142	10,893
	3 Net Plant	412,048	411,296	410,545	409,794	409,043	408,292	407,540	406,789	406,038	405,287	404,535	403,784
	4 Total Depreciation	751	751	751	751	751	751	751	751	751	751	751	751
	5 Book Depreciation Rate 1/	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) 2/												
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677
	5 Book Style Depreciation for Deferred Taxes	751	751	751	751	751	751	751	751	751	751	751	751
	6 Accum Book Style Depreciation for Deferred Taxes	2,629	3,381	4,132	4,883	5,634	6,385	7,137	7,888	8,639	9,390	10,142	10,893
	7 Accumulated Tax Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
	8 Net Plant for Tax	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677
	9 Bonus Depreciation												
	10 Total Tax Depreciation (including bonus)	-	-	-	-	-	-	-	-	-	-	-	-
	11 Tax Book Difference	(751)	(751)	(751)	(751)	(751)	(751)	(751)	(751)	(751)	(751)	(751)	(751)
	12 Income Tax Rate 3/	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)
	14 Total Accumulated Deferred Income Tax Liability	(756)	(972)	(1,188)	(1,403)	(1,619)	(1,835)	(2,051)	(2,267)	(2,483)	(2,699)	(2,915)	(3,131)
	15 Deferred Tax Expense debit / (Credit)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)	(216)
C	**Revenue Requirements**												
	1 Net Plant	412,048	411,296	410,545	409,794	409,043	408,292	407,540	406,789	406,038	405,287	404,535	403,784
	2 Less: ADITL - Def Taxes	756	972	1,188	1,403	1,619	1,835	2,051	2,267	2,483	2,699	2,915	3,131
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	412,803	412,268	411,733	411,197	410,662	410,127	409,592	409,056	408,521	407,986	407,450	406,915
	5 Average Rate Base	413,071	412,536	412,000	411,465	410,930	410,394	409,859	409,324	408,789	408,253	407,718	407,183
	6 Current Return on CWIP 4/												
	7 Return on Average Rate Base 4/												
	8 After Tax Return on Equity	1,713	1,711	1,709	1,707	1,704	1,702	1,700	1,698	1,696	1,693	1,691	1,689
	9 Income Tax Component	691	690	689	688	688	687	686	685	684	683	682	681
	10 Interest Expense Component	718	717	716	715	714	714	713	712	711	710	709	708
	11 Total Return on Average Rate Base	3,123	3,119	3,115	3,111	3,106	3,102	3,098	3,094	3,090	3,086	3,082	3,078
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	751	751	751	751	751	751	751	751	751	751	751	751
	14 Property Tax	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383	1,383
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	5,257	5,253	5,249	5,245	5,241	5,236	5,232	5,228	5,224	5,220	5,216	5,212

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664 starting 12/1/2018. Refer to Exhibit B-4.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664. Refer to Exhibit B-4.

THM Spill Capacity
Project ID # 106794
In Service 12/31/2017

Section	Line	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
A	**Book Basis of Property**												
	0 CWIP												
	1 Plant in Service	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046
	2 Total Accumulated Depreciation	16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	113,974	124,829	135,684
	3 Net Plant	6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,008,072	5,997,217	5,986,363
	4 Total Depreciation	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	5 Book Depreciation Rate 1/	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) /2												
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046
	5 Book Style Depreciation for Deferred Taxes	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	6 Accum Book Style Depreciation for Deferred Taxes	16,282	27,137	37,991	48,846	59,701	70,555	81,410	92,265	103,120	113,974	124,829	135,684
	7 Accumulated Tax Depreciation	3,194,226	3,212,641	3,231,055	3,249,470	3,267,884	3,286,299	3,304,714	3,323,128	3,341,543	3,359,958	3,378,372	3,396,787
	8 Net Plant for Tax	2,927,820	2,909,406	2,890,991	2,872,576	2,854,162	2,835,747	2,817,333	2,798,918	2,780,503	2,762,089	2,743,674	2,725,259
	9 Bonus Depreciation 50% in 2017												
	10 Total Tax Depreciation (including bonus)	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415	18,415
	11 Tax Book Difference	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560	7,560
	12 Income Tax Rate 3/	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173
	14 Total Accumulated Deferred Income Tax Liability	913,405	915,578	917,750	919,923	922,096	924,269	926,442	928,615	930,788	932,961	935,133	937,306
	15 Deferred Tax Expense debit / (Credit)	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173	2,173
C	**Revenue Requirements - MP Regulated NOL**												
	1 Net Plant	6,105,764	6,094,909	6,084,055	6,073,200	6,062,345	6,051,491	6,040,636	6,029,781	6,018,927	6,008,072	5,997,217	5,986,363
	2 Less: ADITL - Def Taxes	(913,405)	(915,578)	(917,750)	(919,923)	(922,096)	(924,269)	(926,442)	(928,615)	(930,788)	(932,961)	(935,133)	(937,306)
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	5,192,360	5,179,332	5,166,304	5,153,277	5,140,249	5,127,222	5,114,194	5,101,167	5,088,139	5,075,111	5,062,084	5,049,056
	5 Average Rate Base	5,198,873	5,185,846	5,172,818	5,159,791	5,146,763	5,133,735	5,120,708	5,107,680	5,094,653	5,081,625	5,068,598	5,055,570
	6 Current Return on CWIP 4/												
	7 Return on Average Rate Base 4/												
	8 After Tax Return on Equity	24,435	24,373	24,312	21,402	21,348	21,294	21,240	21,186	21,132	21,078	21,024	20,970
	9 Income Tax Component	9,856	9,831	9,806	8,633	8,611	8,589	8,567	8,546	8,524	8,502	8,480	8,458
	10 Interest Expense Component	11,004	10,977	10,949	8,971	8,949	8,926	8,903	8,881	8,858	8,835	8,813	8,790
	11 Total Return on Average Rate Base	45,295	45,181	45,068	39,006	38,908	38,809	38,711	38,612	38,514	38,415	38,317	38,218
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	14 Property Tax	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	74,737	74,624	74,510	68,449	68,350	68,252	68,153	68,055	67,956	67,858	67,759	67,661

