minnesota power
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September 7, 2022

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 Application for Approval of its 2021-2035 Integrated Resource Plan
Docket No. E015/RP-21-33
Corrected Reply Comments

Dear Mr. Seuffert:

Minnesota Power (or "the Company") submits corrected version of the Company's Reply Comments in its Integrated Resource Plan ("IRP") filed with the Minnesota Public Utilities Commission ("Commission") on August 29, 2022. It was brought to Minnesota Power's attention by the Clean Energy Organizations ("CEOs") that the following statement on page 49 of the Company's Reply Comments was not accurate: *"This was because the CEOs removed gas generation as a resource alternative to be selected."*

In Minnesota Power's initial review of the CEO's modeling it appeared new natural gas was not allowed to be selected. Under further review of the modeling and comments, Minnesota Power agrees that the CEOs did allow natural gas resources to be selected in the capacity expansion plan models they provided Minnesota Power for the high carbon and high environmental value scenario.

The Company apologizes for the unintentional misrepresentation of the CEO's analysis and submits the accompanying corrected version of the Company's Reply Comments which removes the sentence referenced above.

If you have any questions regarding this filing, please contact me at (218) 355-3202 or jjcady@mnpower.com.

Respectfully,

Jennifer Jae Cady
Director – Regulatory Affairs

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan	Docket No. E015/RP-21-33 **CORRECTED REPLY COMMENTS**

EXECUTIVE SUMMARY

Minnesota Power has put forward a long term resource plan for its customers that is realistic, thoughtful and balanced while making meaningful progress to continue its clean energy transition. While other Parties have the ability to be singularly focused on specific issues – whether it be economic modeling, customer ratepayer impacts or environmental concerns – Minnesota Power has a solemn obligation, and privilege, to serve its customers and consider a multitude of factors when planning to meet those customers' energy needs into the future. The Company has proposed a path and pace to its continued clean energy transition that accounts for a just transition for employees and communities in northern Minnesota that mitigates severe rate impacts to customers, helps ensure a reliable system to meet energy needs and makes significant reductions in carbon emissions along with renewable energy additions.

Minnesota Power has led the State of Minnesota in decarbonizing its system, taking a utility whose generation portfolio was 95 percent coal-based in 2005 to one that was the first in the state to be 50 percent renewable. The Company has made that transition while keeping rates among the most affordable in the state and offering innovative programs to help customers conserve energy and access renewable energy. Minnesota Power's Preferred Plan – informed by an inclusive, robust stakeholder process and filed in February of 2021 - details a sustainable transition that results in a portfolio that is 80 percent carbon free in 2035 with no coal fired generation on the system, and outlines a vision for the Company to be 100 percent carbon free by 2050.

Technology, public policy, regulation and the energy industry as a whole continue to experience a high rate of change. Minnesota Power is pacing with these changes, many of which have occurred in the 18 months since the Company's Integrated Resource Plan

(“IRP”) was filed. Minnesota Power looks forward to the Commission to resolving this pending IRP and implementing the next phases of the Company’s transformation.

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I. INTRODUCTION

Minnesota Power (or the "Company") submits these Reply Comments to the Minnesota Public Utilities Commission ("Commission") in response to the Department of Commerce – Division of Energy Resources ("Department"), Clean Energy Organizations ("CEOs"), Large Power Intervenors ("LPI"), Citizen's Utility Board ("CUB"), Office of the Attorney General ("OAG"), and others who filed Initial Comments on April 29, 2022, and those who filed Supplemental Comments on July 29, 2022. In these Reply Comments, Minnesota Power explains why the Company's Preferred Plan – also known as the "2021 Plan" – is holistically the best outcome for customers, provides an update on the status of the short term action plan, and responds to parties Initial Comments regarding in its Integrated Resource Plan ("IRP").

As background, Minnesota Power was proud to submit this IRP that outlined the next chapter in the Company's Energy*Forward* resource strategy. Energy*Forward* has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering 50 percent renewable energy to customers. The 2021 Plan advances Minnesota Power's vision for a sustainable carbon-free energy future by 2050, and outlines bold next steps in the clean energy transition that are centered on a commitment to the climate, customers, and communities.

The 2021 Plan was also informed by a first-of-its kind stakeholder engagement process and, if approved will result in a generation mix that is coal-free by 2035 while providing safe, reliable and affordable power for Minnesota Power customers and a just transition for the Boswell Energy Center ("BEC" or "Boswell") employees and host community.

Specifically, Minnesota Power's Preferred Plan includes the following action steps in the Long Term Plan (2026-2035) to achieve a power supply that is 70 percent renewable in 2030 and reduce carbon emissions 80 percent by 2035:

- Retire the Boswell Energy Center Unit 3 by December 31, 2029;
- Add 200 MW of solar that leverages the Boswell site or other Minnesota Power facilities by 2030, leveraging existing interconnections and reinvesting in utility host communities;
- Work collaboratively with customers to pursue up to 50 MW of long-term demand response by 2030 to address future resource adequacy changes;
- Develop and implement transmission solutions to address reliability issues related to the early retirement of Boswell Unit 3; and
- Investigate options to refuel or remission Boswell Unit 4 and associated reliability transmission as coal operations cease by 2035.

On February 3, 2021, the Commission issued a Notice of Comment Period on the following topics:

1. Should the Commission approve, modify, or reject Minnesota Power's 2021 Integrated Resource Plan (IRP)?
2. When should Minnesota Power file its next IRP? What additional information should the Commission require Minnesota Power to provide as part of its next IRP?
3. Are there other issues or concerns related to this matter?

Minnesota Power appreciates the time and work by all Parties to develop Initial Comments and Supplemental Comments that convey their respective viewpoints. Through these Reply Comments, Minnesota Power provides further justification for why the 2021 Plan is holistically the most appropriate outcome in this proceeding. Minnesota Power believes its 2021 Plan will continue to serve its customers in a thoughtful and forward-looking way during the 2021-2035 planning period, and presents a plan that reflects its commitment to its customers, communities, and the climate.

II. MINNESOTA POWER'S PREFERRED PLAN REMAINS THE MOST REASONABLE PLAN FOR CUSTOMERS, COMMUNITIES AND THE CLIMATE

Minnesota Power's Energy*Forward* strategy is effectuated through a holistically sustainable resource plan for its customers, the climate and the communities it serves. The Company's 2021 Plan outlines a reasonable pace and path that takes significant action to benefit the climate through state-leading renewable energy additions and carbon reduction, while also ensuring a reliable and resilient system to serve customers.

Much has changed in the 18 months since Minnesota Power initially submitted its IRP in February 2021, but the Company is confident that its Preferred Plan remains the best path when considering current market conditions, the energy policy of the State of Minnesota, and reflects the results of an extensive stakeholder engagement process.

a. Current Market Conditions Support Minnesota Power's Plan

Minnesota Power has been advancing a transformation of its power supply to a cleaner energy future through its Energy*Forward* strategy since 2010. As part of this transition, Minnesota Power has either retired, idled, or remissioned seven of its nine coal-fired generating units. Minnesota Power currently has two dispatchable coal-fired baseload units at BEC, two dispatchable renewable biomass units at Hibbard Energy Center ("Hibbard"), and two dispatchable natural gas fired peaking units at Laskin Energy Center ("Laskin"). The dispatchable generation fleet means generation is available to serve customer load when renewable energy is not available or there is not enough energy to serve customer load. This section will discuss current market conditions as they relate to Minnesota Power's Plan.

Minnesota Power participates in the annual Midcontinent Independent System Operator ("MISO") Planning Reserve Auction ("PRA") process, which helps ensure there is adequate capacity to serve customers' needs through the MISO Resource Planning Auction. Because of the Company's prudent planning, Minnesota Power has enough resources to meet its Planning Reserve Margin Requirement ("PRMR") and is resource adequate for the Planning Year 2022-2023. MISO's capacity auction cleared at the Cost of New Entry ("CONE") for the entire North/Central regions for the first time in the Planning Year 2022-2023, signaling a change in the overall regional power supply balance. MISO has indicated that the capacity shortfall is due to the decrease in accredited capacity, driven by thermal retirements and the increasing transition to renewable resources. "Year over year comparison reflects the industry's ongoing shift away from coal-fired generation and an increasing reliance on gas-fired resources and non-traditional resources."[1] Minnesota Power's Preferred Plan is an orderly transition that helps ensure capacity and energy at Boswell is maintained through this critical planning period.

MISO has also indicated through its Summer Readiness Workshop[2] that the summer of 2022 is forecasted to be the sixth hottest summer on record nationally with above normal temperatures and potentially active storm patterns across MISO North/Central regions. Minnesota Power's Preferred Plan positions the Company to successfully navigate extreme weather events. Through the combination of adding new renewable resources and keeping Minnesota Power's dispatchable fleet available until carbon free technologies advance and adequate replacement for energy and capacity can be implemented, the Company will retain the energy attributes needed to uphold reliability until it is better understood what technology and replacement sources can provide for a carbon free future.

Minnesota Power actively participates in MISO emergency drills, including simulating a firm load shed event for Minnesota Power system operators to help ensure preparedness. The Company also routinely plans its scheduled maintenance to align generation and transmission resources are available during MISO peak load expectations. Through these actions and its Preferred Plan, Minnesota Power is well prepared for the upcoming summer and winter seasons.

Minnesota Power also expects market prices to remain high through the remainder of 2022 and winter of 2023. Natural gas prices, which tend to be a leading indicator in energy market pricing, have been extremely volatile in 2022 averaging $5.68/MMBtu and ranging

[1] https://cdn.misoenergy.org/20220525%20RASC%20Item%2004d%20PRA%20Detail624732.pdf
[2] https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf

from $3.73/MMBtu to $9.44/MMBtu at Henry Hub. The volatility in natural gas pricing has carried over to the energy markets as regional energy prices have averaged approximately $49/MWh for January – July 2022; a 40 percent increase compared to the same timeframe in 2021. The high market prices are expected to remain for the balance of 2022 and into the winter of 2023. For comparison, BEC's average costs are **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**, which is below the market expectations and provides significant benefit to Minnesota Power's customers. Minnesota Power's current peaking generating units, which consist of Laskin Energy Center and Hibbard Renewable Energy Center, have also operated significantly more frequently (over 138 percent) in 2022 as compared to 2021 due to higher market prices and system reliability requirements in the Minnesota Power region.

Congestion cost has increased significantly from September 2021 to May 2022. Ongoing Mitigation efforts by the Company have included utilizing the Financial Transmission Rights ("FTR") from the seasonal and monthly markets and to investigate the cause of the congestion using reported Binding Constraints as reported by MISO. Transmission Mitigation efforts include reviewing the ratings of critical facilities driving the congestion, and determining what other cost-effective system improvements should be considered. The MISO Long Range Transmission Plan ("LRTP") is also expected to provide congestion relief as a long-term solution in the MISO North region.

In conclusion, current market conditions, which include MISO's indicated capacity shortfall, increased extreme weather events, natural gas prices and transmission congestion, all reinforce Minnesota Power's Preferred Plan as the responsible path to help ensure reliability for customers in northern Minnesota.

b. Energy Policy of the State of Minnesota is Reflected in Minnesota Power's Preferred Plan

The State of Minnesota has a number of energy policy objectives codified in state statute. Energy policy goals related to the climate include Greenhouse Gas Emissions reduction targets, renewable energy standards — including a solar energy standard — and energy conservation goals, including the recently passed Energy Savings and Optimization

Policy Goal. State policy guidance related to customers includes regulation to assure reliable electric service at just and reasonable rates. The state goals above, and those found in statute but not listed here, are also Minnesota Power's shared goals. The Company has been pursuing and achieving State energy policy goals for many years – most recently through the Company's Energy*Forward* strategy – and Minnesota Power's Preferred Plan recognizes, balances and supports these many state energy policy directives.

Considering Host Community Transition

Minnesota Power has served northern Minnesota for over a century and is embedded in the communities in which it serves. The Company has considered a just transition for its employees and communities in northern Minnesota through its Preferred Plan, which includes a thoughtful pace and path of transition away from coal for its only remaining baseload facility, BEC. While the Company specifically considered the impacts of its Plan to the community that has hosted BEC for decades, other Parties in this docket did not. While consideration of host community impacts is the energy policy of the state, other intervenors are not required to and did not consider those impacts in their recommendations. This section will outline the importance of host community transition as a public policy consideration in the State of Minnesota and should be taken into account when considering different options for Minnesota Power's IRP.

