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AN ALLETE COMPANY

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February 14, 2020

**VIA E-FILING**
Will Seuffert
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-19-523**
**Reply Comments**

Dear Mr. Seuffert:

Minnesota Power submits to the Minnesota Public Utilities Commission its Reply Comments in response to the Department of Commerce, Division of Energy Resources Initial Comments filed on December 23, 2019. Minnesota Power provides the requested information, as well as additional context and clarification in response to the questions, concerns and points raised in the Department's Initial Comments.

Certain portions of these Reply Comments contain trade secret information and are marked as such, pursuant to the Commission's Revised Procedures for Handling Trade Secret and Privileged Data, which procedures further the intent of Minn. Stat. § 13.37 and Minn. Rule 7829.0500.

Please contact me at (218) 355-3601 or lhoyum@mnpower.com with any questions related to this matter.

Yours truly,

Lori Hoyum

Lori Hoyum
Policy Manager

LH:th
Attach.

**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-19-523 **REPLY COMMENTS** |

## I. INTRODUCTION

Minnesota Power (or the "Company") submits to the Minnesota Public Utilities Commission ("Commission") its Reply Comments in the above-referenced Docket. On December 23, 2019, the Department of Commerce, Division of Energy Resources ("Department") filed Initial Comments following review of the Company's August 15, 2019 Petition ("Petition") seeking Commission approval of its 2020 rate adjustment mechanism under its Commission-approved Rider for Renewable Resource ("Renewable Resources Rider" or "RRR"). The Department requested that Minnesota Power provide in its Reply Comments related to its proposed sales of renewable energy credits ("RECs") to Oconto Electric Cooperative ("Oconto"):

- The price it will receive for the RECs its sells to Oconto, along with an explanation of how that price is determined;
- An explanation of how the number of RECs sold to Oconto each year will be determined;
- An explanation of whether and how the total amount of revenue received from Oconto for the sale of RECs will be allocated to Minnesota Power's different jurisdictions; and
- Supporting calculations showing how the proposed revenue credits for 2019 and 2020 in the RRR were estimated.

Additionally, the Department requested that the Company explain why the proposed reduction of the credit to ratepayers, from what was represented in its petition for approval to sell the Large Generator Interconnection Agreement ("LGIA") to its affiliate, ALLETE

Clean Energy, Inc., is reasonable. Finally, the Department requested Minnesota Power provide a response to the Department's proposal for estimating a true-up amount to include in the 2020 factors; and actual 2017 and 2018 rate base and operation and maintenance ("O&M") costs associated with the Bison Wind Energy Center ("Bison Wind")[1] and Thomson Hydroelectric Restoration Project ("Thomson Project") that were rolled into base rates in the 2016 rate case.[2]

Through these Reply Comments, Minnesota Power provides the requested information, as well as additional context and clarification in response to the questions, concerns and points raised in the Department's Initial Comments. Additionally, attached are new exhibits A-1 and B-1 through B-5 which have been revised to reflect the Department's requested calculation updates. A new exhibit, Exhibit B-6, showing the Department's recommended calculation method to true-up for the Bison and Thomson projects, as well as an updated 2017 tracker, is also attached.

## II. REPLY COMMENTS

Table 1 reflects the revenue requirements impacts that are discussed in the following sections and identified in the attached exhibits.

Table 1 – Revenue Requirements Impacts and Updated RRR Factor

| | |
|---|---|
| August 15, 2019 Petition Total RRR Factor *(Exhibit B-1, pg. 1)* | $1,123,181 |
| Tax Depreciation Impact *(Exhibit: n/a)*<br>*Thomson Project - Replace/Refurbish Dam 6* | ($714) |
| ROE[3] / Allocation Factor Adjustment to 1/1/17 Impact *(Exhibit: n/a)* | ($67,897) |
| Interim Rate Period Under-collection Impact *(Attached Exhibit B-6)* | $1,984,093 |
| **Update Total RRR Factor *(Attached Exhibit B-1, pg. 1)*** | **$3,038,663** |

[1] 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).
[2] Docket No. E015/16-664.
[3] Return on Equity (ROE).

Minnesota Power first provides the information requested by the Department specific to the proposed sales of RECs to Oconto.