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
3/ Minnesota Composite Income Tax Rate.
4/ Refer to Exhibit B-4.

THM Spill Capacity
Project ID # 106794
In Service 12/31/2017

Section	Line	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
A	**Book Basis of Property**												
	0 CWIP												
	1 Plant in Service	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046
	2 Total Accumulated Depreciation	146,538	157,393	168,248	179,102	189,957	200,812	211,666	222,521	233,376	244,231	255,085	265,940
	3 Net Plant	5,975,508	5,964,653	5,953,798	5,942,944	5,932,089	5,921,234	5,910,380	5,899,525	5,888,670	5,877,816	5,866,961	5,856,106
	4 Total Depreciation	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	5 Book Depreciation Rate 1/	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%	0.18%
B	**Tax Basis of Property**												
	1 Investment Tax Credit (30%) /2												
	2 Reduction to Book and Tax Basis (ITC x 50%)	-	-	-	-	-	-	-	-	-	-	-	-
	3 Adjusted Book and Tax Basis for Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
	4 Cum Adjusted Book and Tax Basis for Deferred Taxes	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046	6,122,046
	5 Book Style Depreciation for Deferred Taxes	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	6 Accum Book Style Depreciation for Deferred Taxes	146,538	157,393	168,248	179,102	189,957	200,812	211,666	222,521	233,376	244,231	255,085	265,940
	7 Accumulated Tax Depreciation	3,413,819	3,430,851	3,447,883	3,464,915	3,481,947	3,498,979	3,516,011	3,533,043	3,550,075	3,567,107	3,584,139	3,601,171
	8 Net Plant for Tax	2,708,227	2,691,195	2,674,163	2,657,131	2,640,099	2,623,067	2,606,035	2,589,003	2,571,971	2,554,939	2,537,907	2,520,875
	9 Bonus Depreciation 50% in 2017												
	10 Total Tax Depreciation (including bonus)	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032	17,032
	11 Tax Book Difference	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177	6,177
	12 Income Tax Rate 3/	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%	28.742%
	13 Deferred Income Tax on Timing Difference	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
	14 Total Accumulated Deferred Income Tax Liability	939,082	940,857	942,633	944,408	946,184	947,959	949,735	951,510	953,286	955,061	956,837	958,612
	15 Deferred Tax Expense debit / (Credit)	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775	1,775
C	**Revenue Requirements - MP Regulated NOL**												
	1 Net Plant	5,975,508	5,964,653	5,953,798	5,942,944	5,932,089	5,921,234	5,910,380	5,899,525	5,888,670	5,877,816	5,866,961	5,856,106
	2 Less: ADITL - Def Taxes	(939,082)	(940,857)	(942,633)	(944,408)	(946,184)	(947,959)	(949,735)	(951,510)	(953,286)	(955,061)	(956,837)	(958,612)
	3 Plus: ADITA - NOL												
	4 Plus: ADITA - PTC	-	-	-	-	-	-	-	-	-	-	-	-
	4 Rate Base	5,036,426	5,023,796	5,011,166	4,998,536	4,985,905	4,973,275	4,960,645	4,948,015	4,935,385	4,922,754	4,910,124	4,897,494
	5 Average Rate Base	5,042,741	5,030,111	5,017,481	5,004,851	4,992,220	4,979,590	4,966,960	4,954,330	4,941,700	4,929,070	4,916,439	4,903,809
	6 Current Return on CWIP 4/												
	7 Return on Average Rate Base 4/												
	8 After Tax Return on Equity	20,917	20,864	20,812	20,760	20,707	20,655	20,602	20,550	20,498	20,445	20,393	20,341
	9 Income Tax Component	8,437	8,416	8,395	8,374	8,352	8,331	8,310	8,289	8,268	8,247	8,226	8,204
	10 Interest Expense Component	8,768	8,746	8,724	8,702	8,680	8,658	8,636	8,614	8,592	8,570	8,548	8,526
	11 Total Return on Average Rate Base	38,121	38,026	37,930	37,835	37,739	37,644	37,548	37,453	37,358	37,262	37,167	37,071
	12 Operation & Maintenance Expense	-	-	-	-	-	-	-	-	-	-	-	-
	13 Depreciation Expense	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855	10,855
	14 Property Tax	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588	18,588
	15 ITC	-	-	-	-	-	-	-	-	-	-	-	-
	16 Revenue Requirements	67,564	67,468	67,373	67,277	67,182	67,086	66,991	66,895	66,800	66,704	66,609	66,513

Notes:
1/ Remaining life is 50 years beginning 1/1/2014.
2/ ITC limit reached on previous Thomson projects so not applied here.
3/ Minnesota Composite Income Tax Rate.
4/ Pre-tax rate of return from 2016 MPUC rate case, Docket No. E-015/GR-16-664. Refer to Exhibit B-4.

