Direct Testimony and Schedules
Daniel W. Gunderson

Before the Minnesota Public Utilities Commission

State of Minnesota

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

Docket No. E015/GR-26-199

Exhibit _____

TRANSMISSION

November 2, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Daniel ("Dan") W. Gunderson, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

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

A. I am employed by ALLETE, Inc. ("ALLETE"), doing business as Minnesota Power ("Minnesota Power" or the "Company") as Vice President of Minnesota Power Transmission System Planning and Operations.

Q. Please describe your educational background and work experience with ALLETE, Inc. ("ALLETE") and Minnesota Power.

A. I am originally from Virginia, Minnesota, where I graduated from high school before attending college at Michigan Technological University. I hold a Bachelor of Science degree in Electrical Engineering. I obtained a master's degree in business administration with an emphasis in business operations from the Carlson School of Management at the University of Minnesota in Minneapolis in 2006. I completed requirements for obtaining Professional Engineers licensure in Minnesota in 2007 and have held a Minnesota Class A Master Electrician's license since 2004.

I began my career with Minnesota Power in 2006 as a Meter Engineer and later a Supervising Engineer of the Electric Meter Department, where I was responsible for providing project management and oversight for the Smart Grid Investment Grant project, which implemented Advanced Metering Infrastructure ("AMI") System technology within Minnesota Power's service territory, and managing work for technicians who maintain all metering systems. In 2013, I served as Manager of Technical Systems, where I was responsible for oversight of Substation Maintenance, Substation Construction, and Relay and Protection Systems. In this role, I also managed transmission substation asset management programs. I have also worked as the Manager of Distribution Resources, where I led our Distribution Services area—including line operations, operations planning, trouble, and dispatch—before being promoted to

Director of Distribution Operations in 2015. In 2019, I was promoted to Vice President of Transmission and Distribution, and in 2025 my role was realigned to Vice President of Transmission Planning and Operations with oversight of the transmission systems for Minnesota Power. This area includes approximately 55 employees.

Q. What is the purpose of the testimony you are presenting on behalf of Minnesota Power?

A. The purpose of my Direct Testimony is to provide background on the Company's transmission systems. I discuss the capital investments the Company has made since Minnesota Power's most recent rate case in 2023 in Docket No. E015/GR-23-155 ("2023 Rate Case") and the operation and maintenance ("O&M") necessary to continue to provide efficient and reliable electricity to Minnesota Power customers in a cost-efficient manner. I provide information to support the Company's reasonable, necessary, and prudent investments in local and regional capital projects and ongoing maintenance of our transmission systems. I also provide testimony on the continued benefits of the Company's participation in the Midcontinent Independent System Operator, Inc. ("MISO") and how that participation impacts revenue and expenses for Minnesota Power. Finally, I provide testimony on the Company's continued efforts to improve reliability and system performance. The Company's distribution systems are discussed in the Direct Testimony of Company witness Joshua P. Goutermont.

Q. How is your testimony organized?

A. Section II of my Direct Testimony provides an overview of the Transmission work areas, explaining the role and the geographic reach of the transmission systems.

Section III provides both background and detail on the capital investments and projects in Transmission, including the types of projects and the work processes involved with them. This section also details the Transmission Cost Recovery ("TCR") Rider information specific to this filing, information on how the Company works to ensure renewable resources can interconnect to our system, and efforts related to regional transmission development.

Section IV of my Direct Testimony describes the O&M processes and costs for Transmission. This section also explains Minnesota Power's work on compliance items and third-party transmission revenues and expenses.

Finally, in Section V, I discuss Transmission's reliability and system performance, including a discussion on dynamic line rating programs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following schedules to my Direct Testimony:

- MP Exhibit ___ (Gunderson), Direct Schedule 1 – Minnesota Power Service Territory Map;
- MP Exhibit ___ (Gunderson), Direct Schedule 2 – Minnesota Power Transmission System Map;
- MP Exhibit ___ (Gunderson), Direct Schedule 3 – Duluth Loop Reliability Project Map; and
- MP Exhibit ___ (Gunderson), Direct Schedule 4 – Minnesota Power System Third-Party Transmission Revenue and Expense

II. TRANSMISSION WORK AREAS

Q. Please explain the role of Minnesota Power's Transmission department.

A. Minnesota Power's Transmission department is responsible for the construction, management, and O&M of Minnesota Power's transmission systems. This responsibility means that the department ensures that energy is safely and reliably transmitted from generating resources, whether Company-owned or third-party-owned, to the distribution system.

Q. What is the geographic reach of Minnesota Power's transmission system?

A. Minnesota Power's transmission system consists of, generally, voltages between 115 kilovolts ("kV") up to 500 kV. The Company's transmission system is located primarily in Minnesota and portions of North Dakota. These transmission facilities deliver power

from various generating resources, currently including wind, solar, coal, biomass, natural gas, and hydro. Minnesota Power's transmission facilities serve local loads across the Company's service territory, which spans nearly 26,000 square miles of central and northeastern Minnesota, and are critical to supporting the larger regional transmission system's overall reliability. A map of Minnesota Power's service territory is provided with my Direct Testimony as MP Exhibit __ (Gunderson), Direct Schedule 1. A map of the transmission system is provided as MP Exhibit ___ (Gunderson), Direct Schedule 2.

Q. Has the Company experienced changes to its Capital and O&M to advance EnergyForward since the 2023 Rate Case?

A. Yes. In the testimony that follows, I discuss grid transformation initiatives within the Capital and O&M areas of Transmission. Within the O&M section, I discuss factors considered in preparation of each work area's zero-based budget. This section also discusses increases in costs related to higher internal labor, contract labor, and material costs necessary to execute this work. While discussing the capital budgets, increases should be noted with similar labor factors and a much larger impact on costs as industry supply chain challenges continue.

Q. Can you please describe the changes to the overall procurement and planning processes used by the Transmission department in recent years?

A. Since 2020, and as discussed in my Direct Testimony in the 2023 Rate Case, the Transmission department has seen challenges related to planning, asset management, system performance, and supply chain as well as an increase in requests to interconnect to the Transmission System.

The majority of the challenges of the recent past were the convergence of large regional planning activities, local planning activities related to aging assets, and increased requests for interconnection. Minnesota Power is not alone in experiencing these challenges as utilities regionally and nationally have seen similar increases in demand for transmission projects, which has created demand challenges in critical areas of the

supply chain such as circuit breakers and transformers. These challenges related to procurement are also discussed in the Direct Testimony of Company witness Diana C. McFadden.

In response to these challenges, the Company has responded by augmenting staff in key areas related to transmission expansion including Transmission Planning, Transmission System Performance, and System Operations as study needs and operating needs have increased drastically since 2021. As the Company has moved into construction of critical transmission assets, operating the system optimally to reduce overall congestion while safely constructing has been a key objective for the team. The Company has also embarked on several system optimization projects that will be discussed later in my testimony. However, these challenges also have real cost impacts for the Company and our customers.

III. TRANSMISSION CAPITAL INVESTMENTS AND PROJECTS

A. Budget Process

Q. How is the capital budget developed?

A. The Company maintains a long-range capital investment plan based on identified needs and priorities; analyzing, assessing, and prioritizing projects is the first step in determining their necessity and timing, which informs the annual capital budget. The annual capital budget process employs a zero-based budgeting process, explained in more detail in the Direct Testimony of Company witness Joshua G. Rostollan. This process affirms the projects that are required within a specific year for the Transmission and Security work areas. The project assessments include personnel and public safety; compliance and legal requirements; reliability; cost recovery; financial payback; efficiency and cost savings; and impact on Company strategy. The project assessments also include overall project value; timing of external entity needs driving the project; timing of system capacity needs associated with the project; magnitude of customer load and number of customers that benefit from the project; the necessary start date for project execution based on the project schedule and workflow; and the date when any

relevant compliance requirements become effective. Generally speaking, there are two phases to the annual capital budget process.

Q. Please describe the first phase.

A. During the first phase of the annual capital budget process, each area reviews its long-range plan ("LRP") in conjunction with expected spending and necessary timing and identifies the projects to move to the next phase. Along with the LRP, the biennial Integrated Distribution Plan ("IDP"), the Minnesota Biennial Transmission Projects Report (the "Biennial Report"), the annual MISO Transmission Expansion Plan ("MTEP"), and the Integrated Resource Plan ("IRP") are fundamental budget and reporting tools that may be used during the budgeting process. The IDP provides guidance on the Company's distribution system and highlights continuous foundational investments related to serving customers, ensuring reliability, and preparing for a more resilient grid; the Biennial Report and the MTEP provide information about projects to address identified transmission needs; and the IRP reports how the Company will meet the expected energy needs of customers with a reliable, safe, cost-effective, and increasingly clean supply of energy.

Q. What occurs during the second phase?

A. The second phase involves cross-functional organizational review, where leadership and subject matter experts from Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, Fleet, Customer Experience, and Wildfire Management work areas collaborate on the review of proposed projects with a cross-functional lens. If not already identified through the Company's normal project scoping processes, projects that may be coordinated with one another to improve efficiency or that impact multiple areas are identified, and plans are made to allocate the necessary resources and align their schedules. Resource and budgetary constraints are also considered during this review stage. Once consensus over the portfolio of projects is achieved, the cross-functional group moves the portfolio forward to the Portfolio Review Board ("PRB") for approval. The PRB consists of leadership across the represented areas. The resulting capital budget must also receive management approval

and is then compiled into the annual corporate capital budget presented for review and approval to the ALLETE Board of Directors.