The Company designed and implemented a first-of-its-kind stakeholder process[3] to help inform the development and outcomes of this IRP, and intentionally ensured host community representatives whose voices are not always heard at the Commission were included in this process. This stakeholder process began in the fall of 2019 and continued through the COVID-19 pandemic in 2020.

The Company's 2021 Plan helps ensure a just transition for BEC's host community, which is the smallest and most geographically isolated coal plant host community in the State of Minnesota. The Commission should adopt the Company's proposed timeline for BEC

[3] The Stakeholder Engagement Report is Appendix R in the Company's IRP, filed in this docket on February 1, 2021.

to create certainty to provide both employees and the community the necessary time to plan for a future beyond coal operations, while reinforcing the importance of leveraging existing infrastructure for the future.

The importance of host communities is evidenced in part by the actions of the Midwest Governor's Association ("MGA"). MGA, under the leadership of Minnesota Governor Tim Walz, identified preparing Midwestern communities who host power plants for future transition as a focal point of MGA's agenda. In 2021 Governor Walz initiated a multi-year effort, called "Empowering Midwestern Communities." MGA notes,

> *"Participants have been charged with scoping out the problem of closures, developing solutions to the problems, and developing plans to support these effected communities and their workforce. Since these generation facilities are often the communities' largest employer, the loss to the community is large in terms of jobs, but also ancillary business."*[4]

Another example of the importance of host community transition in Minnesota's state energy policy is the creation of the Energy Transition Office within the Minnesota Department of Employment and Economic Development. The Energy Transition Office was created in 2021 by the legislature through Minn. Stat. § 116J.5491. The Energy Transition Advisory Committee includes 18 voting members, some of which represent entities impacted by the closure of power plants in Minnesota Powers service territory.

While considering the input of and impacts on the employees and communities that have hosted generation that has powered homes and businesses for decades is simply the right thing to do, it is also enshrined in Minnesota's state energy policy in both Minnesota law and Governor Walz's work through MGA. Host community transition needs to be a consideration of the Commission as it evaluates Minnesota Power's current IRP.

[4] https://midwesterngovernors.org/power-plant-closures/

Considering Affordability of Electricity

While evaluating different possible scenarios throughout the IRP process, Minnesota Power considered the rate impact to customers and its Preferred Plan is the least cost option available to customers today that continues a transition away from coal fired generation. The Company recognizes the cost impact associated with the investments that have taken its system from 95 percent coal to 50 percent renewable today, and has proposed a pace and path of future investment and carbon reduction efforts that keeps affordability for customers front of mind.

Minnesota Power's rates are competitive among all utilities across the nation, especially considering the significant amount of decarbonization that has taken place in Minnesota Power's energy supply since 2005. According to the United States Energy Information Administration ("EIA"), Minnesota Power's residential customers paid approximately 15 percent less than the national average in 2020, and its industrial customers paid approximately five percent more than the national average while receiving a power supply that was 50 percent renewable, well ahead of others.[5]

Minnesota Power has taken several proactive steps to keep customer rates reasonable and competitive. These actions include, but are not limited to, settling the 2019 Rate Case in the midst of the COVID-19 pandemic, the approved extension of the EITE rate for large power customers, the inclusion of a low-income usage qualified discount as the Company transitions from the current Inverted Block Rate structure to a future default Time-of-Day rate for residential customers, and voluntarily offering to sell lands traditionally associated with hydroelectric operations for rate mitigation purposes. Taken together, these actions represent a holistic, creative, and forward-looking approach to mitigating rate increases and protecting customers as Minnesota Power continued its clean energy transition in the midst of a global pandemic. However, while mitigating the impacts of investments made to achieve a power supply that is half renewable is important, charting a long term strategy

[5] Minn. Docket No. E015/GR-21-335. Rate Case Overview Direct Testimony by Witness Jennifer Cady.

that helps ensure the most affordable path to decarbonization is equally critical, and Minnesota Power's Preferred Plan is the least cost option for customers today.

Clean Energy and Environmental Leadership

Minnesota Power has a history of excellence in environmental stewardship that has contributed to the state's overall track record of leadership on environmental issues. Strong performance has been achieved through the installation of timely, cost-effective environmental controls and new energy resources that balance customers' needs for reliable and affordable energy while advancing a carbon-free future. As a core value of the Company, Minnesota Power balances the environmental impacts of its activities with its obligation to customers, communities, shareholders, and future generations.

At the end of 2020 Minnesota Power began providing over 50 percent renewable energy to customers – the first utility in the state to do so. Additionally, the Company has reduced NOx emissions by 87 percent and SO2 emissions by 98 percent since 2005. Mercury emissions have also collectively decreased by 95 percent in the Company's thermal fleet as compared to 2005 emissions. Minnesota Power demonstrates its values with the actions it takes each day while providing the reliable electric supply its customers deserve and rely upon.

Through its 2021 IRP, Minnesota Power outlined a bold vision to achieve a carbon-free power supply by 2050. As important, is *how* the Company achieves that vision – it must be sustainable and affordable for customers. While it is the most affordable plan for customers, Minnesota Power's 2021 Plan also makes meaningful progress in decarbonizing the system and exceeds both Minnesota's current greenhouse gas emissions-reduction goal in state statute and the Paris Climate Accord targets for greenhouse gas reductions.

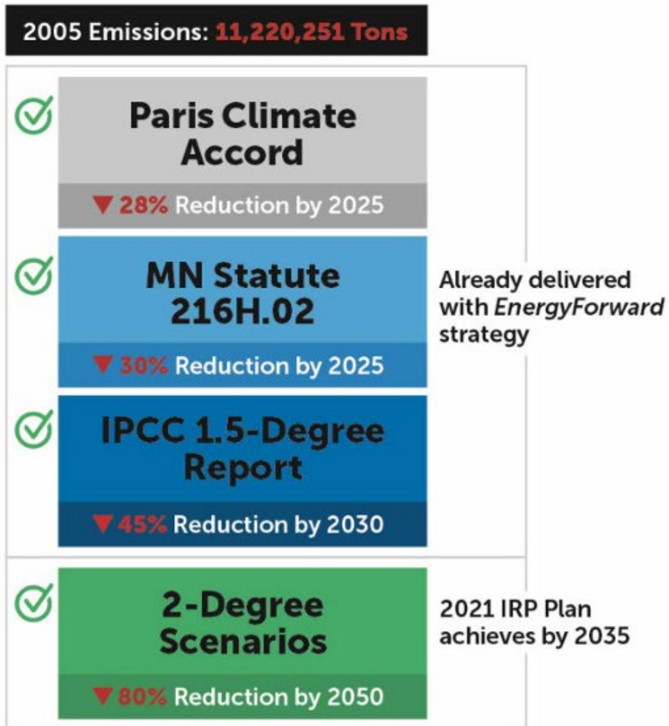

Figure 1. Minnesota Power's Progress on Reducing Carbon Emissions

c. Minnesota Power's Plan is Reflective of Extensive and Inclusive Stakeholder Engagement

Minnesota Power's first-of-its-kind stakeholder process brought diverse groups together to share insights and engaged host community members not normally represented at the Commission. Over 70 stakeholders representing various customer groups, environmental organizations, economic development entities, local government, industry, and the host communities participated. Stakeholders were asked to identify and define the issues they cared about most, including what a "best case" and "worst case" future situation might look like for each issue area. These issues were captured in an innovative Issue Map that identified metrics within four broad categories: customers, host communities, the environment, and the grid.

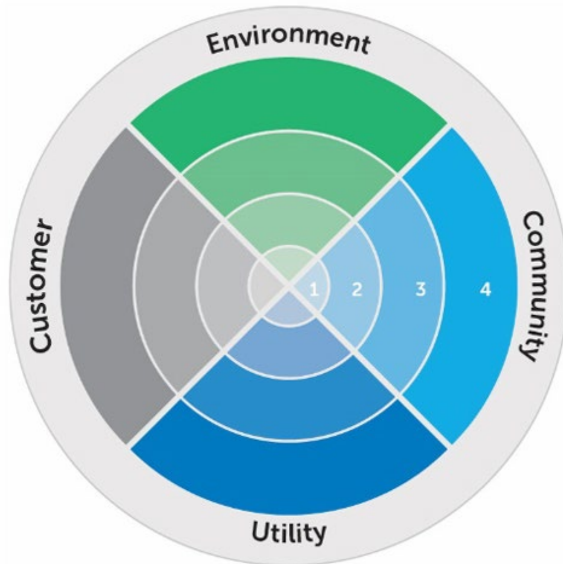

Figure 2. Stakeholder Issue Map

The input from the stakeholder process directly informed the development and outcome of Minnesota Power's Preferred Plan, which balances meaningful action on climate, keeping rates affordable for customers, maintaining system reliability and ensuring a just transition for host communities. Since filing the 2021 IRP, Minnesota Power has continued to work with and update stakeholders as the regulatory process proceeds. While other Parties in this proceeding may favor one aspect of the stakeholder issue map over another, Minnesota Power's Plan is truly a balanced consensus-based plan considering multiple perspectives important to its customers and stakeholders.

III. MINNESOTA POWER'S SHORT TERM ACTION PLAN IS ALREADY UNDERWAY

As stated previously, Minnesota Power has led the State in reducing carbon emissions and has transitioned from relying almost entirely upon coal-fired generation to being the first Minnesota utility to deliver a power supply that is 50 percent renewable in just 15 years. While the Company has made tremendous strides in its clean-energy transformation, it recognizes there is more work to do. Through this IRP, Minnesota Power has committed to achieve an 80 percent reduction in carbon emissions by 2035 compared to 2005 levels, and outlined a goal of delivering 100 percent carbon-free energy by 2050. The Company's Short Term Action Plan[6] outlined steps Minnesota Power would take to reduce carbon emissions in the near term and continue the addition of renewable energy, conservation and other demand side resources to the Company's power supply portfolio.

While this Docket has been pending Minnesota Power has continued to move forward to add renewable energy to its portfolio, conserve energy, and reduce carbon. The Company continues to pursue the short term actions outlined in the initial IRP filing. Updates on the specific strategic and necessary short term actions outlined in the IRP include:

- At this time, Taconite Harbor Energy Center Units 1 and 2 are not retired. The Company is waiting for the Commission to take action on its request to retire the remaining two units. In its 2021 rate case and 2022 Remaining Life Depreciation Petition, Minnesota Power is requesting recovery of depreciation of the facility through December, 2026, its currently approved end of life;[7]
- Construction of three solar projects totaling approximately 22 MW in the Company's service territory in 2022 was approved by the Commission. The projects meet both Minnesota Power's requirements under the Solar Energy Standard and assist in the local economic recovery from the COVID-19 pandemic.[8] The projects are include 5.6 megawatts at the Laskin Energy Park

[6] Page 14 of Minnesota Power's Integrated Resource Plan.
[7] Docket No. E015/D-22-433 & Docket No. E015/GR-21-335.
[8] Docket No. E015/M-20-828 & Docket No. E, G-999/CI-20-492.

near Hoyt Lakes, Minnesota, 15.2 megawatts near Minnesota Power's Sylvan Hydro Station, west of Brainerd, Minnesota, and 1.6 megawatts in the city of Duluth, Minnesota. Construction on the projects began in late 2021 at the Duluth site and early 2022 at the Sylvan and Laskin sites. The expected in-service date for the Duluth and Laskin projects is December 2022, while the Sylvan project may be delayed into 2023. The projects have been developed with a focus on supplier diversity, use of locally manufactured solar panels and local labor for construction. The projects have already had impacts to the local economy, with over $22 million in contracts being awarded to local or regional suppliers and contractors as of July 2022;

- In 2021, operations at BEC Unit 3 (or "Boswell Unit 3") transitioned to economic dispatch within the MISO market. This change in operations provides the potential to reduce carbon emissions based on regional market activity while also supporting reliability in the region and continuing to provide economic benefits for the local host community;
- In coordination with MISO and BEC Unit 4 (or "Boswell Unit 4") joint owner WPPI Energy, the Company continues to monitor market prices and reliability impacts as it considers transition to future economic dispatch for BEC Unit 4;
- Minnesota Power continues its leadership in conservation programs and electrification efforts. The Company has surpassed the state's conservation goals for the last decade and identified ambitious energy savings goals in its 2021-2023 CIP Triennial Plan.[9] In the 2021 program year, the Company achieved energy savings of 2.8 percent of gross annual retail energy sales, well above the state's 1.5 percent energy-savings goal established in Minn. Stat. § 216B.241[10] and the 2.5 percent savings goal set in the 2015 IRP. The Company also continues to implement infrastructure investments, rate design changes and electric vehicle programs to position for a future grid that accommodates further electrification; and

[9] Docket No. E015/CIP-20-476.
[10] Docket Nos. E015/M-22-130, E015/CIP-20-476.01.