Thomson Base Rate Revenue Credit for 12/1/2017 and forward

Property Retirements in Base Rates

Section	Line		2009	Base Rates 2010		
A		**Book Basis of Retired Property**				
	1	Plant in Service	121,484	121,484		
	2	Total Accumulated Depreciation	98,145	99,718		
	3	Net Plant	23,339	21,766		
	4	Depreciation Expense		1,573		
B		**Tax Basis of Retired Property**				
	1	Plant in Service	121,484	121,484		
	2	Accumulated Depreciation	121,484	121,484		
	3	Net Plant	-	-		
	4	Total Tax Depreciation		-		
	5	Tax Book Difference	23,339	21,766		
	6	Income Tax Rate 1/	41.37%	41.37%		
	7	Accumulated Deferred Income Tax Liability	9,655	9,004		
	8	Deferred Tax Expense debit / (Credit)		(651)		
C		**Revenue Requirements in Base Rates**				
	1	Net Plant	23,339	21,766		
	2	Less: ADITL - Def Taxes	(9,655)	(9,004)		
	3	Rate Base	13,683	12,761		
	4	Average Rate Base		13,222		
				Starting 12/1/2017	Starting 1/1/2018	Starting 4/1/2018
	5	Return on Average Rate Base 2/				
	6	After Tax Return on Equity		745	746	658
	7	Income Tax Component		526	301	265
	8	Interest Expense Component		336	336	276
	9	Total Return on Average Rate Base		1,607	1,382	1,199
	10	Operation & Maintenance Expense Associated with Retired Plant		-	-	-
	11	Depreciation Expense		1,573	1,573	1,573
	12	Property Tax		-	-	-
	13	Revenue Requirements in Base Rates Associated with Retired Property		3,180	2,956	2,773
	14	Monthly Credit for Revenue Requirements in Base Rates 3/		(265)	(246)	(231)
	15	MN Jurisdictional Allocator 4/		0.82017	0.82017	0.84360
	16	MN Jurisdictional Revenue Credit		(217)	(202)	(195)

Notes:

1/ Minnesota Composite Income Tax Rate.

2/ Refer to Exhibit B-4 rate of return components.

3/ This monthly revenue requirement credit is needed beginning with the retirement in 12/2017 and until the retirements and the project #106794 are incorporated into base rates in a subsequent rate case.

4/ Refer to Exhibit B-5.

Minnesota Power

Renewable Resources Rider: 2020 RRR Factor Filing

Base Rate Revenue Credit for Bison 6 LGIA Transaction /1

Section	Line	2016	Base Rates 2017	
A	**Book Basis of Bison 6 LGIA Related Property**			
	1 Plant in Service	52,073,893	52,073,893	
	2 Total Accumulated Depreciation	5,708,846	7,424,287	
	3 Net Plant	46,365,047	44,649,606	
	4 Depreciation Expense		1,715,440	
B	**Tax Basis**			
	1 Plant in Service	52,073,893	52,073,893	
	2 Accumulated Depreciation	36,586,965	37,960,242	
	3 Net Plant	15,486,928	14,113,651	
	4 Total Tax Depreciation		1,373,277	
	5 Tax Book Difference	30,878,119	30,535,955	
	6 Income Tax Rate	28.742%	28.742%	
	7 Accumulated Deferred Income Tax Liability	8,874,989	8,776,644	
	8 Deferred Tax Expense debit / (Credit)		(98,345)	
C	**Revenue Requirements in Base Rates**			
	1 Net Plant	46,365,047	44,649,606	
	2 Less: ADITL - Def Taxes	(8,874,989)	(8,776,644)	
	3 Rate Base	37,490,058	35,872,962	
	4 Average Rate Base		36,681,510	
	5 Return on Average Rate Base /2		Starting 2/1/18	Starting 4/1/18
	6 After Tax Return on Equity		2,068,837	1,825,815.05
	7 Income Tax Component		834,468	736,454.68
	8 Interest Expense Component		931,710	765,323.02
	9 Total Return on Average Rate Base		3,835,015	3,327,593
	10 Depreciation Expense		1,715,440	1,715,440
	11 Total Return on Average Rate Base and Depreciation Expense in Base Rates		5,550,456	5,043,033
	12 Bison 6 LGIA share of allocated plant costs		18.241%	18.241%
	13 Bison 6 LGIA allocated Return on Rate Base and Depreciation Expense		1,012,459	919,900
	14 Allocated Operation & Maintenance Expense associated with Bison 6 LGIA		159,148	159,148
	15 Annual Base Rate Revenue Credit		1,171,607	1,079,048
	16 MN Jurisdictional Allocator		0.82713	0.82713
	17 MN Jurisdictional Annual Base Rate Revenue Credit 3/		969,071	892,513
	18 Single Lump Sum Related to Transaction Costs 4/		122,601	122,601
	19 Total Base Rate Revenue Credit for first 12 months /5		1,091,672	1,015,114

Notes:

1/ For source document and support, refer to Docket E015/AI-17-304, filed 4/17/2018.