Q. Does the budgeting process ensure that capital investments are reasonable and necessary?

A. Yes. This budgeting process results in a reasonable budget for capital investments needed to maintain the safety and reliability of the transmission and distribution system. Additionally, this budget ensures the prudent investment of capital to provide electric service to our customers; provide necessary upgrades to the regional transmission system; comply with North American Electric Reliability Corporation ("NERC") reliability requirements and other policy drivers; meet system capacity needs; and ensure the health of existing assets.

Q. Please describe the PRB.

A. The PRB provides governance, control, and recommendations to senior management for the portfolio of capital projects led by the Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, Fleet, Customer Experience, and Wildfire Management work areas. The PRB is responsible for reviewing the capital additions and removals to ensure that projects proposed are consistent with the Company's long-range strategic plans. The PRB is charged with seeking additional information or project budget development details from the appropriate work areas before approving a project. The PRB governs the review and approval of capital projects, budget, scope, and expenditure changes, along with bridging potential sequencing gaps between areas and communication of project execution controls and metrics such that critical project goals set forth by senior leadership are achieved. This group also fills an advisory role to senior leadership regarding the performance of capital projects.

Q. How are capital projects managed once they are approved?

A. Each project is assigned a project manager who is responsible for the efficient delivery of the project. As the leader of the project, the project manager coordinates with subject

matter experts to ensure project scope, schedule, and budget are well defined and the appropriate resources are allocated to each project. As the project progresses from initiation to design to construction, the project manager monitors and controls the project and communicates to the PRB any expected changes to scope, schedule, or cost.

Q. How is the capital budget monitored throughout the year?

A. Each month, the capital additions portfolio is reviewed and actual costs are compared to budget at the project level from both a financial perspective and performance perspective. Any variances impactful to a project are immediately addressed and communicated to leadership. Project forecasts are reviewed monthly to maintain a steady and dependable flow of financial information regarding capital expenditures. This process of monitoring the capital budget throughout the year ensures prudent management of Company resources.

Q. Are changes to projects sometimes necessary after initial budgets have been established?

A. Yes. Project budgets and forecasts are regularly reviewed throughout the year to ensure they reflect the most current information available. As projects progress, circumstances may change that require updates to project scope, cost estimates, timing, or resource requirements. Examples of project changes include:

- Refinement of early-stage planning estimates as engineering, design, and project details become more fully developed.
- Resolution or reduction of previously identified project risks, resulting in the release of contingency funds that are no longer needed.
- Changes to project schedules due to procurement lead times, supply chain constraints, contractor availability, or equipment delivery delays, which may require work to be accelerated or deferred between calendar years.
- Modifications to project scope, resource requirements, or contractor pricing identified during project execution.
- Supply chain, equipment and materials pricing.

- Emergence of unplanned but necessary work, including activities driven by customer service requirements, reliability needs, regulatory obligations, or external factors such as local government infrastructure projects.

This ongoing review process helps ensure that project forecasts remain accurate and that capital resources are allocated efficiently to meet customer and system needs.

Q. Please describe the process the Company undertakes to manage project changes and break-in projects after establishing a capital budget.

A. The PRB reviews and manages capital spending, project risks, and project contingency levels. The PRB reviews quarterly reports for financial performance and progress of high-spend or high-risk projects. The PRB also reviews all changes and associated impacts to the overall portfolio. Certain project changes—such as commodity and construction pricing, government requirements, customer electric requirements, line outage limitations, and supply chain delays—often fall outside of the Company's control. If overall portfolio deviations fall outside of an acceptable level, the PRB will make recommendations to meet financial targets. Changes to the annual forecast are reported to the accounting area, which also monitors capital spending.

Q. Please describe current capital budget risks and the Company's approach to managing risk after establishing a capital budget.

A. Over the last few years, the Company has experienced unprecedented uncertainty around capital projects relating to the risks of a changing and challenging supply chain but also has developed a tremendous amount of experience in considering supply chain and cost changes in this environment. Due to the growth in electricity demand attributed to a variety of reasons including electric vehicles, artificial intelligence ("AI") and hyperscale data centers, domestic industrial reshoring and the demand for those products, the Company is facing greater lead times for major materials, increased costs for these materials, labor constraints, and global manufacturing dependencies. The Company is also facing risk due to tariffs and global conflicts impacting supply chains

with increased pricing and delays. This is discussed in greater detail in the Direct Testimony of Company witness McFadden.

In addition to challenging procurement schedules, the Company is experiencing increased difficulty in coordinating construction outages within available outage windows due to the availability of the labor workforce, both internally and externally, which could result in modifications to project completion schedules or increased costs due to multiple mobilizations and demobilizations. Beyond coordination around outages, commitments with external contractors have increased risk due to multiple MISO project sequencing, along with an increase in overall base projects.

In this current environment, the Company continues to work diligently to identify ways to mitigate some of these risks for the benefit of customers. Mitigation efforts include: increased monitoring of inventory levels for major and commonly procured materials; utilizing vendor alliances for both materials and services to assist in monitoring supply chain impacts and proactively identifying alternate material and backup suppliers; and bulk ordering earlier in the process to secure production timeslots. Further, because this environment has existed for a few years, the Company has developed a better understanding of where the risks in the marketplace might arise and how best to consider those at the front-end of project planning and adapt during project implementation.

Q. How are final decisions made with respect to canceling, delaying, or accelerating a transmission project?

A. The Company's portfolio of capital projects is reviewed monthly. Projects with risks are flagged and monitored closely by the project manager. If the project manager indicates the project may fall outside of allowed variances, the project is reassessed by the business unit. Both Company and customer needs are balanced with resource availability. If one project is delayed or cancelled, other projects may be accelerated to maintain the overall capital budget as well as resource and customer commitments. Proposed changes to the portfolio of projects are reviewed and approved by the PRB,

which is expected to manage capital additions to the approved capital budget, and which manages the Company's resources efficiently.

Q. Do you anticipate any changes to the overall capital budgeting process for the Transmission department based on the holding company restructuring proposed by the Company?

A. No.

Q. Please explain why it may be necessary for the Company to replace projects it has identified in a test year with other projects during the pendency of a rate case.

A. Minnesota Power has identified and budgeted for certain capital projects to be placed in service in the 2027 test year. Because the Company must provide safe, reliable, and cost-efficient energy to customers, shifting in-service dates of certain projects may be necessary to meet changing needs. Maintaining some flexibility to replace projects within a test year is in the best interest of customers for several reasons, including the ability to respond to change in a timely, safe, and cost-effective way. By adapting to change, the Company can ensure safe and reliable transmission and delivery of electricity to customers.

The Commission has previously allowed such flexibility in shifting projects, recognizing that the utility industry is a dynamic business and priorities change.[1] In doing so, the Commission has allowed substitution projects where: (1) the utility has shown the replacement projects are necessary, the costs are prudent, and the projects will be in service in the test year; and (2) the other parties had sufficient time to review the proposed replacement projects.[2] Therefore, the Company will provide updates on

[1] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 13 (Feb. 28, 2023) (eDocket No. 20232-193486-01); *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 22–23 (Mar. 12, 2018) (eDocket No. 20183-140963-01); *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 26–27 (May 8, 2015) (eDocket No. 20155-110264-01).

[2] *Id.*

any such changes, the reasons for the change, and any budget updates in Rebuttal Testimony. The Company requests that the Commission recognize the dynamic nature of this aspect of the Company's business as it has done in prior cases, including the 2023 Rate Case.[3]

Q. Has the Distribution department's budget process changed at all with the acquisition of ALLETE's outstanding stock by Canada Pension Plan Investment Board and Global Infrastructure Partners?

A. No.

Q. Does the Company currently anticipate to place all projects in the 2026 projected fiscal year into service before the end of 2026?

A. Yes. At this time, all projects in the 2026 projected fiscal year are planned to be in-service before the end of 2026. If any of them are not placed into service until early 2027, Minnesota Power does not anticipate any impact to those projects in the 2027 test year.

Q. Will all the projects included in the 2027 test year be placed into service during 2027?

A. At this time, the Company is on track to place all capital projects identified in the 2027 test year budget in service in 2027 based on current design, permitting, and procurement milestones. However, there may be extenuating circumstances, such as those mentioned above, that necessitate modifications to the overall projects that Minnesota Power places in service during 2027, although the Company manages such circumstances to ensure the overall portfolio remains balanced.

[3] *In the Matter of the Application of Minn. Power for Auth. to Increase Elec. Serv. Rates in Minn.,* Docket No. E015/GR-23-155, ORDER ACCEPTING AND ADOPTING AGREEMENT SETTING RATES at 6 (Nov. 25, 2024) (eDocket No. 202411-212388-01).

Q. What has the Company's Transmission and Security capital investment looked like from 2023 through 2027?

A. Table 1 provides the Company's regulated capital plant additions for 2023, 2024, and 2025 actuals, the 2026 projected fiscal year, and the 2027 Proposed Test Year for the Transmission and Security areas. Table 1 provides this information at the Total Company level. Capital plant additions at the Minnesota Jurisdictional level are provided in Table 2.[4]

Q. Before turning to those tables, how would you summarize the capital additions in Tables 1 and 2, for purposes of your work areas?