### A. Sale Agreement with Oconto for RECs

Minnesota Power entered into a power sales agreement ("Agreement") with Oconto for the period of January 2019 through May 2026 that includes selling excess renewable energy credits to assist Oconto in meeting Wisconsin's Renewable Portfolio Standard. Selling RECS to Oconto will have no impact on the Company's ability to meet its obligation as set forth in Minnesota's RES (Renewable Energy Standard) (Minn. Stat. § 216B.1691, subd. 3(b)). Minnesota Power expects to maintain compliance with the RES through 2053 with its current renewable portfolio, the longest duration of any utility in Minnesota.[4]

*Selling Price*

The Agreement appropriately compensates customers for the sale of the RECs. The price Minnesota Power receives for the RECs sold to Oconto is a price adder to

**[TRADE SECRET DATA EXCISED]** to Oconto. The REC adder is **[TRADE SECRET DATA EXCISED]** The REC adder price was **[TRADE SECRET DATA EXCISED]** With the

**[TRADE SECRET DATA EXCISED]**

(see Table 1).

*Determination of Number Sold*

Per the Agreement, Minnesota Power will provide Oconto with

[4] 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.

**[TRADE SECRET DATA EXCISED]**

The RECs the Company provides are

**[TRADE SECRET DATA EXCISED]**

For example,

**[TRADE SECRET DATA EXCISED]**

*Jurisdictional Allocation of Revenue Received from Oconto*

The Company used the Energy Jurisdictional Allocator or (E-01) approved in its 2016 rate case (Docket No. E015/GR-16-664). In the example shown in Table 2, $18,350 is multiplied by the commission-approved (E-01) of 0.84307 to arrive at the jurisdictional revenue credit.

*Calculation of Estimated 2019 & 2020 Revenue Credits*

Table 2 shows how the proposed revenue credits for 2019 and 2020 were estimated in the Petition. The amount of reimbursement to customers for 2019 is included in the calculation of the RRR factor as shown in Exhibit B-1, page 1 of the Petition. January 2019 through March 2019 amounts reflect actual sales while the remaining nine months of 2019 are estimated sales approximated using the first three monthly numbers.

Table 2- Oconto Revenue Credit Calculation

| | | 2019 | 2020 |
|---|---|---|---|
| A | **[TRADE SECRET DATA EXCISED]** | | |
| B | **[TRADE SECRET DATA EXCISED]** | | |
| C = A x B | Total Revenue Credit | $18,150 | $18,350 |
| D | Jurisdictional Split | 0.84307 | 0.84307 |
| E= C x D | Jurisdictional Revenue Credit | $15,302 | $15,470 |

The credit to customers from the Oconto RECs was added after Minnesota Power finalized its 2019 budget. Therefore, the Company recorded the actual sale of RECs in the tracker through the first three months of 2019, and used these actuals as the basis to estimate the remaining months in 2019. Without at least a full year of historical actual sales data to use for the 2020 budget, the budgeted annual credits for RECs were parsed out by month[5] at a constant rate based on the number of days in each month. Minnesota Power expects the budgeting process for the sale of RECs to Oconto to be refined once there is more historical data available.

### B. LGIA Bison 6 Customer Credit Adjustment

The Company appreciates the Department's time and effort in reviewing the LGIA revenue requirement calculations and resulting support of the corrected allocator of 18.241 percent for costs related to the Bison 6 LGIA related property and moving the LGIA credit from the RRR to base rates. Minnesota Power had inadvertently used a 28.504 percent allocator in the calculations in its Initial petition submitted on April 19, 2017 in Docket No. E015/AI-17-304. The use of the incorrect allocator was identified in the preparation of the August 15, 2019 RRR Petition and corrected.

[5] Example: January 2020 is 31 days = 1,310 in comparison to February 2020 is 29 days = 1, 226).

*Transparency of the Customer Credit Change*

The Department expressed concern that Minnesota Power "didn't file anything about the error resulting in a 36% lower credit for ratepayers than what MP had represented in the Affiliate/Bison 6 LGIA Docket (AI-17-304)." The Department went on to say, "[t]his error is particularly concerning since MP's proposal would benefit the Company's affiliate at MP's ratepayers' expense." The Company did not intentionally forego supplementing Docket No. E015/AI-17-304 regarding the corrected calculation and lower credit to customers. On June 5, 2018, less than three months after the March 16, 2018 Order in the afore-mentioned Docket, Minnesota Power submitted its 2018 Renewable Resources Rider and 2018 Renewable Factors Petition.[6] The 2018 RRR calculations included reimbursements to customers related to the Bison LGIA transfer as documented in the April 17, 2018, and May 7, 2018 compliance filings.[7] On November 19, 2018, the Commission issued an order approving the 2018 Renewable Factors, including the reimbursement to customers, and the updated 2018 RRR Factors went into effect December 1, 2018.