2/ Refer to Exhibit B-4 for rate of return components.

3/ This revenue requirement credit is needed beginning 2/4/2019 until the Company's next rate case.

4/ This is a single lump sum that should only be credited for one year.

5/ This revenue requirement credit is needed beginning 2/4/2018 until 2/4/2019 when it would be replace with credit on line 17.

Revised Attachment 3
Docket No. E015/AI-17-304

Bison 6 LGIA Total Plant Cost Allocation

Project #	Description	Base Rates Net Book Value at Dec 2017	LGIA Cost Allocation /1
	Bison substation		
104431	Sq Butte 230 kV Sub Mod	1,638,351.28	
105422	Ph 1 Group 3	505,442.69	
105111	BISON2 SUB	3,966,631.48	
105440	Bison-Substation for Bison 3 Wind	4,419,878.13	
106799	BISON4 SUB	5,116,925.45	
105476	Bison 230 kV Line Ext	7,196,828.65	
104430	34.5/230 kV Collector Sub	4,567,757.53	
	Sub-total	27,411,815.21	2,982,572.91
	Tri-County Substation		
106805	Tri County Sub	6,000,564.66	
104429	230 kV Trans Line	9,245,617.70	
	Sub-total	15,246,182.36	4,862,659.90
	Center-Mandan		
106277	Center-Hesket Line Blanket	1,991,608.72	
	Sub-total	1,991,608.72	299,317.00
	Gand Total	44,649,606.29	8,144,549.81
	LGIA Allocated Costs %		18.241%

1/Refer to Attachment 4 page 1 and 2 for cost allocations.

Minnesota Power
Renewable Resources Rider: 2019 RRR Factor Filing
PTC True-Up: 2018

Line		Note	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total Year 2018
1	2018 MWh		170,498	153,902	116,206	158,025	112,328	90,095	81,626	85,756	124,014	151,501	125,655	148,910	1,518,517
2	Rate ($/MWh)		24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00	
3	2018 PTC	1/	4,091,954	3,693,659	2,788,947	3,792,608	2,695,876	2,162,276	1,959,017	2,058,152	2,976,342	3,636,020	3,015,730	3,573,830	36,444,410
4	Test Year PTC		4,358,143	3,209,312	4,062,463	4,297,948	3,718,486	2,839,988	2,474,288	2,308,324	2,992,730	4,293,535	4,112,921	3,162,027	41,830,163
5	PTC Over/(Under) Test Year	2/	(266,189)	484,347	(1,273,516)	(505,340)	(1,022,610)	(677,712)	(515,271)	(250,172)	(16,388)	(657,515)	(1,097,191)	411,803	(5,385,753)
6	Deferred Tax Expense	3/	266,189	(484,347)	1,273,516	505,340	1,022,610	677,712	515,271	250,172	16,388	657,515	1,097,191	(411,803)	5,385,753
7	Tax Gross Up	4/	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	
8	Revenue Requirement Impact	5/	373,557	(679,709)	1,787,190	709,169	1,435,081	951,068	723,106	351,079	22,997	922,725	1,539,745	(577,904)	7,558,103
9	Increase/(Decrease) to Avg Mo. Rate Base	6/	(133,094)	(24,016)	(418,600)	(1,308,028)	(2,072,003)	(2,922,164)	(3,518,655)	(3,901,376)	(4,034,656)	(4,371,607)	(5,248,960)	(5,591,655)	
10	Monthly Rate of Return	7/	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	
11	Return on Rate Base	8/	(783)	(141)	(2,464)	(7,700)	(12,197)	(17,202)	(20,713)	(22,966)	(23,750)	(25,734)	(30,898)	(32,916)	(197,464)
12	Tax Gross Up		71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	
13	Rate Base Rev Req Impact	9/	(1,099)	(198)	(3,458)	(10,806)	(17,117)	(24,140)	(29,067)	(32,229)	(33,330)	(36,114)	(43,361)	(46,192)	(277,112)
14	Total Rev Req Impact	10/	372,457	(679,907)	1,783,732	698,363	1,417,965	926,928	694,038	318,850	(10,333)	886,611	1,496,383	(624,097)	7,280,991
15	MN Jurisdictional Allocator	11/	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	
16	MN Jurisdictional PTC True-Up	12/	312,529	(570,510)	1,496,730	585,997	1,189,814	777,785	582,367	267,547	(8,670)	743,955	1,255,615	(523,680)	6,109,480

Notes:
1/ Line 1 x Line 2.
2/ Line 3 - Line 4.
3/ Line 5 x -1.
4/ (1 - 28.742 tax rate)
5/ Line 6 / Line 7
6/ Sum of year to date Line 5 through previous month, plus half of current month Line 5.
7/ Annual Rate of Return (Refer to Exhibit B-4) / 12 to convert to monthly rate.
8/ Line 9 x Line 10
9/ Line 11 x Line 12
10/ Line 8 + Line 13
11/ MP Exhibit 019 Supplemental Direct Volume 4, (SJS) Supplemental Direct C-1, page 15, line 18, column (3) / column (1).
12/ Line 14 x Line 15