A. As described above, many capital projects are cross-functional and include asset additions of varying types. General Plant assets exist at every transmission substation or facility. Some substations contain both transmission and distribution assets. For efficiency, the Company defines its capital projects by site, such that all of the impact assets at the site, whether Transmission, Distribution, General, or Intangible Plant (Cyber Technology Services, Security, etc.), are assessed as part of one overall project, assigned to a single project manager, and engineered and constructed in close coordination through this synchronized approach. The Company reflects the entire bundle of work included in such projects in one managing area in Table 1 based on which classification has the majority of additions for the particular project. This is a demonstration of the intricacies in budgeting that the Company undertakes in any year, but most notably in the development of a test year.

Many projects have capital additions to more than one classification, such as both Transmission and Distribution. One example from the 2027 test year where the Company will encounter these combinations of assets is the Hat Trick Substation Expansion, as described in the Direct Testimony of Company witness Goutermont. This project adds both Transmission and Distribution assets for which the Company budgets, and for which the Company identified in the various classifications for purposes of

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

providing the necessary financial supporting information to the Commission. Therefore, classifying capital additions for projects like this one, particularly when the Company develops its test year budgets, is a painstaking and detailed process in which many factors are considered. These projects are illustrative of the inherent interconnectedness of the Company's operations, wherein some assets are not necessarily readily unbundled and obviously delineated from each other at the time of project initiation.

Table 1. Regulated Capital Plant Additions (Including Contra Allowance for Funds Used During Construction ("AFUDC")) (Total Company)

Capital Plant Additions (including Contra)—Total Company	2023	2024	2025	2026	2027
Transmission, General Plant, and Intangible	**Actual**	**Actual**	**Most Recent Fiscal Year**	**Projected Fiscal Year**	**Proposed Test Year**
Transmission*	**$11.4**	**$83.0**	**$55.7**	**$74.6**	**$62.3**
Asset Management	$3.2	$55.0	$32.9	$25.0	$19.3
Baseline Reliability	-	-	-	$0.9	$20.7
Externally Driven	$0.9	$0.1	($0.3)	-	-
Strategic	-	-	-	-	$21.0
Strategic/Duluth Loop	-	$17.5	$22.5	$48.7	$1.3
Strategic/Growth	$0.2	$6.3	$0.4	-	-
Strategic/North Shore Loop	$7.1	$4.2	$0.1	-	-
Security	**$0.8**	**$0.3**	**$0.3**	**$0.3**	**$0.1**
Transmission Total, excluding Riders	**$12.2**	**$83.3**	**$56.0**	**$74.9**	**$62.4**

Amounts in millions.

Amounts may not total due to rounding.

**Amounts may include Intangible & General Plant Additions.*

Table 2. Regulated Capital Plant Additions AFUDC (MN Jurisdictional)

Capital Plant Additions (including Contra)—Total Company	2023	2024	2025	2026	2027
Transmission, General Plant, and Intangible	**Actual**	**Actual**	**Most Recent Fiscal Year**	**Projected Fiscal Year**	**Test Year**
Transmission*	**$9.3**	**$68.9**	**$46.1**	**$61.3**	**$48.0**
Asset Management	$2.6	$45.6	$27.5	$20.5	$14.9
Baseline Reliability	-	-	-	$0.8	$16.0
Externally Driven	$0.8	$0.1	($0.2)	-	-
Strategic	-	-	-	-	$16.2
Strategic/Duluth Loop	-	$14.5	$18.4	$40.0	$1.0
Strategic/Growth	$0.2	$5.2	$0.3	-	-
Strategic/North Shore Loop	$5.8	$3.5	$0.1	-	-
Security	**$0.7**	**$0.3**	**$0.3**	**$0.3**	**$0.1**
Transmission Total, excluding Riders	**$10.0**	**$69.2**	**$46.4**	**$61.6**	**$48.1**

Amounts in millions.

Amounts may not total due to rounding.

**Amounts may include Intangible & General Plant Additions.*

B. Transmission Investments and Projects

Q. What are the main categories of Transmission projects as the Company develops its long-range plan and capital budgets?

A. Transmission projects are divided into four general categories: Baseline Reliability Projects, Transmission Asset Management Projects, Externally-Driven Projects, and Strategic Projects. These categories correspond to the unique sets of drivers and sources of identification associated with various types of transmission projects in Minnesota Power's long-range plan.

Q. How do projects in each of these categories get incorporated into the Company's long-range plan?

A. The Company maintains a long-range transmission project plan that incorporates all four categories of transmission projects. Transmission Asset Management Projects are included in the long-range plan on an annual basis, generally assuming similar year-to-

year spend for Contingency Programs and based on specific identified projects and priorities for Asset Renewal Programs. Baseline Reliability Projects, Externally-Driven Projects, and Strategic Projects are initially included in the long-range plan based on the anticipated need date indicated by the identified need for the project.

For Baseline Reliability Projects, the need date most often corresponds to the model-year in which it was first identified in the annual MISO Transmission Expansion Plan ("MTEP") assessment. For Externally-Driven Projects, the need date corresponds to the timing given by the external entity driving the need for the project. For Strategic Projects, the need date corresponds to the Company's anticipated timing for the particular strategy initiative causing a need for the project.

Projects may then be shifted, when possible, within the long-range plan to optimize cash flow, constructability, and internal resource loading. This type of shifting depends on the relative flexibility of need dates and is not always possible. As project scopes become more well defined nearer to the need date, the cost estimate, cash flow, and timing of a project included in the long-range plan is refined. As applicable, transmission projects in the Company's long-range plan are reported in the MISO MTEP process and the Biennial Report.

Q. Please explain the initiation and scoping process for each type of transmission project.

A. Once a project has been identified through the evaluation processes discussed above, the project enters an initiation phase, where the project team is assigned, and several planning activities occur to develop the baseline project scope, schedule, and budget. The initial project scope is defined by the Transmission and Distribution Planning Department and further refined through input from various departments such as Project Management, Substation Engineering, Transmission Line Engineering, Safety, Security, Relay and Maintenance Engineering, Meter Engineering, Communications Infrastructure, Distribution Engineering, System Operations, Construction and Maintenance, and Environmental Permitting and Land Management. These departments

provide input about preliminary project engineering, required permits or approvals, coordination with external entities, project location and layout, construction sequencing, supply chain lead times, safety and security considerations, and project risks to determine the formal project scope, schedule, and budget for the project. Depending on the nature of the project, including permitting requirements and equipment lead times, the timeline from initial project scoping to project completion may be anywhere from three to ten years.

Q. What are Baseline Reliability Projects?

A. Baseline Reliability Projects are transmission system upgrades necessary to ensure the transmission system complies with the Company's transmission planning criteria. Such criteria may establish acceptable pre- or post-contingent voltages, transmission line loading, or stability performance, among other things.

Q. What are the main drivers for Baseline Reliability Projects?

A. The main drivers for Baseline Reliability Projects are deviations from the Company's planning criteria identified pursuant to the NERC transmission planning standards.

Q. How are Baseline Reliability Projects identified?

A. Baseline Reliability Projects are typically identified through the annual transmission planning assessments required under the applicable NERC Reliability Standard. These assessments are typically completed by MISO in coordination with the Company. Through the annual MTEP study process, the Company submits proposed projects, reviews power flow models, provides contingency definitions, and evaluates study results. If a need is identified in the MTEP assessment, the Company submits a corrective action plan to MISO. In some cases, the corrective action plan may involve the operation of an existing Remedial Action Scheme, an existing Operating Guide, or reconfiguration by system operators. In other cases, the corrective action plan for the condition may be a new Baseline Reliability Project.

Q. How does the Company augment the MISO MTEP review process for planning purposes?

A. The Company augments its involvement in the MTEP process and refines its list of Baseline Reliability Projects through internal targeted evaluation of criteria violations identified in the MTEP assessment. Where significant issues are identified in the MTEP assessment related to the Company's transmission system, the Company will often perform its own targeted study of the local area to further refine its understanding of the issue and potential solutions. The internal study yields a deeper understanding of the issue, its causes, and potential solutions, driving the process toward a particular Baseline Reliability Project that may be scoped and incorporated into long-range planning and capital budgeting activities to be implemented at the proper time.

Q. How does the Company evaluate alternatives for Baseline Reliability Projects?

A. Depending on the type of issue and its magnitude, the Company considers a broad range of alternatives for Baseline Reliability Projects. Alternatives evaluation is typically performed during the internal targeted study phase described above. Alternatives considered may include both traditional and non-wire solutions, including, among other things, establishing new operating guides or procedures (including load management), upgrading or reconfiguring existing transmission facilities, building new transmission facilities, and implementing new transmission- or distribution-connected supply-side solutions. The types of alternatives considered for a particular issue are dependent on the nature of the problem to be addressed. To be a viable alternative, a solution must be available (1) at the necessary time, (2) with the necessary response, and (3) for the necessary duration, to address the issue at hand.

For example, if the issue is a voltage collapse caused by an unanticipated transmission line outage, any viable solution must be capable of being in-service and online or running prior to, during, and after the unanticipated outage independent of any operator intervention. For an issue such as this, certain types of operating guides and peaking or intermittent power supply resources would not be sufficient to solve the problem

because they could not be counted upon to be running prior to, during, and after the unanticipated outage or capable of responding rapidly enough to mitigate the collapse.

Q. How does the Company coordinate evaluation of non-wire solutions in Transmission Planning along with its existing Resource Planning activities?

A. Where a non-wire solution is determined to be a viable alternative for a Baseline Reliability Project or other transmission system issue, scoping-level information about the non-wire solution (necessary size, location, and operational characteristics) will be developed by Transmission Planning and discussed with Resource Planning to facilitate further development of the non-wire solution. Where appropriate, Resource Planning will further develop the non-wire solution by identifying an anticipated cost, implementation timeline, power supply benefits, societal benefits, and other potential benefits specific to that non-wire alternative. If any non-wire alternatives identified through this exercise show potential benefits for the transmission system and customers, are economical compared to other alternatives from a holistic utility planning perspective, and can be implemented on a timeline sufficient to satisfy the identified transmission system issue, these alternatives could be considered as resource options for implementation.