It is not routine for utilities to submit documents into the original dockets in which Commission approval was sought for adjustments that occur in the cost recovery dockets. For this reason, and the fact customers have been reimbursed since December 1, 2018, it wasn't intuitive to the Company that submitting notice of the change in allocator and customer credit in Docket No. E015/AI-17-304 was necessary. In hindsight, Minnesota Power agrees with the Department that the Company should have more thoroughly considered all of the dockets affected by the corrected calculation, as well as communication within the Petition specific to the updated calculation. The Company will make a concerted effort to file information in all related dockets going forward.

*The Proposed Reduction to the Customer Credit is Reasonable*

In the Department's December 23, 2019 Initial Comments, the Department stated,

[6] Docket No. E015/M-18-375.
[7] See Exhibit B-2 pg. 7 of initial Petition in Docket No. E015/M-18-375.

> "After reviewing MP's calculations in its Petition and the related information from the LGIA Docket, the Department concluded that MP's initial calculation of the allocator from the LGIA Docket contained an error that the Company corrected in this Petition. In its response to DOC IR No. 9, MP confirmed the error and the correction. The Department concludes that MP's calculation in this Petition is correct, and that 18.241 percent is the correct allocator to use to allocate the costs of the Bison 6 LGIA related property."

The first and primary reason why it is reasonable to decrease the customer credit is that the 18.242 percent allocator has been verified by the Department as the correct allocator to use for cost allocation of the Bison 6 LGIA related property. While the lower allocator results in a decreased credit to customers from what was represented in the original filing, it is not only reasonable, crediting customers the fair amount for ALLETE Clean Energy, Inc.'s ("ACE") use of the facilities, the premise of the Commission's decision, is also the right thing to do.

Secondly, the lower allocator percentage does not change what ACE paid for the transfer of the Bison LGIA - approximately $8 million, and does not affect the contracts with ACE in any way.

Lastly, Minnesota Power customers received a significant benefit when the Commission determined customers would begin being credited effective February 4, 2018, instead of December 2019 when ACE began using the facilities as proposed by the Company. This decision is not consistent with effective dates determined for other agreements as the Company argued in Docket No. E015/AI-17-304. As a result, Minnesota Power began crediting customers for use of the facilities 22 months prior to when ACE became a joint user of the facilities. This equates to an approximately $1.67 million benefit to customers.

It is important to note that the attached Exhibit B-2 includes a further change to the customer credit resulting from the Department's request in its Information Request No. 5 requesting Minnesota Power to adjust the jurisdictional allocation factors and ROE

(Return on Equity) back to January 1, 2017, the effective date of interim rates for the Company's 2016 rate case[8] (shown in updated Exhibit B-2, page 6). [9]

### C. True-ups & Tracker Balances

As detailed in the Department's Initial Comments on page 13, a normal true-up procedure cannot be used for the 23-month interim rate period because many of the components of the revenue requirements for the projects rolled into base rates in the 2016 rate case were already included in the interim rate refund calculation at the conclusion of Minnesota Power's 2016 rate case. Exhibit B-6 is the Company's estimate of the true-up based upon the Company's understanding of the Department's request.[10] To develop the true-up, Minnesota Power started with the rate base and O&M estimates from the most recent filings containing all of the projects. This information was modified to include previously removed internal costs and AFUDC on internal costs, as the amounts rolled into Minnesota Power's 2017 Test Year included both of those, resulting in a larger rate base and larger credit to customers. The 2017 data was extended to each project on a monthly basis for all of 2018. Then the differences in tax and book basis were calculated (Jan 2018 minus Jan 2017 for example) to come up with a decrease in rate base that could be attributed to changes in tax and book basis in 2018 relative to 2017. This change was then multiplied by the rate of return established in the Company's 2016 rate case to develop a true-up amount associated with the additional depreciation in 2018. O&M for both 2017 and 2018 is compared against the 2017 estimate previously provided. This amount is also included in the true-up outlined in Exhibit B-6. The true-up is then netted against the $4.65 million cash collection shortfall as discussed in the second paragraph of page 14 of the Department's Initial Comments.