Minnesota Power
Renewable Resources Rider: 2020 RRR Factor Filing
PTC True-Up: 2019

Line		Note	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total Year 2019
1	2019 MWh		135,489	109,403	155,070	137,465	131,550	118,463	107,839	116,245	137,816	158,178	160,309	150,881	1,618,706
2	Rate ($/MWh)		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	
3	2019 PTC	1/	3,387,214	2,735,073	3,876,751	3,436,625	3,288,750	2,961,574	2,695,968	2,906,114	3,445,393	3,954,438	4,007,736	3,772,024	40,467,659
4	Test Year PTC		4,358,143	3,209,312	4,062,463	4,297,948	3,718,486	2,839,988	2,474,288	2,308,324	2,992,730	4,293,535	4,112,921	3,162,027	41,830,163
5	PTC Over/(Under) Test Year	2/	(970,929)	(474,239)	(185,712)	(861,323)	(429,736)	121,586	221,680	597,790	452,664	(339,097)	(105,185)	609,998	(1,362,504)
6	Deferred Tax Expense	3/	970,929	474,239	185,712	861,323	429,736	(121,586)	(221,680)	(597,790)	(452,664)	339,097	105,185	(609,998)	1,362,504
7	Tax Gross Up	4/	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	
8	Revenue Requirement Impact	5/	1,362,554	665,525	260,619	1,208,738	603,071	(170,628)	(311,094)	(838,910)	(635,246)	475,872	147,612	(856,041)	1,912,072
9	Increase/(Decrease) to Avg Mo. Rate Base	6/	(485,464)	(1,208,048)	(1,538,024)	(2,061,541)	(2,707,070)	(2,861,146)	(2,689,513)	(2,279,778)	(1,754,551)	(1,697,768)	(1,919,909)	(1,667,503)	
10	Monthly Rate of Return	7/	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	0.5887%	
11	Return on Rate Base	8/	(2,858)	(7,111)	(9,054)	(12,135)	(15,935)	(16,842)	(15,832)	(13,420)	(10,328)	(9,994)	(11,302)	(9,816)	(134,628)
12	Tax Gross Up		71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	71.258%	
13	Rate Base Rev Req Impact	9/	(4,010)	(9,980)	(12,706)	(17,030)	(22,363)	(23,636)	(22,218)	(18,833)	(14,494)	(14,025)	(15,860)	(13,775)	(188,930)
14	Total Rev Req Impact	10/	1,358,543	655,545	247,913	1,191,708	580,708	(194,264)	(333,312)	(857,743)	(649,740)	461,847	131,752	(869,816)	1,723,141
15	MN Jurisdictional Allocator	11/	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	0.83910	
16	MN Jurisdictional PTC True-Up	12/	1,139,954	550,068	208,024	999,962	487,272	(163,007)	(279,682)	(719,732)	(545,197)	387,536	110,553	(729,863)	1,445,888

Notes:
1/ Line 1 x Line 2; Jan - May actuals; Jun - Dec based on 2019 Budget.
2/ Line 3 - Line 4.
3/ Line 5 x -1.
4/ (1 - 28.742 tax rate)
5/ Line 6 / Line 7
6/ Sum of year to date Line 5 through previous month, plus half of current month Line 5.
7/ Annual Rate of Return (Refer to Exhibit B-4) / 12 to convert to monthly rate.
8/ Line 9 x Line 10
9/ Line 11 x Line 12
10/ Line 8 + Line 13
11/ MP Exhibit 019 Supplemental Direct Volume 4, (SJS) Supplemental Direct C-1, page 15, line 18, column (3) / column (1).
12/ Line 14 x Line 15

Minnesota Power
2020 Renewable Resources Rider: Thomson Hydro
Plant Additions, AFUDC and Return on CWIP