- In early January 2021, Minnesota Power submitted a petition requesting Commission approval of eight multi-year Demand Response ("DR") Product C agreements with industrial customers that will collectively enable between 100 and 202 MW of DR product to be sold each year from 2022 to 2028. In September 2021, the Commission approved the DR Product C agreements as a six-year pilot program. Implementation began on June 1, 2022.

IV. MINNESOTA POWER'S REPLY COMMENTS

This section of Minnesota Power's Reply Comments will address several key issues raised in initial comments, including: reliability in system planning, the role of the Nemadji Trail Energy Center ("NTEC") in this Plan, the Department's "FastExit" scenario, recommendations to acquire 600 MW of solar by 2025, comments regarding whitewater kayaking opportunities around the Thomson Dam, the Health Equity Study, and a response to the OAG's assessment of forecasting accuracy.

a. Reliability Remains a Foundational Pillar of Minnesota Power's System Planning

While other Parties in this docket provide analysis on specific aspects of long term resource planning, it is the utility's solemn obligation to provide reliable electric service for all customers, and Minn. Stat. § 216B.01 the Minnesota Legislature declared that public utilities are required to provide reliable service at reasonable rates. Minnesota Power takes that obligation seriously always, but particularly as the industry continues to evolve at a high rate of change and reliability is impacted by resource transitions and increased extreme weather. Minnesota Power's Preferred Plan provides a pathway for reliable service for customers at a reasonable rate. The following section discusses the current state of reliability in the MISO region, the evolving needs of the system with the energy transition, how the Company's 2021 Plan addresses resource adequacy needs, and outlines how Minnesota Power is considering resource adequacy in future IRP proceedings.

Since the filing of Minnesota Power's 2021 Plan, the MISO Planning Year 2022-2023 Planning Resource Auction cleared at CONE ($236.66/MW-Day) for all resource zones in MISO Central and MISO North. The prior Planning Year cleared at $5/MW-Day, 98 percent lower than Planning Year 2022-2023. There was an accredited capacity shortfall of 1,230 MW driven by a limited amount of capacity in the MISO South to MISO Central transmission interface. This milestone of a capacity shortfall is the result of many aspects of resource adequacy including the continued resource transformation with the retirement of baseload coal generation by many load serving entities and an inadequate amount of accredited resources to replace the retirements.

Following this activity in the MISO resource adequacy auction, the June 10, 2022 MISO Organization of MISO States ("OMS") survey results predicts a capacity shortfall up to 2,600 MW of accredited capacity in Planning Year 2023-24 for the overall MISO footprint (Note this capacity deficit is restricted to MISO North/Central) and increasing in the level of capacity shortfall through to the last reported year of 2027-28 of over 10,900 MW.[11] The MISO OMS survey is considered an indication of the system capacity outlook based on a number of data sources and assumptions, but is the most comprehensive means of showing the MISO resource adequacy outlook beyond one year. The MISO OMS survey includes an assessment of the capacity balance by Local Resource Zone ("LRZ"). Minnesota Power is in MISO LRZ 1 and monitors the capacity balance using the OMS survey. For Planning Year 2023-2024, LRZ 1 identified a surplus of up to ~2000 MW. As referenced by MISO and OMS, the LRZ 1 surplus does not alleviate CONE clearing prices for MISO North Zones because of the defined methodology on establishing the MISO North and Central PRA clearing price. The resource adequacy short falls in these reports identify that reliability targets are not being met with the current near term plans collectively in MISO and close attention to pace and path needs to be considered.

Also part of the changing landscape is the MISO's Resource Availability and Need ("RAN") initiative, MISO filed a proposed change to the current annual Resource Adequacy methodology with the Federal Energy Regulatory Commission ("FERC") on November 1, 2021 (FERC Dockets ER22-495 and ER22-496). The revised method being considered is a Seasonal Accredited Capacity ("SAC"). MISO states in the Resource Adequacy Conceptual Design DRAFT dated August 16, 2021, "…the proposed enhancements will create better availability, flexibility, and visibility of resources to meet MISO's changing system needs."[12] FERC is expected to issue a ruling before the proposed implementation date of September 1, 2022. The proposed resource adequacy

[11] https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf
[12] https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20Seasonal%20RA%20Conceptual%20Design585538.pdf

construct includes provisions to establish a seasonal accredited capacity requirement as well as a means to incentivize dispatchable generation to be available during hours of tight operating margins. Initial indications of the methodology showed **[TRADE SECRECT DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** of Minnesota Power's dispatchable resources. The expected impacts of this on Minnesota Power's resource portfolio is not fully understood at this time, as the most current resource specific data will not be available until December 15, 2022. The proposed resource adequacy construct is not expected to relieve the OMS and MISO concerns about the current MISO capacity outlook, however, will be a critical requirement that will need to be managed for Minnesota Power's customers.

Electric System Reliability measures are evolving along with the changes in the power supply, and the evaluation of individual Load Serving Entity ("LSE") electric system reliability are increasingly complex because of the intersection of the concept of sharing planning reserves, so each LSE can cost-effectively provide for its own requirements, while also providing a share of requirements in conjunction with other LSEs for overall Balancing Authority (MISO level) reliability. There is a significant challenge of defining the impact of tight margin hours (RA Hours) in an IRP. Recent history is demonstrating an increasing number of MISO GenMax alerts and RA Hours, but there is significant complexity in determining the impacts of these hours on a company's resource portfolio and integration into a resource planning type model; this is something Minnesota Power will be reviewing for its next IRP submittal.

MISO has the highest level of sophistication in operating the electric system, and this clearly provides a means of developing more sophisticated metrics and analytics to maintain system reliability into the future. However, currently there is not a clear path of evaluating system reliability beyond the basic approach of showing a projection of adequate capacity to cover the peak demand and planning reserves. Future resource plans must contemplate a range of reliability metrics that go beyond the current measures.

A core focus in this IRP, in addition to the Boswell baseload retirement study, was the on-boarding of the EnCompass model. On-boarding new planning software is a significant process that includes learning, implementation, development of post processing tools, and evaluating unanticipated modeling results to help ensure robust and accurate IRP modeling. For the reasons discussed in the section above, Minnesota Power is anticipating a key focus in the next IRP will be developing reliability metrics and augmenting the traditional planning process to help ensure the next phase in Minnesota Power's Energy*Forward* strategy is reliable, flexible, sustainable, and cost effective for all customers.

b. Nemadji Trail Energy Center Remains in Minnesota Power's Base Case as an Approved Resource

NTEC is an approved resource in Minnesota Power's base case. NTEC was first approved by the Commission on January 24, 2019.[13] The Commission's 2019 Order approving NTEC was appealed and on April 21, 2021 the Minnesota Supreme Court affirmed the Commission's decision on the application of Minnesota Environmental Policy Act ("MEPA"). On August 23, 2021 the Minnesota Court of Appeals further affirmed the Commission's approval of NTEC. Since NTEC is to be sited in Superior, Wisconsin, NTEC continues progressing through Wisconsin regulatory and legal proceedings, receiving a Certificate of Public Convenience and Necessity ("CPCN") approval from the Public Service Commission of Wisconsin in January 2020. NTEC has also received a number of permits from the Wisconsin Department of Natural Resources thus far. However, despite the Commission's approval being upheld through reconsideration and legal appeals, and MISO's warnings of a future capacity shortfall, Parties in this docket are recommending the Commission rescind the approval of the NTEC resource.

Legal Considerations

After a full contested case, Minnesota Power received approval from the Commission in 2019 to purchase 50 percent of the output from NTEC as in the public interest under Minn.

[13] Docket No. E015/M-17-568

Stat. § 216B.48 with additional conditions, including two items for the current IRP: (1) a baseload retirement study for Boswell Energy Center Units 3 and 4; and (2) a securitization plan.[14] Subsequently, the Commission's decisions were appealed. The Minnesota Supreme Court reversed the Minnesota Court of Appeals and agreed with the Commission that the MEPA did not apply to a plant to be built in Wisconsin.[15] As the Court of Appeals stated: the "Minnesota Supreme Court reversed our decision and remanded for us to address MCEA's remaining challenge—whether the commission's approval of the affiliated-interest agreements "was supported by substantial evidence."[16]

The Court of Appeals affirmed the MPUC's decision to approve NTEC stating:

> *The commission explained that the EnergyForward package, including NTEC and the new wind and solar resources, moves Minnesota Power's resource plan increasingly toward renewable resources and away from the coal resources that are "the biggest obstacle to Minnesota Power achieving state emission-reduction goals in the long term." The commission also discussed the greater reliability NTEC provides, as opposed to wind or solar alternatives, and the costs that Minnesota Power would incur if it added still more of those intermittent resources instead of NTEC. And the commission emphasized the role NTEC can play in supporting an overall more diverse, environmentally conscious, and lower-cost portfolio of resources.*
>
> *The record, including to a limited extent the input the commission received at its two-day hearing, supports the conclusion that NTEC serves the public interest better than renewable-resource alternatives. As discussed above, Minnesota Power and the department offered extensive evidence and analyses showing that the transition away from coal and toward intermittent renewable resources impairs reliability and could increase reliance on energy markets, thereby increasing costs.*

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[14] As the Minnesota Court of Appeals noted: "the commission crafted a unique standard for assessing the NTEC affiliated-interest agreements that incorporates (1) a "need" requirement and (2) the "renewable resource requirements" of the certificate-of-need and resource-planning statutes."
Matter of Minnesota Power's Petition for Approval of EnergyForward Res. Package, No. A19-0688, 2021 WL 3716404, at *4 (Minn. Ct. App. Aug. 23, 2021)
[15] *In re Minn. Power's Petition,* 958 N.W.2d 339 (Minn. 2021).
[16] *In re Minn. Power's Petition*, 958 N.W.2d 339, 350 (Minn. 2021).

> *Their analyses also demonstrated that NTEC addresses these concerns, providing a more reliable and lower cost (including environmental costs) source of energy than the equivalent renewable resources. Accordingly, substantial evidence supports the commission's determination that NTEC best serves the public interest.*[17]

Minnesota Power relied on these decisions in including 50 percent of NTEC's output in its IRP filed on February 1, 2021. Parties argue that the Commission should reconsider its decision as part of this IRP. Minnesota Power recognizes the Commission has the right to reconsider decisions on its own motion at any time under Minn. Stat. § 216B.25; however, to do so as part of an IRP would negate the regulatory certainty that comes from Commission decisions and that are relied upon in future planning.

In addition, state and federal courts have cautioned agencies from departing from agency precedents. The Minnesota Supreme Court has adopted the following standard developed by federal courts:

> *We find the standard developed by the federal courts to be persuasive. When an agency seeks to deviate from its prior decisions, the agency is charged with setting forth a reasoned analysis for the change. Sierra Club v. Clark, 755 F.2d 608, 619 (8th Cir.1985). If a reasoned explanation is provided, the courts then review that explanation to determine whether the explanation was arbitrary and capricious. Id. Accordingly, we conclude that an agency must generally conform to its prior norms and decisions or, to the extent that it departs from its prior norms and decisions, the agency must set forth a reasoned analysis for the departure that is not arbitrary and capricious. See id.*[18]

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[17] *Matter of Minnesota Power's Petition for Approval of EnergyForward Res. Package*, No. A19-0688, 2021 WL 3716404, at *6 (Minn. Ct. App. Aug. 23, 2021)
[18] *In re Rev. of 2005 Ann. Automatic Adjustment of Charges for All Elec. & Gas Utilities*, 768 N.W.2d 112, 120 (Minn. 2009)

Resource Planning Considerations

NTEC is a valuable dispatchable resource that can provide energy when renewable resources are unavailable. Regardless of whether the system experiences a three day wind drought or solar panels are covered with snow for several days, NTEC has the capability to generate energy and maintain reliability throughout that entire period. It is not constrained by available surplus energy to charge a battery and energy production is not limited by the number of hours of storage available, it can provide energy to the system to help ensure reliability. Furthermore, NTEC is being developed with state of the art technology that can pivot to burn hydrogen or add carbon capture at a future date, reducing the stranded asset risk for customers. Minnesota Power recognizes that the cost to convert NTEC to burn hydrogen or the cost to add carbon capture was not incorporated into prior modeling. However, having the optionality for future modification so that NTEC can continue to serve customers' energy needs in a future carbon free power supply is an important consideration.