When reasonable, a non-wire alternative can be considered in the Company's current IRP,[5] and then a petition requesting approval for implementation could move forward. If the non-wire resource option does not fit with the timing of the current IRP analysis, then it can be considered in the next IRP submittal or a separate petition. If the transmission system issue needs to be addressed on a timeline prior to the next IRP approval, then additional requirements could be included in the development of the solution to address the resource fit and timing. The Company also considers the role of non-wire alternatives on the distribution system in its most recent IDP.[6] This process of integrated system planning allows for a more holistic approach to the system as a whole.

[5] *In the Matter of Minn. Power's Application for Approval of its 2025-2039 Integrated Resource Plan*, Docket No. E015/RP-25-127, INITIAL FILING (Mar. 3, 2025) (eDocket No. 20253-215986-11).
[6] *In the Matter of Minn. Power's 2025 Integrated Distribution Plan*, Docket No. E015/M-25-140, COMPLIANCE FILING (Nov. 3, 2025) (eDocket No. 202511-224624-01).

Q. What Baseline Reliability Projects are included in the 2026 projected fiscal year and 2027 test year?

A. Baseline Reliability projects include the Dynamic Line Ratings Program within the 2026 projected fiscal year and the Badoura 230 kV Modernization Project within the 2027 test year.

Q. What is the Dynamic Line Ratings Program and what will it address?

A. The Company's Dynamic Line Ratings ("DLR") Program involves the installation of 52 Heimdall Power neurons across six transmission line facilities, including three identified in the Minnesota 2025 Grid Enhancing Technologies Study in Appendix B of the Biennial Report (Docket No. E999/M-25-99), which have historically experienced congestion due to system limitations. This is the Company's first implementation of a dynamic line ratings system. The neurons are installed directly onto the conductors of the energized transmission lines. Once installed, the devices continuously monitor and report real-time physical and electrical conditions, providing a clearer picture of how much electricity can safely flow through the power line conductors at any given moment. This technology can unlock capacity to relieve congestion and reduce costs.

Q. What is the Badoura 230 kV Modernization Project and what will it address?

A. The Badoura 230 kV Modernization Project involves modifications to the existing Badoura 230 kV/115 kV Substation to replace the existing 230 kV/115 kV transformer and convert the 230 kV bus to a ring bus configuration. The project is needed to increase the rating of the 230/115 kV transformer, add circuit breakers to mitigate contingencies causing transmission line overloads in the surrounding system, and address age and condition issues at the substation. The Badoura 230 kV Modernization Project was included in the 2025 Biennial Report (Docket No. E999/M-25-99) under tracking number 2019-NE-N8 (as "Badoura 230/115 kV Transformer Replacement"). Construction is expected to begin in 2026 with completion to occur by the end of 2027.

Q. What are Transmission Asset Management Projects?

A. Transmission Asset Management Projects include: (1) Contingency Programs and (2) Asset Renewal Programs. Contingency Programs provide funding for emergency restoration and replacement of failed assets due to unforeseen events. Asset Renewal Programs provide funding for planned replacements or upgrades where priority assets have been identified in advance of equipment failure.

Q. What are the main drivers for Transmission Asset Management Projects?

A. The primary driver for all Transmission Asset Management Projects is the age and condition of existing equipment on the transmission system. Asset Renewal Programs are intended to ensure safety and reliability, enhance long-term planning, and optimize asset lifecycle value through the proactive replacement or upgrade of certain types of high-priority, high-impact, and/or high-value assets. Contingency Programs are intended to enable the Company to respond to unanticipated failures that occur throughout the year. While Contingency Programs respond on an as-needed basis and are necessary, the goal of the overall Transmission Asset Management Program is to maximize the life of all transmission equipment and, in most cases, repair or replace that equipment as part of an Asset Renewal Program at or near the end of the equipment's useful life and ahead of the Contingency Program.

Q. How are Transmission Asset Management Projects identified?

A. Transmission Asset Management Projects are generally identified by historical operating experience, facility age and condition data, and through the judgment of subject matter experts and cross-functional project teams. Contingency Programs are generally similar from year to year and the funding level is based on recent experience with the particular type of asset they are intended to address. Asset Renewal Programs are developed to enhance lifecycle asset management across the fleet of transmission assets methodically and intentionally over a defined period of time. Asset Renewal Programs are typically coordinated with a cross-functional group of internal subject matter experts to identify, prioritize, and scope replacements or upgrades of high-priority, high-impact, or high-value assets. The Company's current practice is to

maintain substation and transmission line modernization programs designed to efficiently and holistically address all asset renewal and known long-term reliability needs for a given substation or transmission line with one comprehensive project. Additionally, Minnesota Power has strategically taken a more methodical approach to identification of asset management projects—the Company is able to leverage its experience to identify equipment and other assets that are nearing the end of life for replacement or renewal, instead of waiting for equipment to begin to experience operational issues before replacement.

Q. What Transmission Asset Management Projects are included in the 2027 test year?

A. Transmission Asset Management Projects in the test year include asset renewal and contingency programs for substation equipment such as transmission circuit breakers, relay panels, and power transformers; asset renewal and contingency programs for transmission line equipment such as poles and hardware; and asset renewal and contingency programs for the Company's High Voltage Direct Current ("HVDC") assets. For clarification, "Asset Management" is a broad term that encompasses contingency plus targeted projects and, in some cases, may also encompass asset renewal elements. The term "Asset Renewal" is generally used with reference to targeted projects that involve replacing old equipment with new equipment. Aside from regular annual programs, the Forbes 230 kV Modernization Project is a specific larger Asset Renewal Project in the test year.

Q. What is the Forbes 230 kV Modernization Project and what will it address?

A. The Forbes 230 kV Modernization Project involves modifications at the existing Forbes 230 kV/115 kV Substation to replace an aging 230 kV/115 kV transformer, 230 kV capacitor bank, circuit breakers, switches, relay panels, and associated equipment. The project is needed to increase the rating of the 230 kV/115 kV transformer, add circuit breakers to mitigate contingencies causing transmission line overloads in the surrounding system, and address age and condition issues at the substation. Among other things, the scope of work will address an oil-filled circuit breaker and 230 kV/115 kV transformer from 1979, an early-generation sulfur hexafluoride circuit breaker with

known operational concerns, and an existing capacitor bank with failed components. The replacement of these assets will be accompanied with site and reliability improvements including increased reactive capability in the capacitor bank, an improved emergency rating for the transformer, and updates to the aging site infrastructure. The Forbes 230 kV Modernization Project was included in the 2025 Biennial Report (Docket No. E999/M-25-99) tracking number 2019-NE-N12. Completion of the initial phase of construction will require the replacement of one (1) 230 kV circuit breaker, fifteen (15) 230 kV switches, one (1) 230 kV capacitor bank, along with replacing five (5) and modifying four (4) relay panels and replacing additional miscellaneous equipment in the electrical equipment enclosure and is expected to take place in 2027. A second phase requiring replacement of a 230 kV/115 kV transformer is planned for 2028, but none of those costs are within the 2027 test year. A final third phase to replace another 230 kV circuit breaker is planned for 2029, but none of those costs are within the 2027 test year.

Q. What are Externally-Driven Projects?

A. Externally-Driven Projects are transmission system modifications or upgrades necessary to facilitate the needs of external (i.e., non-Minnesota Power) entities, such as the following: customers; federal, state, or local agencies; new generators; or other utilities. Examples include transmission line relocations due to changes in other infrastructure, system modifications required by NERC outside of the NERC transmission planning standards, and facilitating third-party transmission system access pursuant to Federal Energy Regulatory Commission ("FERC") open access transmission service rules.[7] Externally-Driven Projects are generally identified in response to a request by an external entity. To further manage external requests, the Company has formalized and improved its transmission interconnection process to ensure that open-access requests for transmission interconnection are subject to a rigorous stepwise process to identify system impacts, network upgrades, and

[7] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Serv. by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Util., Docket Nos. RM95-8-000 and RM94-7-001, FERC ORDER 888 (Apr. 24, 1996).

interconnection scope of work and appropriately assign the costs to the external requestor. New generation interconnection requests on the Company's transmission system follow a similarly rigorous interconnection process under the MISO Tariff, which is wholly administered by MISO. There are no externally-driven projects in the 2027 test year.

Q. How does the Company manage transmission interconnection requests?

A. In the last two years, the Company has experienced an unprecedented volume of requests to connect to or modify the Company's transmission system. In response, the Company formalized and is now maintaining a Transmission Interconnection Queue ("Queue"), which currently includes eighteen active requests that are at different phases of the Company's transmission interconnection request process.

Q. Describe the Company's transmission interconnection request process generally.

A. The Company's transmission interconnection request process is described on its website at www.mnpower.com/Company/TransmissionInterconnectionProcess.

The steps in the transmission interconnection process are listed below:

1. Request Form: Requestor submits a Transmission Interconnection Request Form to the Company. This form details the request, including a description of the proposed interconnection or modification to the Company's transmission, the megawatt addition, the location, and the requested in-service date.
2. System Impact Study Agreement ("SISA"): The Company sends the requestor a SISA to sign and return. The SISA details the items that are to be included in the System Impact Study report. Under the SISA, which is funded by the requestor, the Company completes a System Impact Study to identify system impacts and network upgrades necessary as a result of the request. Upon completion of the System Impact Study, the requestor must either notify the Company of its intent to move forward with a Facility Study or withdraw its request from the Queue.