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

[9] Department Information Request No. 5 dated October 16, 2019: "Please provide actual 2017 and 2018 revenue requirements for all projects that were included in the Renewable Resources Rider at the time MP filed its 2017 rate case in Docket No. E015/GR-16-664 (i.e. all projects included in the above-referenced exhibits). Please provide the revenue requirement calculations in the same format as the above-referenced exhibits."

[10] See Page 13 of Department's Initial Comments.

## D. Updated Rate Impacts from Adjusted Factors

Table 3 summarizes the updated estimated rate impacts by customer class. The rate increase in cents per kWh shown in Table 3 is the incremental change between the current 2018 Renewable Factors and the updated 2020 Renewable Factors in this filing.

Based on the above assumptions, all of the Non-LP classes would have an average rate increase of 0.310 cents per kWh. For an average residential customer this would be about a 2.86% increase or about $2.25 more per month. The LP average class rate would remain nearly the same with a small increase of 0.016 cents per kWh or an increase of about 0.26%.

**Table 3. Estimated Customer Impact**

| | |
|---|---|
| **Rate Class Impacts 1/** | |
| **Residential** | |
| Average Current Rate (¢/kWh) | 10.846 |
| Increase (Decrease) (¢/kWh) | 0.310 |
| Increase (Decrease) (%) | 2.86% |
| Average Impact ($/month) | $2.25 |
| | |
| **General Service** | |
| Average Current Rate (¢/kWh) | 10.805 |
| Increase (Decrease) (¢/kWh) | 0.310 |
| Increase (Decrease) (%) | 2.87% |
| Average Impact ($/month) | $8.52 |
| | |
| **Large Light & Power** | |
| Average Current Rate (¢/kWh) | 8.247 |
| Increase (Decrease) (¢/kWh) | 0.310 |
| Increase (Decrease) (%) | 3.76% |
| Average Impact ($/month) | $765 |
| | |
| **Large Power** | |
| Average Current Rate (¢/kWh) | 6.176 |
| Increase (Decrease) (demand + energy combined) (¢/kWh) | 0.016 |
| Increase (Decrease) (%) | 0.26% |
| Average Impact ($/month) | $8,932 |
| | |
| **Lighting** | |
| Average Rate (¢/kWh) | 16.171 |
| Increase (Decrease) (¢/kWh) | 0.310 |
| Increase (Decrease) (%) | 1.92% |
| Average Impact ($/month) | $1.05 |

**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.

### E. Correction to Thomson Restoration Project Final Cost

In the course of responding to the Department's information request numbers 123 and 148 in the Company's 2019 retail rate case (Docket No. E015/GR-19-442), Minnesota Power discovered that certain numbers included on pages 36-37 of the Direct Testimony of Joshua J. Skelton and in the 2020 RRR Petition were incorrect. Specifically, these documents should state that the Thomson Restoration Project was finalized at $94.3 million rather than $93.3 million (page 36, line 21), that $84.5 million rather than $83.5 million was approved for inclusion in base rates in the 2016 Rate Case (page 36, line 22), and that Minnesota Power requests that the $3.9 million rather than $2.9 million (page 37, line 1) in excess of the initial $90.4 million estimate be included in base rates. Additionally, the Thomson Spillway and Dam 6 Projects were completed at a final cost of $10.1 million rather than $9.8 million (page 36, line 26), and there is $7.1 million currently in the RRR rather than $6.98 million (page 36, line 27). Minnesota Power will make an errata filing in the rate case docket to correct these numbers in Mr. Skelton's Direct Testimony.

In addition, the Company is providing additional explanation regarding the soft cap on the Thomson Restoration Project costs established in Minnesota Power's RRR docket (March 5, 2015 Order in Docket E015/M-14-577), particularly related to the calculations used to reach the soft cap amounts. Minnesota Power applied a soft cap of $84.1 million for cost recovery revenue requirement purposes, which was calculated by taking the $90.4 million cost estimate (soft cap) from the original petition for the entire Thomson Restoration Project, including the Thomson Spillway and Dam 6 Projects (Docket No. E015/M-14-577) and removing internal costs, AFUDC on internal costs, and wholesale AFUDC. When the $84.1 million was reached, the total project costs (including internal costs, AFUDC on internal costs, and wholesale AFUDC) were $91.7 million, which is $1.3 million higher than the original estimate (soft cap) due to higher than estimated costs that were not counted toward the adjusted $84.1 million (soft cap).