Minnesota Power recognizes that demand outlooks change and there are conditions that potentially warrant a change in plans. Therefore, the Company is continually adapting to its latest landscape and customer energy requirements. Since Minnesota Power filed the NTEC petition there have been changes in industrial customer demand, especially in the paper and taconite industry following the COVID-19 pandemic, that are captured in the Company's latest customer outlooks.

On September 28, 2021, South Shore Energy, the Wisconsin subsidiary of Minnesota Power, announced that it had sold part of its interest in NTEC to Basin Electric Cooperative. Basin Electric will become a 30 percent owner in the facility and South Shore Energy will retain a 20 percent energy and capacity off-take from NTEC, down from the previous 50 percent. Dairyland Power Cooperative will continue to own 50 percent of NTEC.

Minnesota Power will submit an updated Capacity Dedication Agreement for Commission affiliate approval upon finalization of all Wisconsin and federal permits that will allow the project to proceed. Until that occurs, Minnesota Power asserts no further Commission action is needed within this planning docket. With the change, NTEC represents less than 5 percent of Minnesota Power's total power supply portfolio but serves as an important future asset for balancing renewable energy additions and ensuring reliability. Furthermore, today Minnesota Power does not have any modern natural gas generation technology on its system. To reopen the NTEC decision would set a precedent encouraging parties to repeatedly request that the Commission reconsider resource decisions, despite being past the formal reconsideration period and following legal challenges that have since been resolved.

Prior to 2030, Minnesota Power does not anticipate any material impacts to the 2021 Plan with the Company's reduced share of NTEC's output. Post 2030, after Boswell Unit 3 is retired off of coal, there could be energy and capacity requirements that will need to be addressed, depending on a number of factors. The Company expects to provide a detailed replacement plan for both BEC units in its next IRP, as there is sufficient time to address the post 2030 needs with a smaller share of NTEC in the next IRP given the requirement to file an IRP approximately every two years.

In the CEO's modeling, NTEC was removed and replaced with solar in 2026. The CEO's also had storage included in their Preferred Plan starting in 2030, but it was not clear in their analysis if that storage was tied to replacing NTEC or to the 350 MW retired at Boswell Unit 3 in 2029. Minnesota Power believes energy storage will have a role in a carbon free power supply, especially when it comes to balancing the variability of wind and solar production. Promising long duration storage technology like flow batteries can help mitigate the need to maintain reliable service and this is a developing area Minnesota Power continues to watch. However, these promising technologies do not replace the need for NTEC in the Company's power supply portfolio.

In a letter submitted into the United States Department of Agriculture's Rural Utilities Service ("RUS") proceeding for project financing by Dairyland Power Cooperative on

July 25, 2022,[19] MISO stated that the RUS should consider that "the electric grid is undergoing significant fleet changes that creates an immediate need for stakeholders to work together to address and maintain electric reliability." Further, MISO states that with older generation resources retiring and are being replaced by renewables and other resources, that a "certain level of dispatchable and flexible resources are required for MISO to reliably manage the transition to a decarbonized energy future within its region."

MISO goes on to state "MISO currently faces declining levels of resource capacity which is challenging its ability to supply electricity to customers within the MISO Northern region…" Minnesota Power has refueled or retired 7 of their 9 coal facilities, but has added no dispatchable generation to its portfolio. All Minnesota Power's retired coal-based energy and capacity has been replaced with a mix of solar, wind, and hydro generation. The broader retirements of generation in MISO is occurring at a far faster rate than new energy sources being added that have equivalent attributes. NTEC not only addresses replacing some of the attributes lost on Minnesota Power's system with coal retirements, but also addresses a broader concern of attributes lost across MISO and the looming capacity shortfall of generation needed to help ensure grid reliability 365 days a year. Upon completion of this IRP, these and other reliability impacts will need to be considered in Minnesota Power's next IRP as it identifies what will replace coal fired energy in its portfolio.

Policy Considerations

The State of Minnesota, through Minn. Stat. § 216B.2422, subd. 4 has a clear preference for renewable energy additions unless the utility has demonstrated the renewable energy facility is not in the public interest. When making the public interest determination on a renewable preference, the Commission must consider impacts to regional grid reliability, among other things. On August 23, 2021, the Minnesota Court of Appeals upheld the Commission's approval of NTEC, noting that there was substantial record evidence

[19] Minnesota Power filed MISO's comments to the RUS in this Docket on August 5, 2022.

supporting the need for NTEC, and that NTEC was cost effective even when considering the renewable preference.[20]

The CEOs and the OAG recommend the Commission reconsider its approval of NTEC, even while the Department is arguing for Minnesota Power to add more than 800 MW of additional natural gas generating resources to its portfolio, in addition to the Company's portion of NTEC. While the CEOs argue that new fossil fuel infrastructure is incompatible with the State's carbon reduction goals, Minnesota Power's Plan clearly outlines the role NTEC plays in reducing carbon in its portfolio by facilitating the early retirement of BEC Unit 3 and the addition of more renewable energy resources.

Additionally, the Supplemental Environmental Assessment for the Nemadji Trail Energy Center Project stated that, "[T]he Project is expected to be one of the most efficient dispatchable facilities in MISO and its operation is expected to result in less coal generation in both MISO West and specifically in Dairyland and Minnesota Power service territories."[21] Also included in MISO's comments was a statement that, "Given the changes to the generating fleet, and the potential shortfalls in generating capacity, it is imperative that reliable generating resources, like those in the NTEC Project, be recognized for the regional reliability value provided to the region's customers."[22]

As the Commission has previously recognized, NTEC clearly plays a role in decarbonizing Minnesota Power's system by filling the need left by the retirement of seven of its nine coal-fired units and planning for the retirement of Boswell Unit 3 in 2029 – supporting Minnesota's carbon reduction goals. At the same time, a clear need is being articulated by MISO for dispatchable capacity to help ensure reliability, and reliability is enshrined through statute in Minnesota energy policy. Finally, NTEC is an approved resource in the base plan of Minnesota Power's 2021 Plan, which represents the least

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[20] "*MCEA argues that this conclusion lacks sufficient detail and evidentiary support. The Company disagrees. While the conclusion is concise, it nonetheless communicates the commission's reasoning—a wind or solar alternative is not in the public interest because the comprehensive costs for such resources are higher than those associated with NTEC. And its decision as a whole demonstrates that it considered the relevant factors and extensive evidence adduced during the contested case and before the commission in arriving at that conclusion*." *Matter of Minnesota Power's Petition for Approval of EnergyForward Res. Package,* No. A19-0688, 2021 WL 3716404, at *6 (Minn. Ct. App. Aug. 23, 2021)
[21] https://www.rd.usda.gov/resources/environmental-studies/assessment/nemadji-trail-energy-center-wisconsin
[22] Minnesota Power filed MISO's comments to the United States Department of Agriculture's Rural Utilities Services in this Docket on August 5, 2022.

cost plan for customers, further supporting Minnesota's energy policy of affordability of electricity for customers. In conclusion, in addition to legal precedent and resource planning considerations, NTEC remaining included in Minnesota Power's Plan supports the energy policy of the State of Minnesota.

c. Department's Conclusion to "FastExit" Boswell Energy Center are Unreasonable

The Department's conclusion that the "FastExit" from Boswell Energy Center is unreasonable for several reasons. First, a retirement of Boswell Unit 3 in 2025 is simply not feasible due to the significant impact of removing 350 MW of dispatchable generation at a time when MISO is experiencing capacity shortfalls and volatile energy markets. Furthermore, Minnesota Power submitted an Attachment Y-2 study request to MISO for a transmission system reliability assessment of various BEC retirement combinations. MISO concluded from the study that one or both of the BEC units could potentially be designated as a System Support Resource ("SSR") if transmission mitigation is not in place prior to retirement. Given the delays in this IRP proceeding, it is not feasible to engineer, permit, procure, and construct the transmission solutions in time for a Boswell Unit 3 retirement by 2025. In fact, the Minnesota regulatory processes alone for Certificate of Need and Route Permit approvals generally take at least twelve months to complete. Per MISO's Attachment Y process, Minnesota Power would need to enter into an agreement with MISO to keep the unit online as a SSR for the reliability of the regional transmission system. Once the transmission solutions are in place, MISO would allow Minnesota Power to move forward with retiring Boswell Unit 3.

Second, the Department's recommendation to replace Boswell Energy Center Units 3 and 4 with natural gas resources in a condensed timeline is neither realistic nor supportive of broader long term carbon reduction goals by recommending the addition of a significant amount of new natural gas generating resources. For an example of the timing it takes for new resources, NTEC was approved by the Commission in January 2019 and due to multiple and ongoing legal challenges in Minnesota and Wisconsin is not expected to be online until 2027. This does not take into consideration the original need for gas generation that came out of the Company's 2015 IRP. Nearly a 12 year timeline from new gas generation being identified as a need in an IRP and when it is expected to begin operations demonstrates the recommended addition of natural gas in just a few years is simply not feasible. Based on the NTEC timeline, it could be as late as 2035 when the gas generation needed to replace Boswell could be online if Commission approval was granted in this IRP proceeding. Given MISO's public statements about retirements occurring at a faster rate than resource additions being added with similar attributes, capacity shortfalls, and concerns of serving the energy needs of the region it would be reckless to retire Boswell Units 3 and 4 in anticipation that gas generation will be online or could be purchased in a shorter time period than what is experienced currently with NTEC.

Finally, the "FastExit" recommendations ignore significant considerations related to host community and employee transition, system reliability and customer rate impact that would occur under this recommendation.

d. Recommendations to Acquire 600 MW of Solar by 2025 are Not Practical

The Company acknowledges more solar energy additions are in the public interest for this resource plan, and has proposed 200 MW of new solar additions in its Preferred Plan by 2030. However, the Commission must consider the need for much higher solar additions, with the reliability needs on the system emerging, the realities of supply chain challenges and the cost impacts to customers of acquiring more solar by 2025, as discussed earlier in these Reply Comments.

The impacts of the COVID-19 pandemic continue to be experienced through supply chain challenges across the industry the MISO interconnection queue backlog are both resulting in challenges to both product availability and feasibility for the 2025 time period. Minnesota Power anticipates that with the passing of the Inflation Reduction Act, demand for panels, equipment, and labor will increase significantly in the short-term potentially driving up pricing until more solar manufacturing comes online and available labor increases. The Company's recommendation of 200 MW of additional solar in the 2021

Plan, combined with the additional proposed wind resource, provides a practical more diversified approach to adding solar for this resource plan.

e. Comments Regarding Whitewater Kayaking Opportunities and the Thomson Dam

Minnesota Power appreciates the concerns brought forth by the multiple parties with regard to the flow of water at the Thomson Dam and always strives to work with interested stakeholders as the Company is a long-time supporter of recreational groups throughout its service territory. Minnesota Power is the largest hydro operator in the State of Minnesota and all of its reservoirs and flow rates are strictly regulated by the FERC and must meet the license requirements set forth.

The current FERC license for the St. Louis River Project, which includes Thomson Dam, expires at the end of 2035; that process will begin its renewal in 2029. The FERC licensing process is the appropriate place for stakeholders to bring forth their feedback and input regarding the operating parameters of the Thomson Dam. While the Commission and this IRP docket are not the appropriate venues to bring these concerns, the Company has worked closely with both whitewater kayakers and the Minnesota Department of Natural Resources ("DNR") in good faith on licensing requirements and recreational plans. However, recreational desires must be balanced with the interests of all customers in terms of wildlife, river ecosystems, energy supply and cost impacts to customers. Hydro is a renewable resource and an important part of both Minnesota Power's current energy supply and in achieving its vision for 100 percent carbon-free energy by 2050. Any changes to flows would result in lost generation to customers, which needs to be thoroughly considered through the appropriate FERC licensing process.

f. Health Equity Report, Boswell and Hibbard

Minnesota Power has reviewed the April 2022 report titled Incorporating Health and Equity Metrics into the Minnesota Power 2021 Integrated Resource Plan, prepared by PSE Healthy Energy on Behalf of Fresh Energy, Minnesota Center for Environmental

Advocacy, and the Sierra Club ("Health Equity Report"). While the Company appreciates the CEOs work to consider equity in its recommendations in this IRP proceeding, Minnesota Power has serious concerns about the data, inputs and modeling utilized in this report. Through this section, the Company identifies numerous factual inaccuracies and mischaracterizations of its operating units that were used to support recommendations in the Health Equity Report.