3. Facility Study Agreement ("FSA"): An FSA is sent to the requestor to sign and return. The FSA details the items that are to be included in the Facility Study report, including interconnection facilities and any network upgrades identified in the System Impact Study. Under the FSA, which is funded by the requestor, the Company completes preliminary engineering to define the scope, schedule, and estimated cost of interconnection facilities and network upgrades required for the requested interconnection. Upon completion of the Facility Study, the requestor must either notify the Company of its intent to move forward with a Facility Construction Agreement ("FCA") or withdraw its request from the Queue.

4. FCA: The FCA details obligations and responsibilities pertaining to the construction of the interconnection facilities and network upgrades identified in the Facility Study report, including the responsibility of the requestor to fund all interconnection facilities and network upgrades identified in the FCA. Depending on the circumstances, there could be interim agreements at this step of the process, such as an Engineering and Procurement Agreement ("E&P"), to enable engineering and long lead-time material procurement to proceed in parallel with the development of the FCA. The requestor is responsible for all transmission upgrade costs associated with an E&P Agreement and an FCA. Once an FCA is executed, the FCA is filed at FERC, the project is reported into the MISO MTEP process, and the Company designs and constructs the project(s) consistent with the FCA.

5. Interconnection Agreement ("IA"): The IA is the final step in the interconnection process, which is required prior to energizing the interconnection facilities constructed under the FCA. The IA governs the ongoing operation, maintenance, and coordination of the interconnection.

The Queue is managed on a first come, first served basis, with limited exceptions. When the Company receives a signed SISA from the requestor, the project then is assigned a number in the Queue. Interconnection requests advance in the Queue at the cost and discretion of the requestor as the required payment and security milestones are met for

each step of the process. The requestor and the Company may agree to modify or reduce the scope and size of an interconnection request based on study results as it moves from SISA to FSA to FCA. At each stage, the Company's obligation is limited to the scope and size of the request as specified and funded by the requestor at the time, and all costs incurred are the responsibility of the requestor.

Q. How are the costs of Externally-Driven Projects shared between the Company and the external entity driving the need for the project?

A. In general, the costs for all externally-driven projects that are subject to the Company's transmission interconnection Queue process are exclusively the responsibility of the requestor under the terms of the FCA. Prior to the formalization of the Queue process and in certain unique circumstances, cost responsibility for Externally-Driven Projects may have varied depending on the situation. For certain projects coordinated with Great River Energy, the utilities have agreed to bear the costs for the facilities they own and determine ownership of new projects in a way that corresponds to benefits received and facilitates overall revenue neutrality between the two utilities. Transmission revenue sharing with Great River Energy is governed by the Joint Pricing Zone ("JPZ") Agreement, which is discussed further in Section IV.C of my Direct Testimony. The JPZ Agreement was extended in 2023, and FERC accepted the Amended and Restated JPZ Agreement between Great River Energy and the Company (MISO Rate Schedule 47).

Q. What Externally-Driven Projects are included in the 2027 test year?

A. There are no Externally-Driven Projects included in the 2027 test year.

Q. What are Strategic Projects?

A. Strategic Projects are transmission system upgrades related to larger Company initiatives such as generation fleet transition. Like Baseline Reliability Projects, Strategic Projects are necessary to resolve deviations from the Company's transmission planning criteria. Planning criteria violations may include pre- or post-contingent voltage issues, transmission line overloads, or stability issues, among other things.

Q. What are the main drivers for Strategic Projects?

A. The main drivers for Strategic Projects, like Baseline Reliability Projects, are deviations from the Company's planning criteria, identified pursuant to NERC transmission planning standards. The difference between Strategic Projects and Baseline Reliability Projects is that Strategic Projects are associated with a change on the transmission system that is due to a Company-driven initiative.

Q. How are Strategic Projects identified?

A. Unlike Baseline Reliability Projects, Strategic Projects are most often identified first through the Company's own internal transmission planning studies. Where a strategic initiative is being evaluated, the transmission system impacts of that initiative are determined from an internal targeted evaluation of the potential changes associated with the initiative. The internal targeted evaluation is used to evaluate different scenarios pertaining to the strategic initiative being considered (for example, different combinations of generator retirements) and the system impacts of those scenarios are captured. Where system impacts result in needs, potential solutions to those issues are considered through a similar alternatives evaluation as was described previously under Baseline Reliability Projects. Both traditional and non-wire solutions are considered as appropriate. This internal study process ultimately results in a potential Strategic Project (or set of Strategic Projects) for which preliminary cost estimates may be developed and incorporated into the Company's overall evaluation of the strategic initiative. Where a need has been identified through such a study, Strategic Projects will continue to be evaluated and refined through further internal studies—and eventually through the MTEP assessment process—as more definition develops around the nature and timing of the Company strategic initiative.

Q. What Strategic Projects are included in the 2027 test year?

A. The Strategic Projects included in the 2027 test year include the North Dakota HVDC Transmission Line 900 MW Upgrade and the Duluth Loop Reliability Project.

Q. What is the North Dakota HVDC Transmission Line 900 MW Upgrade and what will it address?

A. The North Dakota HVDC Transmission Line 900 MW Upgrade involves structure and conductor replacements in North Dakota necessary to increase the rating of the Company's HVDC Line from 550 MW to 900 MW. To complete the rating increase, a similar project is planned to take place in Minnesota in subsequent years. Increasing the transmission line rating will enable maximum utilization of the existing transmission line infrastructure concurrent with the separate replacement of the HVDC converter stations as part of the Company's HVDC Modernization Project. Upon completion of the Transmission Line Upgrade projects and the Modernization Project, the Company's HVDC Line will be capable of transferring 900 MW directly from North Dakota to the Company's customers in Minnesota. The North Dakota HVDC Transmission Line 900 MW Upgrade project is being completed pursuant to Transmission Service Requests ("TSRs") the Company filed with MISO to formally increase the capacity of the HVDC Line. The project was included in the 2025 Biennial Report (Docket No. E999/M-25-99) under tracking number 2013-NE-N17 (as "HVDC 900 MW Transmission Line Upgrades"). Completion of the upgrades in North Dakota are expected to take place in 2027, with a subsequent Minnesota phase planned for construction in 2028. Only the upgrades to the line expected to take place in 2027 are included in the 2027 test year.

Q. What is the Duluth Loop Reliability Project and why is it needed?

A. The Duluth Loop Reliability Project[8] includes: (1) construction of about 14 miles of new 115 kV transmission line between the Ridgeview, Haines Road, and Hilltop Substations; (2) construction of a new one-mile extension connecting an existing 230 kV transmission line to the Arrowhead Substation; (3) upgrades to the Ridgeview, Hilltop, Haines Road, and Arrowhead substations; and (4) reconfiguration, rebuild, and upgrade to existing transmission lines and communications infrastructure in the project

[8] *In the Matter of the Application of Minn. Power for a Certificate of Need for the Duluth Loop Reliability Project*, Docket No. E015/CN-21-140, APPLICATION FOR A CERTIFICATE OF NEED AND ROUTE PERMIT (Oct. 21, 2021) (eDocket No. 202110-179004-03); *Notification of Intent to File a Route Permit Application for the Duluth Loop Project Pursuant to the Alt. Permitting Process*, Docket No. E015/TL-21-141, APPLICATION FOR A CERTIFICATE OF NEED AND ROUTE PERMIT (Oct. 21, 2021) (eDocket No. 202110-179004-04).

area. The Duluth Loop Project is needed to replace the system support once provided to this area by coal-fired baseload generators located along Minnesota's North Shore, in an area of the system known as the North Shore Loop. The Duluth Loop is a network of 115 kV transmission lines and substations at the south end of the North Shore Loop which form two parallel connections between the 230 kV/115 kV transmission source at the Arrowhead Substation and the North Shore Loop connection at the Colbyville Substation. Many customers in the Duluth area are served from substations connected to the Duluth Loop—including customers in Hermantown, Duluth Heights, Kenwood, Woodland, Lakeside, Hunter's Park, and Congdon—as well as the areas around the Miller Hill Mall, the Duluth International Airport, the universities, and the downtown hospital district, among others. The Duluth Loop Reliability Project will address severe voltage stability concerns, relieve transmission line overloads, and enhance the reliability of Duluth-area transmission sources—all of which are needs that have resulted from the retirement of these generation sources.

The Duluth Loop Reliability Project has been reported in the Biennial Report since 2019 under tracking number 2019-NE-N12, and a combined Certificate of Need and Route Permit Application for the Project was submitted to the Commission under Docket Nos. E015/CN-21-140 and E015/TL-21-141, respectively, on October 21, 2021. The Commission subsequently granted the Certificate of Need and Route Permit for the Duluth Loop Project on April 3, 2023. Construction of the Duluth Loop Reliability Project began in September 2023, with the project to be placed in service in 2026.

Q. What other Strategic Projects has the Company undertaken in recent years?

A. Strategic Projects undertaken in recent years are generally related to the transition of the Company's baseload coal generation fleet and resource mix. Most projects have been located in or adjacent to the North Shore Loop and are related to Company decisions to cease coal-fired operation and retire, idle, or convert generators to peaking operation. The Duluth Loop Reliability Project is directly related to these decisions. While there are no projects in the test year related to the future ceasing of coal-fired operations at the Company's Boswell Energy Center ("BEC") Units 3 ("BEC3") and 4 ("BEC4") or

the broader regional transmission planning implications of the clean energy transition in MISO as epitomized by the MISO Long Range Transmission Plan ("LRTP") Tranche 1 and Tranche 2.1 portfolios, I have also included a discussion of the local and regional impacts of these issues for overall transparency and context of the Company's planning efforts.