## F. Other Issues Raised by the Department

*Tax Depreciation*

The Department recommends that the Commission require the Company to update its revenue requirements calculation for THM Replacement/Refurbish Dam 6 project of the Thomson Project to include tax depreciation since Minnesota Power confirmed revenue requirements should include tax depreciation. This revision resulted in a reduction in revenue requirements of $714. The updates have been made in the RRR Tracker and will be noted in the Company's anticipated compliance filing follow receipt of the order in this Docket.

*Rate of Return & Class Allocators*

The Department took issue with the Company applying the jurisdictional allocation factors and rate of return from Minnesota Power's last rate case (Docket No. E015/GR-16-664) beginning in April in 2018, as the allocation factors were developed based on the 2017 test year. Minnesota Power has revised the calculations shown in the accompanying exhibits to reflect applying those allocation factors and the corresponding rate of return coinciding with the start of 2017. This revision resulted in a reduction in revenue requirements of $67,897.

*Bison Wind Projects Wind Production Reporting*

The Department continues to express concern about the low levels of energy production at the Bison wind projects, relative to the projected levels of production Minnesota Power assumed in their respective eligibility filings. The Company most recently addressed the Department's concerns in its August 16, 2018 Reply Comments in Docket No. E015/M-18-375,[11] including acknowledging Bison 1, 2 and 3 wind projects, primarily, have underperformed compared to the initial estimates; and that the Company expects future performance for these units to be similar to past production levels. The Company also

[11] *In the Matter of Minnesota Power's Renewable Resources Rider and 2018 Renewable Factor (pg. 5).*

identified contributing factors to why there is a discrepancy between initially estimated and actual production levels which are discussed below.

**Early Adopter - 2007 Next Generation Energy Initiative**

As early as 2006, Minnesota Power entered into a power purchase agreement with NextEra for a 50.6 MW purchase from the Oliver County wind project located in North Dakota. A similar agreement with Next Era was executed in 2007. At the same time, the Company was developing its first owned and operated wind farm – the 25 MW Taconite Ridge Energy Center in northern Minnesota became operational in 2008. During this same timeframe, the Company evaluated wind development opportunities in the central region of North Dakota which has high average wind speeds. The eligibility filing for the Bison 1 Wind Project, the Company's first wind farm in North Dakota, was submitted to the Commission for approval in March 2009. Approximately two years later, in March and June 2011, respectively, the eligibility filings for the Bison 2 and 3 wind projects were submitted to the Commission.

**Maturity of Wind Industry and Operational Experience Data**

There are many complex assumptions used in developing estimated future production levels, and as time has shown the quality of the available data and assumptions used are critical to the accuracy of these projections. The regional wind industry was relatively new and there was considerably less wind data and operational experience on which to develop projections during this timeframe than there is available today. Furthermore, there was an extremely short timeframe between when Bison Phase 1A became commercially operational in December 2010 and the submittal of the eligibility filings for the Bison 2 and 3 wind projects in March 2011 and June 2011, respectively. Consequently, no analysis or lessons learned from the Company's operational experience with the first phase of the Bison 1 Wind Project[12] could be considered, as the

[12] Phase 1A of the Bison 1 Wind Project became commercially operational in December 2010 – less than six months prior to filing the eligibility filings for Bison 2 and 3 wind projects. Phase 1B of the Bison 1 Wind Project became commercially operational in January 2012 – more than six months after submitting the eligibility filings for the Bison 2 and 3 wind projects. These projects became commercially operational in December 2012.

data for Bison 2 and 3 wind projects needed to be locked in before Bison Phase 1A became operational.

**Regulators' Recommendation and Requirements**

On October 5, 2009, Minnesota Power submitted its 2010 Integrated Resource Plan.[13] The Company clearly and concisely stated the timing and actions specific to obtaining renewable resources over the next five-year period:

- Construct the 75.9 MW Bison 1 wind-based renewable resource in North Dakota through a phased implementation to be completed late 2011; and
- Evaluate in the next 24 months the implementation timing for an including an additional 300 MW of wind additions near Center, North Dakota.