In regards to the modeling utilized in the Health Equity Report, Minnesota Power notes that utilities typically do not conduct their own independent health impacts modeling as part of resource planning. This type of modeling is the responsibility of expert and disciplined state and federal environmental regulators who utilize such models to establish appropriate regulations and set permit/operational conditions that are protective of human health and the environment. As such, Minnesota Power cannot comment on the specifics of the modeling platforms used or the various output results presented in this Health Equity Report.

However, Minnesota Power has reviewed the methodology notes and the modeling inputs along with other statements made throughout the Health Equity Report. Overall, the Health Equity Report represents a misleading and inaccurate assessment of numerous important aspects of the Company's operations, which undoubtedly negatively impact and skew any health modeling reports or conclusions. Minnesota Power hereby notes the following factual inaccuracies and/or insufficient contextualization contained in the Health Equity Report. This review should not be construed as a comprehensive analysis of all the claims made or implicit Company approval of items that are not mentioned here by name.

Narrative Descriptions

- Hibbard Renewable Energy Center is not "attached" to the paper mill as the Health Equity Report describes (Page 1, 27, 28). While it is geographically *adjacent* to the paper mill site, it is not attached in any integral way beyond a steam supply pipe extending to the mill, which is not currently in use. The two facilities are under different ownership, operation, and control, with separate environmental permits.

- Hibbard is repeatedly described in the Health Equity Report as burning “paper waste” or “paper pulp” (Page 5, 27, 28). Hibbard does not combust these materials. When the adjacent paper mill was in operation, Hibbard burned limited quantities of *mill bark*, which is different from paper waste or paper pulp. Mill bark is removed from local biomass supply used to make paper; it is not a waste or pulp created as a byproduct from/after/during the papermaking process.

Section 3.2.5 Coal Plant Ash Disposal

There are numerous misleading statements in the Health Equity Report regarding “coal plant ash”, which is commonly referred to as “Coal Combustion Residuals” or “CCR” by industry experts and the U.S. Environmental Protection Agency (“EPA”).

First, the following sentence was included in the Health Equity Report:

> “*A 2021 inspection rated the Unit 3, Unit 4, and Bottom Ash Surface Impoundment at Boswell as a significant hazard to the environment and nearby infrastructure in case of failure”.*

This statement lacks important context. The EPA’s ranking system for impoundment hazards is adopted from the Federal Guidelines for Dam Safety, Hazard Potential Classification System for Dams[23]. Boswell’s impoundments are ranked as a Significant Hazard due to the size and volume of the materials in the impoundments, not because of structural integrity or stability concerns.

In fact, the same 2021 inspection report cited in the Footnote 61 of the Health Equity Report (but not included or even mentioned in the Health Equity Report narrative) states the following:

> *Through review of historic data, review of embankment geometry and geotechnical data, and geotechnical evaluation of stability, the surface impoundments at BEC* ***meet the requirements for structural integrity criteria for existing CCR***

[23] https://archive.epa.gov/epawaste/nonhaz/industrial/special/fossil/web/pdf/fema-333.pdf

> ***surface impoundments and satisfy 40 CFR Subpart D §257.73.*** *Periodic assessments will continue to be conducted in accordance with the timeframes outlined in §257.73 [emphasis added]*

Furthermore, Boswell's impoundments are inspected by qualified professional engineers on a regular basis in accordance with the Federal Coal Combustion Residuals Rule, and all inspection reports are publicly available on Minnesota Power's CCR Website.[24]

Mischaracterization of Boswell groundwater results is also abundantly present in the Health Equity Report. For example, the report references 2016 and 2017 groundwater monitoring data obtained from the Ashtracker website (footnote 62, Page 25), stating:

> *"Of Boswell's 17 monitoring wells, 10 recorded exceedances of federal pollutant standards during this period"*.

Again, the Health Equity Report authors fail to provide critical context surrounding the "10 recorded exceedances", a statement which attempts to conflate EPA's drinking water advisories (designed to protect drinking water supplies) as being applicable to the CCR groundwater monitoring wells which are immediately adjacent to the Boswell impoundments. Drinking water wells are not located within the aquifer that is being measured at the Boswell impoundments monitoring wells, and therefore those EPA advisories are not applicable. Boswell has remained in compliance with CCR groundwater requirements.

Similarly, the Health Equity Report selectively highlights certain groundwater parameters as being above regulatory standards, yet somehow fails to acknowledge those compounds are naturally occurring and occur upgradient of the impoundments, a "natural background" condition which is accounted for in EPA regulations and is a fairly common occurrence. Again, this information and all groundwater reports are publicly available on Minnesota Power's Coal Combustion Residuals (CCR) website[25].

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[24] https://www.mnpower.com/Company/CoalCombustionResiduals
[25] https://mp-ccr.azurewebsites.net/Content/Facilities/Boswell/Groundwater_Monitoring/BEC%202021%20Annual%20Groundwater%20Monitoring%20and%20Corrective%20Action%20Report%20-%20All%20CCR%20Units.pdf

In regards to Boswell's compliance history, additional misleading information continues to dominate the Health Equity Report narrative. On Page 25, the Health Equity Report states the following:

> "Boswell has had five inspections over the past five years according to the EPA's Toxic Release Inventory. During that time, it spent four quarters (a total of 12 months) in noncompliance with the Clean Water Act, including one for significant violations".

To again provide context regarding this claim, the non-compliance events cited represent isolated incidents throughout five years of operations, not continued non-compliance throughout an entire quarter or a full 12 months. Additionally, the "significant violation" noted was due to a late monthly report submittal, not a water quality violation.

Characterizing air pollutant emissions

Minnesota Power reviewed the emission factor methodology outlined in Health Equity Report Section 2.2 as well the outputs presented in Tables 1, 2, and 6. Based on that review, significant numerical differences in several input parameters were found; however, the data selection process used by the Health Equity Report authors was inconsistent.

In some cases, the Health Equity Report authors choose to use actual data which Minnesota Power reported to the federal and state governments (i.e. the EPA and MPCA). Setting aside the appropriateness of a third-party non-regulator using that data in epidemiological modeling, Minnesota Power agrees with the accuracy and appropriateness of those data points; for example, NOx, SO_2, CO_2 values at Boswell 3 and 4. For these specific parameters at these units, the Health Equity Report Table 1 data matches what the Company reported to the EPA and MPCA.

In several other cases, however, the Health Equity Report authors then switch approaches and elect to use an entirely different dataset, abandoning the actual facility emissions data, which they used for other components of the modeling and which are readily available and certified by state and federal regulatory agencies. Instead, the authors elect to use emission factors for certain modeling inputs, which are generally both the highest values they could use, and also the least representative data for actual facility emissions.

This is an irresponsible approach for data analysis and modeling, as there is a well-established hierarchy for responsible data source selection. For both regulators and regulated entities like Minnesota Power, ensuring the highest quality data available used is paramount. When the Company conducts important modeling or other important risk assessment activities, the most comprehensive and accurate available data is always used, not the data that meets its desired modeling outcomes.

Data collected from continuous monitoring systems is selected first when possible, as it is the most comprehensive and accurate data available. The next dataset in this hierarchy is onsite emissions test data, which is not as comprehensive as continuous emission data but is still highly accurate. The last and least reliable dataset are general, non-specific industry or sector emission factors, used only when other data are unavailable. Yet the Health Equity Report authors selected exactly this data – the highest numerical values and the lowest relevancy -- in lieu of the actual data they used for other analyses. This is not due to lack of data availability; testing data was available in places for non-continuous monitored parameters such as volatile organic compounds ("VOC"s) or filterable particulate matter less than 2.5 microns ($PM_{2.5}$).

The Health Equity Report authors' choice to use canned (and elevated) industry emission factors recklessly inflated the $PM_{2.5}$ model results, upon which much of the Health Equity Report's findings are based. This data choice grossly over-exaggerated -- by orders of magnitude in some cases -- the emissions actually generated by units during the selected reporting years. Predictably, using this $PM_{2.5}$ data as a model input by the Health Equity Report authors resulted in inaccurate and inflated model outputs, which subsequently led to unjustified conclusions.

Excerpts from Health Equity Report Tables 1 and 6 Compared to Reported Data:

Table 1 – Boswell 3 **2018 – 2020 average annual emissions**	**$PM_{2.5}$** **Metric tons**
Health Equity Report Data	58.6
MP Actual Reported Data (to MPCA)	1.6

(note, the above also impacts the $PM_{2.5}$ and VOCs lbs/mwh sections of Table 2)

Table 1 – Boswell 4 **2018 – 2020 average annual emissions**	**$PM_{2.5}$** **Metric tons**
Health Equity Report Data	170.4
MP Actual Reported Data (to MPCA)	25.9

(note, the above also impacts the $PM_{2.5}$ and VOCs lbs/mwh sections of Table 2)

Table 6 – Hibbard **2018 – 2020 average annual emissions**	**NOx** **Metric tons**	**SO_2** **Metric tons**	**$PM_{2.5}$** **Metric tons**
Health Equity Report Data	401	101	28
MP Actual Reported Data (to MPCA)	355	85	9

As stated in the beginning of this section, while the Company appreciates the CEO's attempt to consider equity in its IRP analysis, Minnesota Power has serious objections to and concerns with the data selection approach used by the Health Equity Report authors, practices which subsequently inflated and skewed the model results. Important and readily available contextual information was omitted from the report, seemingly in an attempt to depict an alarming and ultimately mischaracterized picture of Minnesota Power's environmental performance and operations.

g. Response to OAG's Assessment of Forecasting Accuracy

The OAG's assessment of Minnesota Power's past forecasting accuracy is faulty and misleading. The Company has an extensive history of fairly accurate forecasting, despite more than half of its load being comprised of large industrial facilities that often idle temporarily due to global market conditions or simply shut whole machines down permanently.

The OAG chose to examine the 2009-2019 Annual Forecast Reports (or "AFRs"), during which the annual system energy requirements were over-forecasted by 8 percent on average. However, a considerable portion of the error incurred in this timeframe is attributable to three distinct issues:

1) AFR's 2013 and 2014 assuming Essar Steel began mining operations in 2015,
2) The significant iron and steel industry downturn in 2015-2016, and
3) The 2020 Recession that resulted from the COVID19 Pandemic.

If these observations are removed from consideration, the annual system energy requirements were over-forecast by just 2.8 percent on average.

The OAG asserts that Minnesota Power has a pattern of over forecasting, and developed highly-tailored and odd statistics as evidence of this "pattern," for example:

> "The Company's forecast overestimates are also remarkably consistent: every AFR from 2009 through 2014 has overestimated load—for both energy and peak demand—in every year from forecast-years 7 through 12. In other words, there is not a single observation (out of a possible 42) in which load was underestimated in forecast-years 7 through 12 over this period."

The apparent "remarkably consistent" overestimation result from the OAG's approach to error analysis, which in this case is based on 21 observations that the OAG appears to count twice. Further, there is only one observation for year 12 (AFR 2009), two observations of errors in year 11 (AFR 2009 and AFR 2010), … So the "overestimation" in the long forecast horizons are not consistent among all of Minnesota Power's forecasts;

these errors are not indicative of all AFR’s or even all AFR’s examined in the highly-tailored statistic cited by the OAG (AFR’s 2009-2014).

The OAG’s assertion of systematic bias is without merit. The Company’s load forecasts are accurate and more than acceptable for planning purposes.

V. MINNESOTA POWER'S PERSPECTIVE ON INTERVENOR MODELING ANALYSIS

Minnesota Power is appreciative of the additional modeling work placed into the record by the Department and CEOs in this IRP proceeding. As stated earlier, Minnesota Power commenced a first-of-its-kind stakeholder engagement process prior to developing this IRP. Specific to modeling, four virtual meetings held with stakeholders where the Company presented modeling assumptions and solicited stakeholder feedback. At the end of the process, Minnesota Power believes that participants seemed generally satisfied with the final set of assumptions used in the IRP analysis. This set a solid modeling foundation for stakeholders to start their review and focus on the issues in this IRP, and not debate the assumptions since those conversations occurred earlier in the process. It is a testament to the stakeholder engagement process and Modeling Subcommittee's work prior to filing this IRP that adjustments made to Minnesota Power's modeling were minor compared to prior IRPs or other regulatory proceedings.