Q. What is the North Shore Loop?

A. The North Shore Loop refers to an approximately 140-mile portion of 115 kV transmission lines in the northeastern Minnesota transmission system.[9] The North Shore Loop extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Two Islands Switching Station near the former site of the now retired Taconite Harbor Energy Center ("THEC") near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center ("Laskin") near Hoyt Lakes. The North Shore Loop transmission system is used by Minnesota Power and Great River Energy to serve customers in an area extending from Duluth to the Canadian border to the eastern end of the Iron Range—including east Duluth, Two Harbors, Silver Bay, Grand Marais, Hoyt Lakes, and the surrounding areas. The North Shore Loop transmission system is shown in MP Exhibit ___ (Gunderson), Direct Schedule 3. I have discussed aspects of the North Shore Loop in my Direct Testimony in prior rate cases.

Q. How has the North Shore Loop changed in recent years?

A. Historically, the North Shore Loop contained an abundance of coal-fired baseload generation, including Laskin and THEC, as well as a large industrial cogeneration facility located in Silver Bay. The Silver Bay generators are owned by Silver Bay Power Company, a subsidiary of Cleveland-Cliffs, Inc. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites were idled, retired, or converted to peaking operation. In 2015, the two units at the

[9] Historically, the North Shore Loop also included 138 kV transmission lines. The 138 kV operating voltage was removed from Minnesota Power's transmission system upon completion of the Laskin – Taconite Harbor Voltage Conversion Project in 2023 (Biennial Plan Tracking Number 2017-NE-N2).

Laskin Energy Center were converted from coal-fired baseload units to natural gas capacity units. Also in 2015, Minnesota Power retired one of the units at THEC.[10]

With Commission approval in the 2015 IRP (Docket No. E015/RP-15-690), Minnesota Power idled the other two THEC units in the fall of 2016 and ceased coal-fired operations at the facility in 2020.[11] The remaining two THEC units were retired in March 2023 as approved by the Commission in Minnesota Power's 2021 IRP (Docket No. E015/RP-21-33) (the "2021 IRP"). In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, in September 2019, Silver Bay Power Company idled both of the Silver Bay units and began operating with no generators online. The cumulative impact of these operational changes has effectively "decarbonized" the North Shore Loop, leaving no baseload generators normally online in an area of the system that was originally designed in the mid-1900s to support customers with redundant baseload coal generation.

Q. What are the transmission impacts of the transition away from local baseload generators in the North Shore Loop?

A. The local baseload generators at Laskin, THEC, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing redundancy, voltage support, and power delivery capacity, among other things. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016. These projects are necessary to ensure the continued reliability of the transmission system in the area by replacing the inherent redundancy that was lost with the idling and retirement of multiple coal fired generation units, addressing unacceptably low voltage and voltage stability concerns, and mitigating transmission line and transformer overloads. The projects have been progressively implemented throughout the transition

[10] See *In the Matter of Minn. Power's 2013-2027 Integrated Res. Plan,* Docket No. E015/RP-13-53, ORDER APPROVING RESOURCE PLAN, REQUIRING FILINGS, AND SETTING DATE FOR NEXT RESOURCE PLAN at Order Point 3 (Nov. 12, 2013) (eDocket No. 201311-93582-01).

[11] See *In the Matter of Minn. Power's 2016-2030 Integrated Res. Plan*, Docket No. E015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATION at Order Point 3 (July 18, 2016) (eDocket No. 20167-123403-01).

of the North Shore Loop generators to ensure that the right projects are implemented at the right time to support the continued reliable operation of the transmission system. Where project implementation timelines were difficult to align with fleet transition decisions, the Company took the necessary steps to ensure operating guides or temporary solutions were implemented to support transmission reliability. Upon the completion of the Duluth Loop Reliability Project in 2026, the Company's planned projects related to the decarbonization of the North Shore Loop will be complete.

Q. What has the Company concluded from its evaluations of the transmission impacts from shutting down local baseload generators?

A. The transmission system is designed to be highly reliable and redundant, yet affordable. Where local baseload generators have provided reliability services to the local transmission system for many years, the transmission system is designed to rely on the local baseload generators being online. As long as the baseload generators were around to provide these reliability services, the cost of transmission upgrades that would decrease reliance on the generators was difficult to justify. With the removal of the local baseload generators, the transmission system in the surrounding area will require some modifications in order to offset the loss of the reliability services formerly provided by the generators. The more dependent the transmission system was on the generators, the more significant the upgrades are likely to be. In the case of the North Shore Loop, the Company found that the transmission system was dependent on the local baseload generators. Where the cost of transmission upgrades to decrease reliance on the local baseload generators was difficult to justify while the generators were running, those network upgrade costs are now necessary due to the series of generation fleet transition decisions that have taken place since 2015.

Q. What projects has Minnesota Power implemented to address fleet transition in the North Shore Loop, and what issues do these projects resolve?

A. Between 2016 and 2026, Minnesota Power has implemented, or is in the process of implementing, several projects throughout and adjacent to the North Shore Loop transmission system to address system impacts from fleet transition. These projects:

- Strengthen and increase the capacity of existing 230 kV/115 kV sources and transmission lines supplying the North Shore Loop;
- Replace the voltage regulation and voltage support capability formerly provided by the local baseload generators with new capacitor banks and a new static synchronous compensator; and
- Restore redundancy by eliminating single points of failure and establishing additional 115 kV transmission connections to the North Shore Loop.

Q. Do the projects included in this rate case and discussed in your testimony address all of the transmission system investments associated with fleet transition in the North Shore Loop?

A. Yes. The projects discussed in my Direct Testimony and projects implemented prior to the 2027 test year encompass the full portfolio of North Shore Loop projects identified by the Company. The North Shore Loop projects implemented in earlier years generally represented the most urgently required transmission system improvements. They addressed single-contingency issues that were either high-impact, high-likelihood, or both. These types of issues were addressed proactively in order to continue to operate reliably on a day-to-day basis with no North Shore Loop generators online.

While the last remaining baseload generating unit in the North Shore transitioned to a normally offline status in September 2019 and the THEC units ceased coal-fired operation in 2020, projects like the Duluth Loop Reliability Project have been in a process of implementation that will see completion in 2026. These projects generally address lost redundancy and related voltage or power delivery issues associated with multiple contingency events, for which either the risk profile is less severe than the single contingency issues mentioned above and/or the Company was able to devise temporary operational solutions to manage the risk, thus allowing sufficient time to implement long-term solutions.

The Duluth Loop Reliability Project specifically addresses issues of redundancy for which a long-term solution is necessary, but short-term impacts are able to be

managed—with increased risk due to the lost support from the generators—until the long-term solution may be implemented. The Duluth Loop Reliability Project will be the final transmission project directly related to the impacts of fleet transition in the North Shore Loop.

Q. What additional Strategic Project drivers has the Company identified as it prepares for the future of transmission grid needs?

A. In addition to the transmission planning practices and projects discussed so far in my testimony, several areas of additional study, coordination, and project development have taken place in recent years or are currently taking place to prepare for the future of transmission grid needs. The Company's 2021 IRP and 2025 IRP (Docket No. E015/RP-25-127) (the "2025 IRP") highlighted the extensive study work that the Company has undertaken to begin to understand the transmission impacts associated with changing operations of BEC3 and BEC4, which are the last remaining baseload generators on the Company's system and in all Northern Minnesota.

Q. What information is provided in the Company's 2021 and 2025 IRPs related to transmission impacts resulting from the changing operations of BEC3 and BEC4?

A. In its 2021 and 2025 IRPs and the Baseload Retirement Study included with the 2021 IRP, the Company described the significance of the BEC units and the support that they provide to the Northern Minnesota transmission system. The Company's conclusions about the BEC units in the 2021 IRP are described as "six pillars that are key to understanding the significance of BEC to the region and the transmission system impacts from changing operations at BEC."[12] The six pillars described in the 2021 IRP are: 1) Northern Minnesota is unique; 2) Baseload generator retirements require holistic replacements; 3) Baseload generators supply voltage support and system strength; 4) Dispatchable generators deliver power to the local area; 5) Dispatchable generators offset the need for regional power transfers; and 6) Solution development is a multi-year process. These principles are informed by the Company's experiences from the

[12] *In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E015/RP-21-33, INITIAL FILING at Appendix F at 40 (Feb. 1, 2021) (eDocket No. 20212-170598-03).

transition of smaller coal units in the North Shore Loop, as discussed previously in my testimony and in greater detail in Appendix F, Part 6 of the 2021 IRP. The six pillars are also informed and supported by a number of studies that have evaluated various types of transmission impacts associated with changing operations of the BEC units. The supporting transmission studies are described in the 2021 and 2025 IRPs, and an overview of conceptual solutions and costs for issues related to different types of changes in operation of the BEC units is also provided.