In the May 6, 2011 Order *Accepting Resource Plan and Requiring Compliance Filings* the Commission concurred with the Department's recommendation that Minnesota Power should consider additional wind generation.[14] Order Point 4 of the May 6, 2011 Order states:

4. Minnesota Power shall give strong consideration to adding 100 MW of wind during the current production tax credit cycle beyond the Company's own expected timeline for wind additions recognizing the Company's announcement in Docket No. E-015/M-11-234 to add 105 MW of wind capacity by the end of 2012. The Commission will revisit the issue of further wind additions at the time it considers Docket No. E-015/M-11-234.

Based on the positive reaction by stakeholders to the Company's intent to proceed with the next phase of wind development in North Dakota and regulators directive to strongly consider additional wind generation, Minnesota Power, in compliance with Order Point 4, submitted its eligibility filing for the Bison 3 Wind Project in June 2011, which used similar data to what had been used in determining projected levels of production for Bison 2.

[13] Docket No. E015/RP-09-1088.
[14] Page 7.

Had the Company implemented its short-term action plan as proposed and not accelerated the timing of its future wind development, it's possible that the Bison 3 Wind Project production would also be more in line with expectations, and the Bison 4 Wind project estimations refined to be even closer to expectations. Minnesota Power has shown the importance of applying lessons learned in the successful execution of significant projects over the past several years, including wind generation projects.

**Operational Data Benefits Bison 4 Wind Project Production Level Projections**

By the time the Bison 4 Wind Project eligibility filing was submitted in September 2013, there was much more data on which to develop projections – both from the Company's experience operating the Bison Wind Energy Center for three years, as well as from the wind industry overall. Consequently, the Bison 4 Wind Project is performing closer to expectation than the Bison 1, 2 and 3 wind projects.[15]

The Department recommends that the Company be required to continue to report production levels at the Bison Wind Energy Center so the situation can be monitored.[16] Minnesota Power believes this is unnecessary since the Company has been and will continue to report Bison generation in the Fuel Adjustment Clause Forecast True Up filings each year. Based on the facts above, the Company respectfully requests to cease this additional reporting requirement and free up resources for other Commission initiatives and compliance actions. Alternatively, the Company is agreeable to setting a threshold for triggering reporting in future RRR filings based on a more realistic expectation of production levels of these units.

Regardless of the Commission's decision on future reporting, Minnesota Power customers have and will continue to receive significant value and benefits from the Bison

[15] The Company noted on page 24 of its Petition that 2018 production at Bison 4 was negatively impacted by a high number of inverter module failures, which prompted the turbine manufacturer to replace all Bison 4 inverter modules. This issue reduced Bison 4's availability by approximately 4 percent in 2018. The modules were replaced at no cost to the Company.

[16] Order Point 4 of the Commission's November 19, 2018 in Docket No. E015/M-180375 requires Minnesota Power to provide in all future RRR flings the action production for the Bison projects over the prior year and explain any underperformance compared to the 1,888,000 megawatt-hours assumed in the eligibility filings.

Wind Energy Center that has enabled Minnesota Power to meet the Minnesota Renewable Energy Standard requirement (25 percent by 2025) a decade early.

## III. CONCLUSION

Minnesota Power appreciates the opportunity to respond to the questions and concerns expressed by the Department in Initial Comments, as well as the requested information. The Company was thorough and transparent in its responses. Transparency is a core discussion point with all filings. The Commission, Department and stakeholders should be assured that any perceived lack of transparency on the Company's part is not intentional. This extremely busy time in the energy industry and regulatory environment is increasing workload and constraining resources for utilities, regulators and stakeholders alike.

Minnesota Power appreciates the time spent by the Department in reviewing the Petition and respectfully requests the Commission approve the 2020 RRR Factor as modified herein, including the Company's request to eliminate the requirement to report on the production of each Bison wind farm in future RRR filings. The Company is confident that the Agreement negotiated with Oconto is good for customers in that it provides an additional credit to customers by selling renewable energy credits that would be otherwise retired. Further, approving the corrected allocator for allocating the costs for the Bison 6 LGIA related property credits customers the fair amount for ACE's use of the facilities and is the right thing to do.

Dated: February 14, 2020

Yours truly,

Lori Hoyum
*Regulatory Compliance Administrator*

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

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Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 14th day of February, 2020, she served Minnesota Power's Reply Comments in **Docket No. E015/M-19-523** on the Minnesota Public Utilities Commission and the Energy Resources Division via electronic filing. The persons on Minnesota Power's General Service List attached were served as requested.

______________________________
Tiana Heger