After Minnesota Power filed its IRP, the associated EnCompass models were made available upon request. It is typical for stakeholders to review the models for errors, methodology, and update any assumptions that might have changed since the IRP filing. Minnesota Power would categorize the majority of the updates made by either the Department or CEOs as updates to assumptions because better information was available. For example, stakeholders adjusted the Company's ownership share of NTEC with the announced sale to Basin Electric and updated renewable cost outlooks to more recent forecasts. In the Department's supplemental modeling, they ran scenarios that took into consideration a new transmission project within the Company's service territory that was proposed in MISO's Long Range Transmission Planning Tranche 1.

The remaining changes were made to the modeling approach or methodology, which will be discussed further below. With 18 months between when Minnesota Power filed the IRP and when reply comments were filed there inevitably will be better information available over such a long period of time. However, it is important to consider whether these changes are material to the overall IRP proceeding. When an IRP process is significantly delayed it introduces the risk of material changes occurring that may delay the execution of short term action items proposed and delay the timing of the next IRP where those changes can be incorporated into the analysis.

Minnesota Power believes the initial modeling put on the record by the Company is still representative for planning purposes and strongly supports the proposed 2021 Plan. The pricing forecast updated by the CEO for new wind, solar, and energy storage are within the range of sensitivities that Minnesota Power studied, and the Company identified that its 2021 Plan remained robust even under these potential outcomes. With the well-publicized supply chain issues caused by transportation issues, labor shortages, and critical materials being unavailable, cost for renewables and storage are likely higher than what was modeled, especially in the near term. However, the historic Inflation Reduction Act ("IRA") of 2022 is anticipated to improve the economics for renewables and other technologies like energy storage and nuclear. Given IRP's have become multi-year proceedings, assumptions and better information will become available over the course of the proceeding. It is the Company's position these changes do not alter the direction of its Preferred Plan in this IRP and stress the strategic plan to identify key differences invoked with these outcomes.

In September 2021, Minnesota Power announced a portion of its supply from NTEC would be reduced due to North Dakota-based Basin Electric becoming a 30 percent owner in the facility; Minnesota Power will retain a 20 percent energy and capacity off take from NTEC. Both the Department and CEOs provided analysis in this IRP with the reduced off take from NTEC. Minnesota Power did not submit new analysis with the reduced ownership share because the change was not material to Minnesota Power's overall plan. Additionally, NTEC has numerous regulatory and legal processes yet to complete. With the NTEC ownership reduction, Minnesota Power is expected to have sufficient energy and capacity through 2029 until the proposed Boswell Unit 3 transition off coal. Setting aside the Department's "FastExit" recommendation that would require capacity replacement resources in 2025, Minnesota Power is currently expecting a modest capacity need beginning in 2030 of about 150 MW and some energy replacement for periods when wind and solar renewable energy is unavailable. Given this is not a large need, Minnesota Power will have time to address this need in the next IRP proceeding and propose a solution.

The additional time prior to the Company's next IRP will give energy storage technologies and other carbon free technologies an opportunity to mature and costs to evolve with more information known about their capabilities to replace dispatchable generation that has a firm fuel supply on-site. The Company can also incorporate IRA impacts, and ongoing reliability discussions and work occurring at MISO and various stakeholder and resource planning forums. If Minnesota Power were to adapt conclusions from the Department's or Minnesota Power's modeling of various Boswell retirement scenarios in this IRP, the least cost technologies to replace Boswell that have similar operating attributes are peaking or intermediate natural gas facilities. Minnesota Power recognizes that the reduction in NTEC ownership is a change in the power supply, but when looking at the broader power supply portfolio, it does not materially impact Minnesota Power's proposed plans for Boswell Energy Center's transition off coal and does not create an immediate energy or capacity need to be addressed in this IRP.

Minnesota Power requested from the Department and CEOs copies of their EnCompass model input and output files that were used to support their recommendations. The Company also requested from the CEO assumptions and associated workbooks used to update their renewable pricing and to develop a Purchased Power Agreement ("PPA") cost structure for renewables. The following section discusses Minnesota Power's analysis and findings from reviewing this requested information.

a. Minnesota Power's Response to the Department's Modeling

In the Department's Initial Comments filed on February 1, 2022 the Department recommended approval of the Company's IRP with modifications. A key similarity between the Department's initial recommendation and Minnesota Power's 2021 Plan is the continued transition away from coal generation, although there is disagreement about the pace of the transition. The Department's recommended modifications were to modify the retirement dates for Boswell Units 3 and 4 in the "FastExit" scenario.

Compared to Minnesota Power's Preferred Plan, the Department recommended accelerating Boswell Unit 3 retirement from 2029 to 2025 and accelerate Boswell Unit 4 retirement to 2030. Minnesota Power's Preferred Plan recommended ceasing coal operations at Boswell Unit 4 in 2035.

Although their modeling was selecting more than 900 MW of replacement gas generation, the Department did not specifically recommend a dispatchable replacement for Boswell Units 3 and 4. In general, renewable additions were similar between the plans where the Department recommended 300 MW of wind in the mid-2020s, and Minnesota Power recommended 200 MW of wind in the same time period. Since Initial Comments, the Department modified their recommendations in Supplemental Comments filed July 29, 2022. The Department will provide its final recommendations in Reply Comments.

Initial Comment Modeling

In reviewing the Department's modeling the Company noticed that the majority of the plans evaluated showed "FastExit" as the least cost scenario. The Department stated in their filing that "The Company's FastExit scenario was the least cost plan in 754 of the 768 contingency/cost future combinations." As a reminder, the "FastExit" scenario includes Boswell Unit 3 retiring in 2025 and Boswell Unit 4 retiring in 2030.[26] This was a drastic change from the conclusions in Minnesota Power's IRP modeling, where the Company showed multiple Boswell Unit 3 and 4 retirement scenarios being least cost depending on the carbon/environmental cost assumptions and sensitivity (i.e. high and low gas price sensitivity). For example, in the Reference Case Scenario, the Company's 2021 Plan was least cost in 27 of the 38 model runs. In that same future, the "FastExit" scenario was selected 3 of the 38 model runs. When Minnesota Power started to review the Department's Encompass models the Company focused on the assumptions in their "FastExit" scenario.

Minnesota Power's first step in reviewing the Department's Encompass model was verifying that the Company could receive similar results as the Department demonstrated

[26] Note that in MP's original IRP filing the Company refers to the "FastExit" scenario as the "Expedited Retirement of BEC 3 and 4".

in their Reply Comments. Minnesota Power selected several cases to re-run using the input files provided by the Department. The results were compared to the results shown in the Department's Reply Comments. Minnesota Power confirmed the results were the same. Minnesota Power now knew they were reviewing the same models the Department had used in their analysis.

Minnesota Power first started to review the Department's "FastExit" scenario given that scenario was least cost in nearly all their model runs. Minnesota Power observed in their analysis that the "FastExit" scenario was several hundred million dollars lower cost than Minnesota Power's Preferred Plan. The Company did not observe this in their analysis and concluded the "FastExit" case must be missing some cost input. To make their data and results easier to review, given models typically involves thousands of inputs and multiple rows of output to parse through, the Company used their own tools to evaluate the Department's results. In that process the Company identified that the "FastExit" plan was missing the capital cost for new combined cycle and combustion turbine gas resources. The Department's expansion plans for the "FastExit" scenario was selecting between 900 MW to 1500 MW of replacement gas generation at zero capital cost. Excluding the capital for that volume of new gas generation would have a material impact on the total cost for that plan.

Note that in the Department's other Boswell retirement scenarios the capital cost for the gas generation was included in the analysis. This error only impact their modeling runs for the "FastExit" scenario.

To get a sense for the impact this error had on the total cost of the "FastExit" plan, Minnesota Power added back in the capital cost for the replacement gas generation. For a few select cases Minnesota Power reran the models with the error fixed and observed changes in the least cost plan rankings. For example, in the Reference Case Scenario as modeled in the Department's EnCompass model, the least cost plan shifts from "FastExit" to the "PrefPlan". Minnesota Power referred to the "PrefPlan" as the "2021 Plan" in Company's filing.

On June 1, 2022 the Company met with the Department analysts that worked on the EnCompass modeling to discuss the error discovered. Minnesota Power recognizes that this is a new model being used in Minnesota for resource planning and all parties are using it for the first full IRP in this proceeding. At the time of this discussion the Department communicated they would like to fix the error and resubmit modeling results.

Supplemental Comment Modeling

The Department filed supplemental comments on July 29, 2022 that included updated EnCompass modeling which addressed the error in capital cost for replacement gas generation. In the Department's supplemental comments, their prior recommendation transitioned to a conclusion based on modeling results. Their conclusion was that the modeling results continued to suggest the "FastExit" retirement scenario and replacement of Boswell with nearly 900 MW of new gas generation, with the first gas unit being in service by 2026 – just over three years from now.

Minnesota Power followed a similar process as it did for Initial Comments, where the Company requested the Department's EnCompass files and reviewed them for accuracy and reasonableness. The Company verified that the capital cost for new gas generation is now being accounted for correctly. The "FastExit" scenario is no longer least cost across the majority of the scenarios ran by Department. Given the close proximity of plan costs across the Boswell retirement scenarios, the least cost retirement scenario will vary depending on the scenario and sensitivity. Minnesota Power did not identify any other areas of concerns when reviewing the updated EnCompass models.

In review of the Department's analysis, Minnesota Power struggled to follow the logic the Department used to develop their conclusion. The Department ran 3,840 expansion plans that varied NTEC ownership, customer demand, carbon regulation cost and environmental cost, and transmission upgrade costs to facilitate a Boswell retirement. It was unclear under what scenario or scenarios the conclusions were being drawn from. Furthermore, their conclusions did not factor in the several delays and the impact those would have implementing their "FastExit" plan. For example, it is not feasible for Minnesota Power to retire Boswell Unit 3 and develop, permit, procure, and construct a replacement combustion turbine by 2026 (as discussed earlier in these Reply Comments). Please refer to Minnesota Power's earlier discussion on the concerns and reality of successfully accomplishing a "FastExit" of Boswell.

Minnesota Power was encouraged to see that the Department's final recommendation will be stated in reply comments. The Company strongly agrees with the Department that a well thought out transition away from coal should consider the following, as described by the Department in supplemental comments of page 54:

> *"The Department must also consider important policy considerations that help balance our statutory mandates to achieve low rates, promote renewable energy, protect consumers from excessive risk, and balance these concerns against broader socioeconomic considerations, including impacts to workers and host communities"*

Minnesota Power also agrees with the Department that modeling, such as with EnCompass model, is one useful tool and an important part of the resource planning process. However, both the Department and the Company recognize that the EnCompass tool has limitations and the reasonableness of executing a plan along with the socioeconomic and host community impacts need to be factored into a recommendation, such as the development timeframe of new transmission resources and new gas resources. The Company looks forward to reviewing the Departments final recommendation in Reply Comments.

b. Minnesota Power's Response to the CEO's Modeling

The CEO's recommendation in their comments also concluded that moving away from coal generation is in customers' interest. The timing of the Boswell Unit 3 transition aligned with Minnesota Power's 2021 Plan, with Boswell Unit 3 retiring by 2030. There was general agreement that continuing to operate Boswell Unit 4 was in the interest of customers as the Company works through its coal free transition plan. Minnesota Power agrees that planning for transmission system reliability requirements to facilitate a Boswell Unit 4 retirement is needed, and those activities have already begun with the Company's proposed Northland Reliability Project being included in the MISO LRTP that was approved by the MISO board in July 2022. However, this specific transmission solution addresses system reliability (i.e. moving energy from generation to customer), but it does not address the source, attributes, and type of generation that could replace retired Boswell generation. In the Company's next IRP, a key focus will be the energy attributes needed for replacement energy and bringing forward a plan that aligns with the Company's carbon reduction goals while serving customers reliably.

Minnesota Power does have concerns with some of the recommendations by the CEOs, including the retirement of the Hibbard facility in 2023, withdrawal of NTEC, and replacing those dispatchable resources with 600 MW of intermittent solar. Minnesota Power is concerned that the CEO's recommendation to remove effectively 175 MW of dispatchable generation (assumes Minnesota Power's 20 percent ownership of NTEC) with 600 MW of solar is not a reliable or energy adequate replacement. Within MISO there is a general concern that continuing to retire or forgo investment in dispatchable or controllable generation will result in a unreliable power supply where energy interruptions are more frequent, which on Minnesota Power's system can occur when temperatures are below negative 20 degrees Fahrenheit. If Minnesota Power were to experience a Winter Storm Uri type event as Electric Reliability Council of Texas ("ERCOT") and SPP did during sub-zero temps, the impact to lives, homes, and businesses could be extensive.