Q. Are any transmission projects related to the changing operations of BEC3 and BEC4 included in the 2027 test year?

A. No. The Company continues to evaluate the scope and timing of projects necessary to support continued reliable operation of the local transmission system as BEC3 and BEC4 cease coal-fired operations in 2030 and 2035, respectively. While many of the resulting projects have begun implementation, the in-service dates for these projects are anticipated to take place in 2028 or later. The Northland Reliability Project, discussed below, will address regional voltage and transfer capability concerns related to the ceasing of coal-fired operations at BEC. The Riverton STATCOM Project, which has an anticipated in-service date in 2028, will provide necessary steady state and dynamic voltage support when the BEC units are not online to support the transmission system.

Q. Are there any regional Strategic Projects the Company is currently working on?

A. Yes. On a regional level, the Company is an active participant with MISO in the LRTP effort and is in the process of developing several LRTP transmission projects identified in Tranche 1 and Tranche 2.1. The Northland Reliability Project,[13] an LRTP Tranche 1 project being developed jointly with Great River Energy, will address significant regional voltage stability issues related to the changing operations of the BEC units, along with other benefits identified by MISO as part of the Tranche 1 portfolio. The Company's other LRTP transmission projects include the Big Stone South – Alexandria

[13] *In the Matter of the Application of Minn. Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line Project*, Docket Nos. E015,ET2/CN-22-416 and E015,ET2/TL-22-415.

– Big Oaks 345 kV second circuit project,[14] the Iron Range – St. Louis County – Arrowhead ("ISA") 345 kV Project,[15] the Maple River – Cuyuna ("MRC") 345 kV Project,[16] and the Bison – Alexandria 345 kV second circuit project.[17] Working together, the LRTP regional transmission project portfolios are expected to deliver benefits in excess of their costs and ensure the transmission system is reliable, economic, and compliant in the future based on state and utility policy goals, projected conditions, and industry trends.

The Company has also recently begun construction on the HVDC Modernization Project, which will result in the modernization of its existing HVDC converter stations to provide reliable energy transfer capability and enhanced grid support for decades to come.

Finally, the Company continues to work with MISO and its neighboring utilities on transmission planning initiatives, like the upcoming MISO LRTP Midwest Study, that will be foundational to meeting the long-term needs of a continually evolving regional electric grid. These particular projects are not included in the Minnesota Jurisdiction Proposed Test Year 2027 but are discussed in my Direct Testimony to give an idea of the types of projects that the Company considers "Strategic."

[14] *In the Matter of the Application for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Docket No. E002, E017, ET2, E015, ET10/CN-22-538; *In the Matter of the Application for a Route Permit for the Alexandria – Big Oaks 345 kV Transmission Project in Central Minn.*, Docket No. E002, E017, ET2, E015, ET10/TL-23-159; *In the Matter of the Application for a Route Permit for the Big Stone South – Alexandria 345 kV Transmission Project*; Docket Nos. ET2, ET10, E015, E017, E002/TL-23-160.

[15] *In the Matter of the Application of Minn. Power and American Transmission Company, LLC for a Certificate of Need and Route Permit for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project*, Docket Nos. E015/CN-25-111 and E015/TL-25-112.

[16] *In the Matter of the Application of Minn. Power, Great River Energy, and Otter Tail Power Company for a Certificate of Need*, Docket No. E015,ET2,E017/CN-25-109; *In the Matter of the Application of Minn. Power, Great River Energy, and Otter Tail Power Company for a Route Permit*, Docket No. E015,ET2,E017/TL-25-110.

[17] *In the Matter of the Application for a Certificate of Need for the Bison to Alexandria Second Circuit 345 kV Transmission Line Project*, Docket No. E002,ET2,E015,E017,ET6135/CN-25-116; *Route Permit Amendment for the Bison to Alexandria Second Circuit 345 kV Transmission Line Project*, Docket No. E002,ET2,E015,E017,ET6135/TL-09-1056.

C. Security Projects and Investments

Q. What other categories of capital additions are listed in Table 1?

A. The Company also has capital additions for Security.

Q. What do the Security projects in Table 1 include?

A. Security projects include:

- Security Access Control Panel Programs (2026 and 2027) – Provide funding for planned replacement or upgrades where priority assets have reached their end of life or have been identified for replacement or upgrade in advance of equipment failure; and
- Security Contingency Projects (2026 and 2027) – Provide funding for emergency restoration and replacement of failed assets due to unforeseen circumstances.

D. Cost Recovery Rider

Q. Does the Company propose to move any investment recovery of transmission system capital investments from the TCR into rate base?

A. Yes. One project currently in the TCR, the Duluth Loop Reliability Project described in Section III.B of my Direct Testimony, will be in-service in late December 2026, and will be transferred from the TCR to recovery in base rates with the implementation of proposed rates. The Direct Testimony of Company witness Levi A. Peterson provides additional information regarding this accounting.

Q. Did Minnesota Power prudently incur the costs it spent to complete the Duluth Loop Reliability Project?

A. Yes. The costs incurred by the Company to complete the Duluth Loop Reliability Project were prudently and reasonably incurred to complete this necessary project. Minnesota Power estimates it will be able to complete this project near the midpoint of the project's original cost estimate at a total cost of $62.7 million (2021$) Total Company, after adjusting nominal costs to 2021 dollars using the Handy Whitman

factors. The total nominal cost of the project was $91.2 million Total Company ($70.3 million MN Jurisdictional) (2026$).

Q. What does the Company request the Commission do with the costs for the Duluth Loop Reliability Project?

A. Minnesota Power requests that the Commission allow the Company to remove the Duluth Loop Reliability Project from the TCR and include it in base rates as discussed further in the Direct Testimony of Company witness Levi A. Peterson.

Q. Are there any transmission projects that the Company is not moving from the TCR into base rates?

A. Yes. The HVDC Modernization Project, discussed in Section III.B of my Direct Testimony, will remain in the TCR. In proposing the HVDC Modernization Project, the Company also included two grants that Minnesota Power applied for to reduce the overall cost of the project to its customers. To that end, Minnesota Power was included in legislation in the 2023 session to receive $15 million for the HVDC Modernization Project, as proposed. On October 18, 2023, the Company was informed that this project could receive a $50 million grant from the U.S. Department of Energy ("DOE"). On October 2, 2025, and October 17, 2025, Minnesota Power received notice from the DOE stating that the DOE had terminated a $50 million grant originally selected for award October 18, 2023, for the HVDC transmission system project (the "Award"). On November 4, 2025, Minnesota Power submitted to DOE an informal dispute of DOE's termination of the Award pursuant to 2 C.F.R. 910.128(a). On March 16, 2026, Minnesota Power received from DOE a notice of final determination following informal dispute resolution in which the Department concluded the Award termination is rescinded and the grant re-instated. On March 19, 2026, the $50 million grant was formally reinstated.

Q. Are there any other transmission projects that the Company is constructing that are not in the TCR?

A. Yes. The Company is, or will be pending Commission approval, participating in the construction and ownership of various LRTP projects with estimated in-service dates beginning in 2030.[18]

IV. TRANSMISSION O&M

A. Budget Overview and Transmission FERC Accounts

Q. Please describe the Transmission annual O&M budget development process.

A. The consolidated annual budget process is described in the Direct Testimony of Company witness Rostollan. Each year, the work areas in Transmission (and related support services) prepares its budget using a zero-based (i.e., bottom-up) approach. The budget is typically submitted during the second quarter of the prior year.

Q. What factors are considered in preparation of each work area's zero-based budget development?

A. Transmission work areas develop their budgets through a collaborative zero-based budgeting process involving budget owners, budget analysts, and subject matter experts. This process evaluates the resources and expenditures necessary to safely, reliably, and efficiently operate and maintain the transmission system during the budget year. The process considers expected workload, asset maintenance requirements, system

[18] *In the Matter of the Application of Minn. Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line Project*, Docket Nos. E015,ET2/CN-22-416 and E015,ET2/TL-22-415; *In the Matter of the Application for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Docket No. E002, E017, ET2, E015, ET10/CN-22-538; *In the Matter of the Application for a Route Permit for the Alexandria – Big Oaks 345 kV Transmission Project in Central Minn.*, Docket No. E002, E017, ET2, E015, ET10/TL-23-159; *In the Matter of the Application for a Route Permit for the Big Stone South – Alexandria 345 kV Transmission Project*; Docket Nos. ET2, ET10, E015, E017, E002/TL-23-160; *In the Matter of the Application for a Certificate of Need for the Bison to Alexandria Second Circuit 345 kV Transmission Line Project*, Docket No. E002,ET2,E015,E017,ET6135/CN-25-116; *Route Permit Amendment for the Bison to Alexandria Second Circuit 345 kV Transmission Line Project*, Docket No. E002,ET2,E015,E017,ET6135/TL-09-1056; *In the Matter of the Application of Minn. Power, Great River Energy, and Otter Tail Power Company for a Certificate of Need*, Docket No. E015,ET2,E017/CN-25-109; *In the Matter of the Application of Minn. Power, Great River Energy, and Otter Tail Power Company for a Route Permit*, Docket No. E015,ET2,E017/TL-25-110; *In the Matter of the Application of Minn. Power and American Transmission Company, LLC for a Certificate of Need and Route Permit for the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Line Project*, Docket Nos. E015/CN-25-111 and E015/TL-25-112.

reliability and resiliency objectives, regulatory compliance obligations, workforce requirements, labor allocation between capital and O&M activities, contractor utilization, and anticipated changes in compensation and benefits. Historical spending and operational performance are reviewed to provide context, while known and measurable changes—including inflationary impacts, evolving NERC and FERC requirements, asset condition, technology investments, transmission system needs, and process improvement opportunities—are incorporated into the forecast. One-time or non-recurring events are normalized or excluded to ensure the budget reflects ongoing operating requirements. The resulting budget represents the level of O&M funding necessary to support the reliable operation, maintenance, and stewardship of the Company's transmission facilities and fulfill its obligations to customers and regional reliability organizations.