	Total Project	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Replace/Refurbish Dam 6	414,677												
ID# 106069													
In Service 12/31/2018												CAPPED	
BOM		230,834	243,819	249,813	260,878	262,182	327,474	327,990	370,663	398,892	407,413	414,677	414,677
CapEx	467,229	20,196	7,698	11,969	5,290	74,848	2,663	44,689	31,650	10,456	7,489		
Less Internal Cost	-52,552	-7,211	-1,703	-904	-3,986	-9,556	-2,147	-2,016	-3,421	-1,934	-225		
AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		243,819	249,813	260,878	262,182	327,474	327,990	370,663	398,892	407,413	414,677	414,677	414,677
Return on CWIP													
After Tax Return on Equity		1,114	1,159	1,199	1,228	1,384	1,539	1,640	1,807	1,893	1,930	1,947	1,947
Income Tax Component		786	818	846	866	977	1,086	1,157	1,275	1,336	1,362	1,374	1,374
Interest Expense Component		502	522	540	554	624	694	739	814	853	870	878	878
Total Return on CWIP		2,403	2,499	2,585	2,648	2,985	3,318	3,537	3,896	4,082	4,162	4,199	4,199
Thomson Spill Capacity	6,122,046												In-Service
ID# 106794													
In Service 12/31/2017												CAPPED	12/31/2017
BOM		1,878,999	1,919,924	2,002,405	2,058,312	2,070,564	2,226,939	2,490,700	3,024,686	3,373,894	4,349,700	6,095,671	6,122,046
CapEx	6,512,178	63,970	96,306	80,083	31,344	180,038	286,200	556,041	377,971	1,021,454	1,778,708	53,196	
Less Internal Cost	-441,417	-23,045	-13,825	-24,176	-19,092	-23,663	-22,439	-22,054	-28,763	-45,648	-32,737	-26,821	
AFUDC	53,042	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-1,756	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	0	0	0	0	0	0	0	0	0	0	0	0	0
EOM		1,919,924	2,002,405	2,058,312	2,070,564	2,226,939	2,490,700	3,024,686	3,373,894	4,349,700	6,095,671	6,122,046	6,122,046
Return on CWIP													
After Tax Return on Equity		8,919	9,208	9,533	9,693	10,089	11,075	12,948	15,022	18,132	24,522	28,683	14,372
Income Tax Component		6,293	6,497	6,727	6,840	7,119	7,815	9,136	10,599	12,794	17,303	20,239	10,141
Interest Expense Component		4,021	4,151	4,298	4,370	4,548	4,993	5,837	6,772	8,174	11,055	12,930	6,479
Total Return on CWIP		19,232	19,857	20,557	20,902	21,756	23,883	27,922	32,393	39,101	52,880	61,852	30,993
Total Thomson Project	84,057,574												
BOM		79,630,683	79,684,594	79,773,069	79,840,041	79,853,597	80,075,264	80,339,540	80,916,200	81,293,637	82,277,964	84,031,199	84,057,574
CapEx	107,971,672	86,402	104,348	92,052	36,635	254,886	288,863	600,730	409,621	1,031,909	1,786,197	53,196	0
Less Internal Cost	-7,075,092	-32,492	-15,872	-25,081	-23,078	-33,219	-24,587	-24,070	-32,183	-47,582	-32,962	-26,821	0
AFUDC	4,602,876	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-297,252	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	-21,144,630	0	0	0	0	0	0	0	0	0	0	0	0
EOM		79,684,594	79,773,069	79,840,041	79,853,597	80,075,264	80,339,540	80,916,200	81,293,637	82,277,964	84,031,199	84,057,574	84,057,574
Return on CWIP													
After Tax Return on Equity	745,873	10,033	10,367	10,732	10,921	11,473	12,614	14,588	16,828	20,025	26,452	30,630	16,319
Income Tax Component	526,297	7,079	7,315	7,573	7,706	8,096	8,901	10,294	11,874	14,130	18,665	21,613	11,515
Interest Expense Component	336,245	4,523	4,674	4,838	4,923	5,172	5,687	6,577	7,586	9,027	11,925	13,808	7,357
Total Return on CWIP	1,608,414	21,635	22,356	23,143	23,550	24,741	27,201	31,459	36,289	43,183	57,042	66,051	35,191

Minnesota Power
2020 Renewable Resources Rider: Thomson Hydro
Plant Additions, AFUDC and Return on CWIP

	Total Project	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Replace/Refurbish Dam 6	414,677										In-Service		
ID# 106069													
In Service 12/31/2018											10/11/2018		
BOM		414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677		
CapEx	467,229												
Less Internal Cost	-52,552												
AFUDC	0	0	0	0	0	0	0	0	0	0	0		
Less AFUDC on Internal Cost	0	0	0	0	0	0	0	0	0	0	0		
Less Insurance Proceeds	0	0	0	0	0	0	0	0	0	0	0		
EOM		414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677	414,677		
Return on CWIP													
After Tax Return on Equity		1,949	1,949	1,949	1,720	1,720	1,720	1,720	1,720	1,720	860		
Income Tax Component		786	786	786	694	694	694	694	694	694	347		
Interest Expense Component		878	878	878	721	721	721	721	721	721	360		
Total Return on CWIP		3,613	3,613	3,613	3,135	3,135	3,135	3,135	3,135	3,135	1,567		
Thomson Spill Capacity	6,122,046												
ID# 106794													
In Service 12/31/2017													
BOM													
CapEx	6,512,178												
Less Internal Cost	-441,417												
AFUDC	53,042												
Less AFUDC on Internal Cost	-1,756												
Less Insurance Proceeds	0												
EOM													
Return on CWIP													
After Tax Return on Equity													
Income Tax Component													
Interest Expense Component													
Total Return on CWIP													
Total Thomson Project	84,057,574												
BOM		84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574
CapEx	107,971,672	0	0	0	0	0	0	0	0	0	0	0	0
Less Internal Cost	-7,075,092	0	0	0	0	0	0	0	0	0	0	0	0
AFUDC	4,602,876	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC on Internal Cost	-297,252	0	0	0	0	0	0	0	0	0	0	0	0
Less Insurance Proceeds	-21,144,630	0	0	0	0	0	0	0	0	0	0	0	0
EOM		84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574	84,057,574
Return on CWIP													
After Tax Return on Equity	745,873	1,949	1,949	1,949	1,720	1,720	1,720	1,720	1,720	1,720	860	0	0
Income Tax Component	526,297	786	786	786	694	694	694	694	694	694	347	0	0
Interest Expense Component	336,245	878	878	878	721	721	721	721	721	721	360	0	0
Total Return on CWIP	1,608,414	3,613	3,613	3,613	3,135	3,135	3,135	3,135	3,135	3,135	1,567	0	0