As discussed earlier, Minnesota Power believes that more detailed analysis and collaboration with stakeholders and regulators is needed to establish best planning practices (i.e. reliability metrics) to help ensure reliability all year and through weather events. That way Minnesota customers can receive the same level of energy service as they did before the transition to carbon free resources. The use of traditional planning practices and models has served Minnesota well as Minnesota Power and others utilities transitioned their generation resources over the past 15 years. However, current tools and practices will not be adequate for the next phase towards a carbon free future. The CEO's recommendation did not take into consideration the attributes being removed with the Hibbard and NTEC removal, and did not adequately address how those would be replaced with 600 MW of intermittent solar to serve a utility with one of the highest load factors in the country. The Company also believes the CEO's analysis is incomplete and did not factor in several of the environmental futures, including the Reference case, as required.

Hibbard Energy Center

Minnesota Power does not believe it is reasonable to retire Hibbard without a retirement study completed and the impact to both the system and the host community (Duluth) understood. A retirement study has become the standard for evaluating the retirement of thermal resources to help ensure all attributes are replaced adequately, system reliability issues are identified and addressed, customer cost impacts are evaluated, environmental impacts are studied, and the host community impacts are considered. Hibbard is a carbon free dispatchable resource that uses mostly locally sourced biomass to generate energy. As these comments are being prepared, Hibbard is currently being dispatched by MISO to address local reliability issues with significant run rates to support the region and grid during this time. This demonstrates that transmission system upgrades or replacement resources with similar generation attributes might be needed to facilitate a Hibbard retirement.

Minnesota Power's mission for Hibbard was to operate as a peaking resource, but with the higher energy prices and competitively procured biomass, Hibbard has been operating more than expected. In 2021, Hibbard Units 3 and 4 operated at a 20 percent and 23 percent capacity factor, respectively. Hibbard is a valuable carbon-free dispatchable resource for customers and the CEO's recommendation to retire Hibbard in 2023 is not supported by any analysis or factors in the current state of MISO with capacity shortfall and concerns about being able to serve energy needs reliably.

Feasibility of Additional Wind and Solar

Minnesota Power also has concerns with the feasibility and impacts of adding 600 MW of solar by 2026 to the power supply. The main concerns are the curtailment risk identified with the CEO's recommended plan in addition to the reliability concerns of this much solar in Minnesota Power's power supply replacing dispatchable generation. With 600 MW of new solar the modeling demonstrates the potential for wind curtailment on the system to more than double and solar curtailment to increase from ~5 GWh a year to ~150 GWh a year. The 200 MW of solar proposed in the Preferred Plan is more manageable from a system perspective and a better option for customers from a cost perspective as it minimizes reduces curtailment risk, and provides better alignment with customer needs.

Another concern is the feasibility of cost effectively adding 600 MW of solar by 2026. Although not as significant of a concern as curtailment and reliability mentioned above, 600 MW is a significant amount of solar to add in the next 3 to 4 years for a 1700 MW system given current market conditions and delays in the MISO interconnection que. Minnesota Power recognizes that the passing of the IRA could alleviate some of the cost concerns and increase availability of solar equipment, but the supply and timing issue is multifaceted. There are several factors that can impact solar development that need to be considered, including availability of critical materials, manufacturing capabilities, international trade policy, tariffs and import restrictions.

While the Company acknowledges more solar energy additions are in the public interest, and has proposed 200 MW of new solar additions in its Preferred Plan, the Commission must consider the need for even more solar energy, the reliability impacts and the realities of supply chain challenges of acquiring more solar than currently needed. Minnesota Power believes adding 600 MW of solar by 2026 is too large for the Company's power supply in this planning period, which is already well on its way to be 70 percent renewable by 2030 if the Company's Preferred Plan is approved by the Commission.

The CEO's Preferred Plan also included 100 MW of wind by 2030, which is relatively close to the Company's recommendation to add 200 MW of wind by the mid-2020s. There is agreement that additional wind prior to 2030 is in the customer's interest.

Modeling Evaluation

The CEOs only evaluated capacity expansion plans in the High CO_2 regulatory cost and high Environmental Cost. As directed in the Order establishing 2020 and 2021 Estimate of Future Carbon Dioxide Regulation Costs (Dockets Nos. E999/CI-07-1199 and E999/DI-

19-406) there are varying level of carbon regulation cost and environmental cost that need to be evaluated in an IRP proceeding. As stated earlier, Minnesota Power believes the CEO's analysis is incomplete as it did not factor in several of the environmental futures, including the Reference case.

Post 2030, the CEO's Preferred Plan included a mix of additional wind, solar, storage, and battery hybrid to replace Boswell Unit 3. Notably, there was no gas generation selected as in the Department's modeling. It is unknown in the CEO's modeling if the attributes of dispatchable gas generation would have been a better fit. Minnesota Power believes there is time in the next IRP to more thoroughly evaluate and bring forward replacement options for Boswell Units 3 and 4 and no action is needed in this proceeding to identify replacement options for post 2030.

In the IRP analysis Minnesota Power modeled two levels of higher energy efficiency savings as resource alternatives, "High" and "Very High". Those energy efficiency scenarios, along with the base energy efficiency scenario, were based on the 2020-2029 Minnesota State Demand Side Management Potential Study ("MPS"). In the CEO's EnCompass modeling they forced in the "High" energy efficiency scenario in their base case. They did not let the model economically select the higher energy efficiency levels is the capacity expansion analysis. The modeling by Minnesota Power and the Department did not show increasing levels of energy efficiency as economical for customers. Minnesota Power is already a leader in conservation programs and electrification efforts. The Company has surpassed the State's conservation goals for the last decade and identified ambitions energy savings goals in it 2021 – 2023 CIP triennial that align with the "base" energy efficiency modeled in the IRP and direction given in the prior IRP. In the 2021 program year, the Company achieved energy savings of 2.8 percent of gross annual retail energy sales, well about the state goal of 1.50 percent and the 2.5% savings goal set in the 2015 IRP. Although the CEOs modeled the "High" energy efficiency scenario in the base case, they didn't go as far as recommending an increase. Minnesota Power agrees with the CEOs, which increasing the Company's state leading energy efficiency program is neither supported by the IRP modeling nor needed at this time.

Minnesota Power followed the same process reviewing the CEOs EnCompass modeling and assumptions as it did with the Department's modeling. Minnesota Power began with the review of the changes made to solar, wind and battery storage costs. In general, the Company agrees that use of latest information for renewable cost is good practice and did not have concerns with the use of the latest National Renewable Energy Laboratory ("NREL") Annual Technology Baseline and Energy Information Administration Annual Energy Outlook ("EIA AEO") data from 2021 for solar and wind, and storage. However, Minnesota Power has seen increase in solar and storage cost since the since the 2021 NREL and EIA AEO releases used by CEO. As an example, Minnesota Power compared the solar and energy storage cost outlook purchased from a third party (IHS Markit). Between the 2021 and 2022 reports for a 2026 in-service project cost for solar increased by 22 percent and li-ion 4 hour storage increased by 37 percent. With increasing demand and stresses and bottlenecks emerging at various points of the material and manufacturing supply chain for renewables and storage there is uncertainty on what actual procurement cost will be. With that said, Minnesota Power believes the renewable cost modeled by the CEO were within the ranges of cost modeled by the Company.

Minnesota Power appreciates the CEO's identifying that the EnCompass model is not dispatching the resource alternative "Demand Response Product B" correctly. The EnCompass model was not respecting all the operational parameters for the proposed demand response program. Minnesota Power plans to investigate this issue further and work with EnCompass on a solution. Minnesota Power agrees with the CEOs, that demand response would add value to the Company's power supply and it's important to get the model to capture that value correctly. This finding does not have a significant impact on the finding in this IRP given new demand response programs are not being recommended in the short-term action plan.

c. Minnesota Power's Conclusions on the Department's and CEO's Modeling

Minnesota Power is appreciative of the robust analysis that stakeholders put into the record in this IRP. The limited changes to the modeling, and general consensus on core attributes of the plans, is a testament to the robustness of the stakeholder process initiated before the Company filed its 2021 Plan. The modeling generally demonstrated that moving away from coal would be in customer interests by reducing carbon emissions and other pollutants, and augmenting the power supply with additional wind and solar by 2030. However, the timing of retirements and the level of renewables varied across the stakeholder modeling.

It is Minnesota Power's opinion that not all recommendations were based on the robust analysis required by statute. For example, the CEOs only evaluated capacity expansion plans in the High CO_2 regulatory cost and high Environmental Cost. Per planning requirements, there are varying level of carbon regulation cost and environmental cost that need to be evaluated in an IRP proceeding. Also, the OAG perspective on NTEC appears to be based on a spread sheet exercise, not nearly the level of work that supported the record in the NTEC regulatory proceeding where Minnesota Power received approval. The Commission should take into consideration the level of analysis and if it meets the best practices established through the states robust planning process when reviewing a stakeholder's recommendation.

Minnesota Power continues to believe the Preferred Plan is holistically in the best interest of customers. It strikes the balance of reducing carbon, creating a sustainable path to cease coal operations as technology evolves, and provides a reasonable timeline for employees and the host community to plan, while managing a gradual increase in cost during the transition. Figure 3 below shows the change in power supply cost of the Company's Preferred Plan compared to the Department's modeling conclusions and the CEO's recommended plan. This figure is useful in informing where customer rates could go directionally if the actions in each plan are taken. It is important to note, however, that actual rates are decided by the Commission through a rate case proceeding, and those outcomes will be reflected on the customer bill. This simple comparison demonstrates that the Company's Preferred Plan has the most gradual increase when compared to the stakeholder recommended plans.

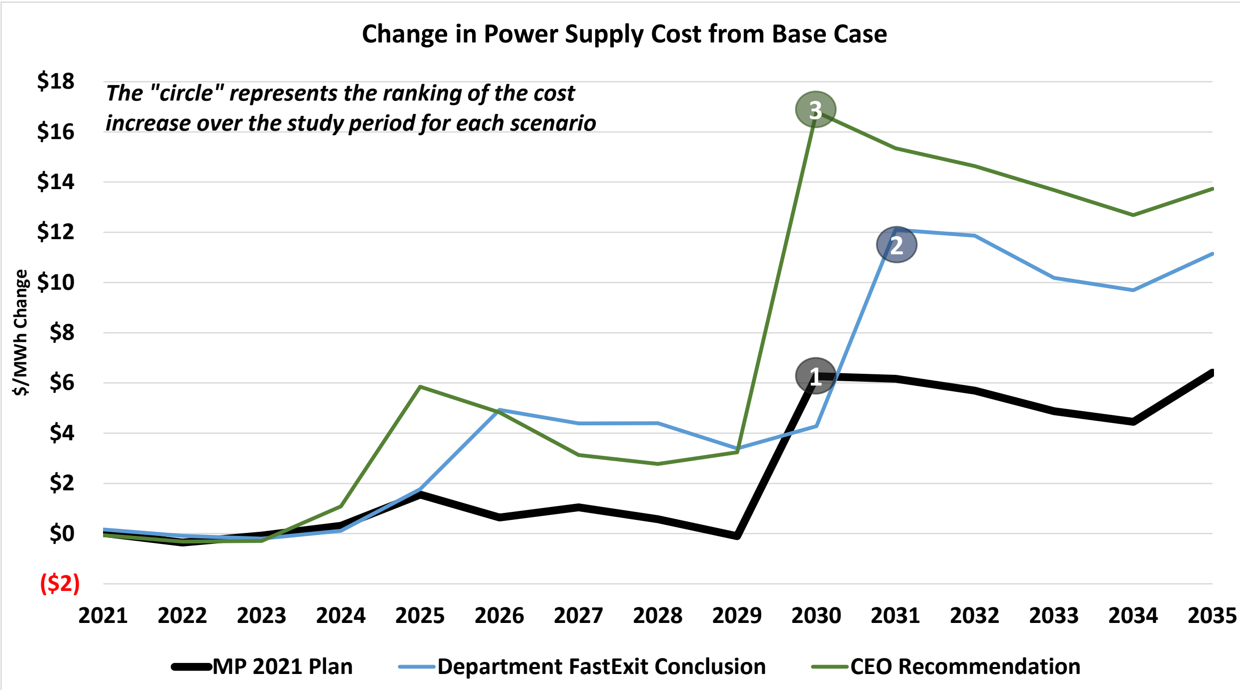

Figure 3: 2021 Plan Power Supply Cost Compared to Stakeholder Recommended Plans[27]

[27] The 2021 Plan and stakeholder recommendations shown in Figure 3 assumes Minnesota Power's 20% ownership of NTEC (except in the CEO's recommendation where NTEC was removed) and Company's cost outlook for renewables and storage used in the 2021 IRP analysis. The power supply cost do not include carbon regulation cost or environmental costs.