Minnesota Power
MPUC Docket E015/GR-09-1151
Rate of Return / Cost of Capital Summary
(thousands of dollars)
Commission Decision (9/29/2010)

	Average for 13 months Ended 12/31/10						
	Amount	% of Total	Component Cost	Weighted Cost	Pre-tax Rate	After-Tax Rate
Long Term Debt	$ 696,677	45.71%	5.56%	2.540%	2.540%	1.490%
Common Equity	$ 827,534	54.29%	10.38%	5.640%	9.610%	5.640%
	$ 1,524,211	100.00%		8.180%	12.150%	7.130%

Federal & State Income Tax Rate	41.37%	
Pretax "Gross-up" Factor	1.70560	
After Tax Return on Equity	5.6343%	1/
Income Tax Component	3.9757%	2/
Interest Expense Component	2.5400%	
Pre-tax Return	12.1500%	

1/ Rounding forced to equity.
2/ Shown here as a component of the pretax rate of return. Can also be computed as 70.56% gross up on After Tax Return on Equity.

Adjusted to Reflect Tax Reform 1/1/2018

	Average for 13 months Ended 12/31/10					
	Amount	% of Total	Component Cost	Weighted Cost	Pre-tax Rate	After-Tax Rate
Long Term Debt	$ 696,677	45.71%	5.56%	2.540%	2.5400%	1.810%
Common Equity	$ 827,534	54.29%	10.38%	5.640%	7.9149%	5.640%
	$ 1,524,211	100.00%		8.180%	10.4549%	7.450%

Federal & State Income Tax Rate	28.742%	
Pretax "Gross-up" Factor	1.40340	
After Tax Return on Equity	5.6400%	1/
Income Tax Component	2.2749%	2/
Interest Expense Component	2.5400%	
Pre-tax Return	10.4549%	

1/ Rounding forced to equity.
2/ Shown here as a component of the pretax rate of return. Can also be computed as 40.34% gross up on After Tax Return on Equity.

Minnesota Power
MPUC Docket E015/GR-16-664
Rate of Return / Cost of Capital Summary
(thousands of dollars)
Supplemental Direct
Used Starting 4/1/2018 Following 3/12/2018 Order

	Average for 13 months Ended 12/31/17					
	Amount	% of Total	Component Cost	Weighted Cost /1	Pre-tax Rate	After-Tax Rate
Long Term Debt	$ 1,228,550	46.1892%	4.5170%	2.0864%	2.0864%	1.490%
Common Equity	$ 1,431,272	53.8108%	9.2500%	4.9775%	6.9852%	4.978%
	$ 2,659,822	100.00%		7.0639%	9.0716%	6.468%

Federal & State Income Tax Rate	28.7420%	
Pretax "Gross-up" Factor	1.403350	
After Tax Return on Equity	4.9775%	1/
Income Tax Component	2.0077%	2/
Interest Expense Component	2.0864%	
Pre-tax Return	9.0716%	

1/ Commission 3/12/2018 Order, point #2.
2/ Company's Initial Filing in the Commission Investigation into the Effects of the 2017 Federal Tax Act, March 2, 2018, Attachment 5, page 1. Docket No. E, G-999/CI-17-895.
3/ Shown here as a component of the pretax rate of return. Can also be computed as 40.34% gross up on After Tax Return on Equity.

Minnesota Power
Renewable Resources Rider
Allocation Factors

Allocation factors used beginning 4/1/2011

	D-01		D-02	
	Rate Case	Normalized	Rate Case	Normalized
MN Jurisdiction	0.82017	1.0000	0.77570	1.0000
Residential	0.11259	0.1373	0.10649	0.1373
General Service	0.06213	0.0758	0.05876	0.0758
Large Light & Power	0.12471	0.1521	0.11795	0.1521
Large Power	0.51269	0.6251	0.48489	0.6251
Municipal Pumping	0.00568	0.0069	0.00537	0.0069
Lighting	0.00237	0.0029	0.00224	0.0029

The D-01 and D-02 allocators from MP's 2009 MPUC rate case Docket No. E-015/GR-09-1151 were applied in 2011 Factor Filing begining April 2011.
Because the revenue tracker amounts are 100% MN Jurisdictional, the factors are normalized to obtain class allocations.
Refer to Exhibit B-5, page 2.

Allocation factors used beginning 4/1/2018

	D-01		D-02	
	Rate Case	Normalized	Rate Case	Normalized
MN Jurisdiction	0.84360	1.0000	0.82713	1.0000
Residential	0.10655	0.1263	0.10449	0.1263
General Service	0.06625	0.0785	0.06495	0.0785
Large Light & Power	0.14604	0.1731	0.14318	0.1731
Large Power	0.52030	0.6168	0.51014	0.6168
Municipal Pumping	0.00193	0.0023	0.00189	0.0023
Lighting	0.00253	0.0030	0.00248	0.0030
check	-	-	-	-

The D-01 and D-02 allocators from MP's 2016 MPUC rate case Docket No. E-015/GR-16-664 are applied begining 12/1/2018 assumed to be coincident with Final Rate implementation in rate case.
Because the revenue tracker amounts are 100% MN Jurisdictional, the factors are normalized to obtain class allocations.
Refer to Exhibit B-5, page 3.

Minnesota Power
Docket No. E-015/GR-09-1151
Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
Test Year 2010 Rebuttal Customer Budget
Revised from original work paper AF-3, page 14.

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses)	8,973,590	1,164,063	645,945	1,311,171	5,768,410	61,116	22,885
2	Average Demand	1,024,382	132,884	73,738	149,677	658,494	6,977	2,612
3	Percent	100.000	12.972	7.198	14.611	64.282	0.681	0.255
4	Annual CP Demand (loss adjusted)	1,267,035	214,342	116,138	224,399	697,256	9,334	5,567
5	Percent	100.000	16.917	9.166	17.711	55.031	0.737	0.439
6	Annual Load Factor (Line 2 / Line 4)	0.80849						
7	1.0 - Load Factor	0.19151						
8	Average Factor (Line 3 x Line 6 total)	80.849	10.488	5.820	11.813	51.971	0.551	0.206
9	Peak Factor (Line 5 x Line 7 total)	19.151	3.240	1.755	3.392	10.539	0.141	0.084
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	13.728	7.575	15.205	62.510	0.692	0.290
11	Power Supply Production - D-01 Adjusted for Jurisditional Split (Line 10 x .82017)	82.017	11.259	6.213	12.471	51.269	0.568	0.237
12	Power Supply Transmission - D-02 Adjusted for Jurisditional Split (Line 10 x .77570)	77.570	10.649	5.876	11.795	48.489	0.537	0.224

Notes:
Residential, General Service, Large Light and Power and Municipal Pumping CP demands per customer from load research multiplied by budgeted number of customers and adjusted for losses. Large Power CP demand based on 2008 CP adjusted for losses and ratio of 2008 to Test Year average demand. Large Light and Power and Large Power loads normalized to reflect three cusomters that moved from Large Power to Large Light and Power. Lighting CP is average load based on Test Year budgeted total energy and 4,200 burning hours and adjusted for losses.

Allete, Inc., d/b/a Minnesota Power
Docket No. E-015/GR-16-664
Demand Responsibility of Power Supply Cost Based on Peak & Average Methodology: D-01 & D-02
2017 Test Year 2/28/2017 Supplemental Filing

		Total Retail	Residential	General Service	Large Light & Power	Large Power	Municipal Pumping	Lighting
1	Annual Energy (E-01 with losses, excl. dual fuel)	8,795,413	1,048,806	682,004	1,544,886	5,477,638	18,171	23,907
2	Average Demand	1,004,043	119,727	77,854	176,357	625,301	2,074	2,729
3	Percent	100.000	11.924	7.754	17.565	62.278	0.207	0.272
4	Annual CP Demand (loss adjusted)	1,142,421	203,013	97,884	176,764	654,612	4,413	5,734
5	Percent	100.000	17.770	8.568	15.473	57.300	0.386	0.502
6	Annual Load Factor (Line 2 / Line 4)	0.87887						
7	1.0 - Load Factor	0.12113						
8	Average Factor (Line 3 x Line 6 total)	87.887	10.479	6.815	15.437	54.735	0.182	0.239
9	Peak Factor (Line 5 x Line 7 total)	12.113	2.152	1.038	1.874	6.941	0.047	0.061
10	Composite Factor - D-01 (Line 8 + Line 9)	100.000	12.631	7.853	17.311	61.676	0.229	0.300
11	Power Supply Production - D-01 Adjusted for Jurisditional Split (Line 10 x .84360)	84.360	10.655	6.625	14.604	52.030	0.193	0.253
12	Power Supply Transmission - D-02 Adjusted for Jurisditional Split (Line 10 x .82713)	82.713	10.449	6.495	14.318	51.014	0.189	0.248

Notes:

Residential, General Service, Large Light and Power and Municipal Pumping CP demands per customer from load research multiplied by number of customers and adjusted for losses. Large Power CP demand estimated based on 2017 budgeted average demand and the ratio of Large Power CP demand to Large Power average demand from 2012 -2015. Lighting CP is average load based on 2017 Test Year energy and 4,200 burning hours and adjusted for losses.

STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
	) ss	ELECTRONIC FILING
COUNTY OF ST. LOUIS	)	

Jodi Nash of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 15th day of August, 2019, she served Minnesota Power's Renewable Resources Rider and 2020 Renewable Factor on the Minnesota Public Utilities Commission and the Minnesota Department of Commerce via electronic filing. The persons on Minnesota Power's General Service List (attached) were served.

____

Jodi Nash

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	Yes	GEN_SL_Minnesota Power_MPs General Service List
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	GEN_SL_Minnesota Power_MPs General Service List
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Hillary	Creurer	hcreurer@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	Yes	GEN_SL_Minnesota Power_MPs General Service List
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
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Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	Yes	GEN_SL_Minnesota Power_MPs General Service List
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
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	GEN_SL_Minnesota Power_MPs General Service List
Susan	Romans	sromans@allete.com	Minnesota Power	30 West Superior Street Legal Dept Duulth, MN 55802	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Minnesota Power_MPs General Service List