VI. MINNESOTA POWER'S RESPONSE TO SPECIFIC QUESTIONS FROM INTERVENORS

In Initial Comments, two organizations – the Department and CUB – requested that Minnesota Power address specific questions. The Department recommended Minnesota Power discuss the impact of the LRTP on the costs and contraints regarding Boswell retirement scenarios, explain the economic and reliability consequences of the Company's natural gas transportation contracts and explain what data and information Minnesota Power has submitted and provided to MISO in its winter fuel and generator surveys. CUB requested that the Company address the impact of the Keetac facility on its optimal portfolio and retirement dates for BEC 3 and 4, explain why its analysis determines that retiring BEC 4 as early as feasible is the least-cost option for the sensitivities that include the return of Keetac, and explain why it is not proposing to retire BEC 4 as early as feasible, given that Keetac is online. They also asked that the Company address the risk and potential ramifications of relying on an environmental future that contains a regulatory cost in its IRP when the Company's actual operations do not have such a constraint.

a. Impact of LRTP on Costs and Constraints

The MISO Board of Directors met in open session on July 25, 2022 where the LRTP Tranche 1 project portfolio was approved. Included in the project portfolio is the Northern Reliability Project (LRTP Project #3) – this project is now referred to as the "Northland Reliability Project". On August 1, 2022, Minnesota Power and Great River Energy ("Co-Owners) filed a joint letter under Minn. Stat. § 216B.246 notifying the Commission that the Co-Owners intend to construct, own and maintain the project named the Northland Reliability Project.[28] The EnCompass analysis factored in the cost of reliability transmission upgrades needed to facilitate an early retirement of Boswell Unit 3 and/or unit 4. The cost of transmission upgrades considered in the Boswell Unit 4 retirement scenarios included cost for an illustrative transmission project for a high voltage transmission line from the Iron Range substation to Benton County substation. The

[28] MPUC Docket. No. E015/ET2/CN-22-416.

illustrative transmission project is very similar to LRTP Project 3. This is a material change in the cost incurred by customers to facilitate a retirement given the LRTP projects will be cost-shared across all MISO Load Serving Entities. In the BEC4 retirement scenarios, this reduces the cost of transmission upgrades by approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**. Note that when evaluating retirements at BEC, the EnCompass model had the choice to select transmission upgrades or new dispatchable gas generation located at BEC. This change reduced the cost of those transmission upgrades. From a planning perspective, the addition of the Northland Reliability Project to LRTP, gives the Company optionality when evaluating options for ceasing coal operations at BEC that the Company will bring forward in the next IRP.

b. Minnesota Power's Natural Gas Transportation Contracts

In its Initial Comments, the Department noted that due to the increasing use of natural gas fueled capacity by Minnesota utilities and events during recent winters it further explored Minnesota Power's exposure to risks related to natural gas transportation. The Department stated that Laskin is the Company's only unit primarily fueled by natural gas and in February 2021 experienced an interruption in gas supply due to natural gas transportation to Laskin. The Department then recommended that Minnesota Power explain in Reply Comments the economic and reliability consequences of the Company's natural gas transportation contracts and explain what data and information Minnesota Power has submitted and provided to MISO in its winter fuel and generator surveys. Below is the Company's response to this question, and attached is Reply Comments Appendix A – its 2021 MISO Fuel and Winter Generator Surveys.

Minnesota Power's strategy for natural gas transportation contracts varies depending on station needs and gas transportation options available for each location. BEC primarily utilizes natural gas for startup and its gas transportation contracts have provided natural gas has been available when needed. Hibbard also utilizes natural gas for startup and is supplied by the City of Duluth. Though there are occasional supply limitations due to demand requirements of the City, Hibbard has been able to coordinate with the City in advance of expected supply limitations to help ensure the unit is running and available when MISO dispatches it. Since Laskin is the only station primarily fueled by natural gas, the most detail is provided for its natural gas transportation contracts.

In its Initial Comments, the Department stated, "For the February 11 to February 17 interruption at LEC the maximum possible lost revenue was about $2.9 million." The footnote associated with this statement clarifies, "Calculated as (average day ahead LMP each day at MP.LASKIN2) * (24 hours) * (99.0 MW) for February 11 to February 17." Minnesota Power does not agree with the Department's analysis that the maximum lost revenue was $2.9 million. As stated in the footnote, the Department calculated the $2.9 million value by multiplying 99MW by the market price of $173.46/MWh times the total hours in the 7-day cold weather event. This is not an accurate calculation because the MISO Locational Marginal Prices ("LMPs") were consistently below the cost of the unit and, therefore, the unit would have likely operated at minimum levels of 15 MW (not maximum levels) during the event time period if it was called on by MISO. Based on the natural gas price at the time of the event, the generation costs for Laskin would have been approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**, which is significantly higher than the market price of $173.46/MWh. Also, the MISO tariff has an Energy Offer Soft Cap of $1,000/MWh requiring the Independent Market Monitor's ("IMM") approval to offer units above that price. Based on this provision, there is no indication whether this authorization would have been granted.

Minnesota Power acknowledges that, during the February 2021 event, there was an interruption in gas supply to the Laskin facility due to pipeline constraints. During this extreme event, daily gas prices averaged as high as $188/MMBtu resulting in a unit value **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** in a market that averaged as high as $425/MWh. Had Minnesota Power been able to procure the transportation and gas to the Laskin facility, the units were dispatched by MISO, and the IMM approved the offer price, costs for the generation would have been in excess over $8 Million higher than not running the generation.

Since the Laskin Energy Center was converted to natural gas from coal in 2015, the initial modeling predicted that the units would generate less than 5 percent of the time. Firm transportation on Northern Natural Gas would currently cost between $1.2M and $3.9M annually, depending on how much and for which month's firm transportation was secured. Firm contracts are fixed payments, whether the gas is used or not; meaning, the fixed transportation costs would be incurred by Minnesota Power customers regardless of how often the Laskin facility generated. Therefore, secondary firm transportation was selected as a least cost supply option so customers were not paying for firm transportation that was only being used 5 percent of the time. This strategy balances reliability of the system with the affordability to customers. Based on the amount of time that the Laskin units have been dispatched by MISO, this strategy has been proven successful. Since the conversion from coal to natural gas in 2015, at least one of the Laskin units have been called on for generation a total of 119 days. Out of the 119 days that one or more units were dispatched by MISO, as shown in Table 1 below, Minnesota Power has successfully been able to procure transportation and gas 112 days – equating to a 94 percent success rate. The February 2021 incident was an extreme and unforeseen event, and as discussed earlier, even if Minnesota Power was able to get transportation and gas to Laskin, the gas prices were so high that the units would not have been dispatched by MISO due to economics.

Prior to converting the Laskin Energy Center to natural gas from coal in 2015, Minnesota Power evaluated the transmission reliability impacts associated with the shift to a peaking operation unit. Minnesota Power's approach, to help increase reliability, was to assume the unit is offline and plan the transmission system to operate reliably for any single contingency event. During the February 2021 incident, the Minnesota Power system was operated as planned and the system remained reliable during that time period; therefore, despite Laskin being in a fuel outage, none of the Company's customers were affected.

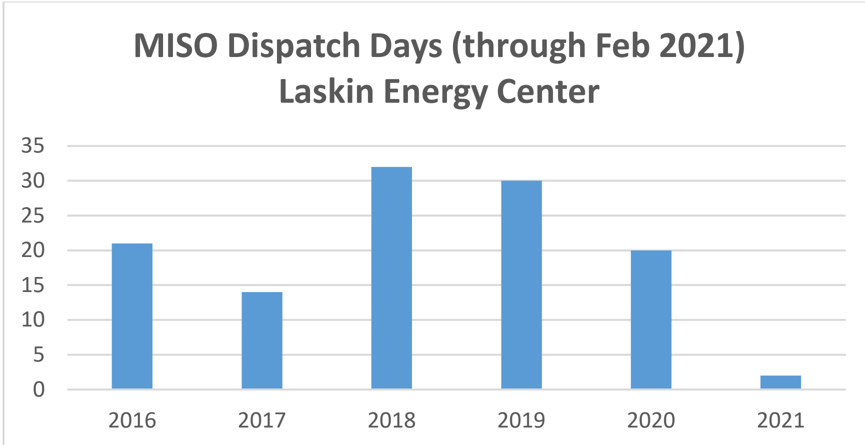

Table 1: MISO Dispatch Days

c. Impacts of the Keetac Facility on Minnesota Power's Demand Sensitivity

CUB requested that the Company discuss why the optimal retirement scenario switches from the 2021 Plan to "Retire BEC4 early as Feasible" under the "AFR 2020 Load w/ Keetac" sensitivity in its Reply Comments. An early observation Minnesota Power had with the Boswell retirement analysis is the net present value of plan cost were very close across the retirement scenarios studied. Even a small change in a single assumption would result in a re-ranking of the least cost plan. Minnesota Power anticipates that is what occurred in the "AFR 2020 Load w/ Keetac" sensitivity case. For this reason, the Company evaluates the aggregate performance of a plan over several sensitivities when developing its Preferred Plan, along with factoring in sustainability, reality of executing a plan, host community impacts, feedback from the stakeholder process, and customer cost impacts. Minnesota Power's Preferred Plan was stressed against multiple sensitivities to help ensure stability across multiple futures, when compared to other retirement scenarios considered. Minnesota Power is not proposing to retire Boswell Unit 4 as early as feasible because when the Company holistically considered the IRP analysis, host community impacts, stakeholder feedback, state and environmental policy goals, and customer cost impacts, transitioning Boswell Unit 3 first by end of 2029 was a better performing plan than retiring Boswell Unit 4 as early as feasible.

d. Environmental Futures and Regulatory Costs

CUB requested that the Company address the risk and potential ramifications of relying on an environmental future that contains a regulatory cost in its IRP when the Company's actual operations do not have such a constraint. Minnesota Power understands the intervenor's concerns around how environmental future and regulatory costs are used in the model. However, the Company follows existing state processes and Commission orders regarding environmental futures and regulatory costs. Minnesota Power does run a case with no carbon regulations in the model and the Company's Preferred Plan was the least cost scenario when no carbon regulations were included.

VII. CONCLUSION

Minnesota Power respectfully requests that the Commission approve the Company's 2021 Plan as presented in its initial February 2021 filing. While the Company's Short Term Action Plan is well underway in the 18 months since initially submitting the IRP, the proposed Long Term Action Plan will result in a power supply that is 70 percent renewable by 2030 and an 80 percent carbon reduction by 2035. In its Plan to cease all coal operations on its system by 2035, Minnesota Power proposes the following actions:

- Retire the Boswell Energy Center Unit 3 by December 31, 2029;
- Add 200 MW of solar that leverages the Boswell site or other Minnesota Power facilities by 2030, leveraging existing interconnections and reinvesting in utility host communities;
- Work collaboratively with customers to pursue up to 50 MW of long-term demand response by 2030 to address future resource adequacy changes;
- Develop and implement transmission solutions to address reliability issues related to the early retirement of Boswell Unit 3; and
- Investigate options to refuel or remission Boswell Unit 4 and associated reliability transmission as coal operations cease by 2035.

The Company's 2021 Plan was informed by a first-of-its-kind, robust stakeholder process and thoughtfully designed to be holistically the best outcome for its customers. Despite many external landscape changes since its initial filing 18 months ago, the Company's Preferred Plan remains the most reasonable. Minnesota Power believes its 2021 Plan will continue to serve its customers in a thoughtful and forward-looking way during the 2021-2035 planning period, and proudly presents a plan that reflects its commitment to its customers, communities, and the climate. The Company appreciates the opportunity to provide these Reply Comments and looks forward to a Commission decision in this docket.

Dated: August 29, 2022

Respectfully,

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STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 7th day of September, 2022, she served Minnesota Power's Corrected Reply Comments in **Docket No. E015/RP-21-33** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

Tiana Heger