Q. How does the Company incorporate FERC Accounts into its O&M budget process?

A. Budget information is reviewed by FERC Account rather than primarily focusing on work areas and cost types. As functions shift between work areas or leadership, a departmental view does not provide effective trend data. The Company places significant emphasis on FERC Account budgeting and data validation, as core functions will retain the same FERC Accounts regardless of the Company reporting structure.

Q. Please describe the key functions within the Transmission organization that are included in the annual Transmission O&M budget.

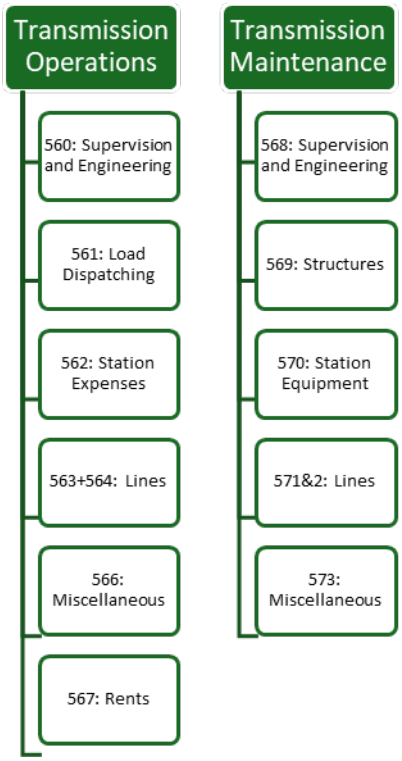
A. The annual Transmission O&M budget supports the safe, reliable, and compliant operation of the Company's transmission system. Budgeted activities include inspection, maintenance, repair, and operation of transmission assets, including overhead lines, substations, and communication facilities. The budget also includes vegetation management activities necessary to maintain transmission rights-of-way, engineering and system planning functions, transmission system studies, and real-time system operations. In addition, the budget supports compliance with applicable NERC reliability standards and FERC standards of conduct. These activities are essential to

maintain system reliability, support customer service, and respond to both planned and emergent system needs.

Q. What FERC Accounts are included as major transmission expenses?

A. Figure 1 provides the FERC Accounts included as major Transmission O&M expenses.

Figure 1. Transmission FERC Accounts



Q. Why is FERC Account 565 omitted from Figure 1?

A. Because FERC Account 565 is primarily associated with the MISO Tariff and budgeted based on external inputs from MISO, it will be discussed separately from the other FERC O&M Accounts for the Transmission work area. FERC Account 565 is discussed in Section IV.C of my Direct Testimony.

Q. What is the 2027 test year budget for major Transmission O&M expenses?

A. Table 3 provides Total Company actual and budgeted expenses from 2023 through 2025, 2026 projected year expenses, and test year 2027 expenses. Minnesota Power has

budgeted $33.9 million Total Company ($25.7 million MN Jurisdictional) in the 2027 test year, which is an increase of $5.5 million Total Company ($3.0 million MN Jurisdictional) from 2025 actual expenses. This increase is primarily due to Dispatch Services, Load Dispatch, Vegetation Management Overhead Lines, Operation Supervision, Communication Equipment, and anticipated upgrades of leased transmission lines and substation equipment owned by Superior Water Light and Power ("SWLP"), discussed in further detail below. Table 4 provides these amounts at the Minnesota Jurisdictional level.

Table 3. Transmission Budget and Actual Expenses by FERC Account (Total Company)

Account	2023 Actual	2024 Actuals	2025 Most Recent Fiscal Year Actual	2026 Projected Fiscal Year	2027 Proposed Test Year	2027 Proposed Test Year vs 2025 Actual
560	$3.3M	$3.0M	$2.8M	$4.5M	$3.8M	$1.0M
561	$8.3M	$8.8M	$8.3M	$10.3M	$10.8M	$2.4M
562	$0.1M	$0.0M	$0.1M	-	-	($0.1M)
566	$0.6M	$0.7M	$0.5M	$0.4M	$0.5M	-
567	$3.4M	$3.6M	$4.1M	$4.4M	$4.4M	$0.3M
569	$2.5M	$2.4M	$2.4M	$3.1M	$3.1M	$0.7M
570	$5.0M	$5.6M	$5.3M	$3.6M	$4.7M	($0.7M)
571	$4.8M	$5.0M	$4.8M	$4.9M	$6.7M	$1.9M
Total	**$27.9M**	**$29.1M**	**$28.4M**	**$31.2M**	**$33.9M**	**$5.5M**

Table 4. Transmission Budget and Actual Expenses by FERC Account (MN Jurisdictional)

Account	2023 Actual	2024 Actual	2025 Most Recent Fiscal Year Actual	2026 Projected Fiscal Year	2027 Proposed Test Year	2027 Proposed Test Year vs 2025 Actual
560	$2.7	$2.5	$2.0	$3.4	$2.5	$0.5
561	$6.8	$7.3	$6.7	$8.5	$8.4	$1.7
562	$0.1	-	-	-	-	-
566	$0.5	$0.6	$0.4	$0.3	$0.4	-
567	$2.8	$3.0	$3.4	$3.6	$3.4	-
569	$2.0	$1.9	$1.9	$2.5	$2.2	$0.3
570	$4.1	$4.6	$4.4	$3.0	$3.6	($0.8)
571	$4.0	$4.1	$3.9	$4.1	$5.2	$1.3
Total	**$23.0M**	**$24.0M**	**$22.7M**	**$25.4M**	**$25.7M**	**$3.0M**

Q. Do you anticipate any changes to the overall O&M budgeting process for the Transmission department based on the Company's proposed holding company reorganization?

A. No.

Q. Please describe the costs in Account 561 Load Dispatch.

A. Account 561 captures the costs associated with load dispatch and system control operations, encompassing reliability coordination, load forecasting, contingency analysis, and the real-time and next-day monitoring of the transmission system to ensure reliable service. Cost components include labor, employee benefits, payroll taxes, materials, outside services, and other related operating expenses. The increase of $2.4 million Total Company ($1.7 million MN Jurisdictional) from 2025 actuals to the 2027 test year is driven primarily by three factors: (1) higher transmission services expense, reflecting increased MISO schedule and demand charges; (2) elevated transmission regulatory and business support costs, largely attributable to rising NERC and Midwest Reliability Organization ("MRO") assessment fees and additional contractor spend; and (3) increased internal labor and associated benefits and overhead costs driven by higher salaries and wages.

Q. Please describe the costs in Account 571 Maintenance of Overhead Lines.

A. Account 571 is for Maintenance of Overhead Lines, which includes labor, materials used, and expenses incurred in maintenance of transmission plant. The increase of $1.9 million Total Company ($1.3 million MN Jurisdictional) from 2025 actuals to the 2027 test year is primarily due to an increase in vegetation management spending. Vegetation Management work is described in detail in the Direct Testimony of Company witness Goutermont. Transmission maintenance is similar to the approaches taken to maintain the distribution system.

Q. Please describe the costs in Account 560 Operation Supervision and Engineering.

A. Account 560 is for Operation Supervision and Engineering, which includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, and expenses incurred in the general supervision and direction of the operation of the transmission system as a whole. The increase of $1.0 million Total Company ($0.5 million MN Jurisdictional) from 2025 actuals to the 2027 test year in this account is primarily driven by departmental strategies to optimize the maintenance of assets by shifting internal resources from capital to O&M focused, as well as continued but renewed focus on employee safety and training programs.

Q. Please describe the costs in Account 569 Maintenance of Structures.

A. Account 569 is for Maintenance of Structures, which includes cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, materials used, and expenses incurred. The increase of $0.7 million Total Company ($0.3 million MN Jurisdictional) from 2025 actuals to the 2027 test year is primarily due to higher than historical external contractors and increased internal labor and associated benefits and overhead costs driven by higher salaries and wages.

Q. Please describe the costs in Account 567 Rents.

A. Account 567 is for Rents and includes a lease expense paid to SWLP in accordance with the Transmission Asset Lease Agreement ("TALA") approved by the Commission in Docket No. E015/AI-08-1297. Through the TALA, the Company leases all 115 kV

transmission lines and substation equipment owned and operated by SWLP. As capital additions and associated operating costs of these assets change, the lease payment will change accordingly. The TALA defines the methodology for calculating the Minnesota Power expense for leasing the SWLP transmission system assets. The Company has included $4.4 million Total Company ($3.4 million MN Jurisdictional) in the 2027 test year, reflecting capital additions by SWLP and the calculation methodology included in the TALA.

B. Compliance

Q. What is the regulatory oversight for bulk power system reliability?

A. Maintaining bulk power system reliability involves compliance with NERC Reliability Standards. In 2007, FERC granted NERC the legal authority to enforce reliability standards on all users, owners, and operators of the bulk power system, including Minnesota Power, in accordance with Section 215 of the Federal Power Act. NERC delegates its authority to monitor and enforce compliance to regional entities established across North America. Collectively, NERC and the regional entities are known as the Electric Reliability Organization ("ERO"). The MRO is the regional entity that oversees Minnesota Power's compliance with NERC Reliability Standards. Annual funding for NERC and the MRO is provided primarily through assessment fees to load-serving entities including Minnesota Power. These assessments are allocated on a net-energy-for load basis. As of October 15, 2026, there are roughly 72 NERC Reliability Standards consisting of over 1,280 standard requirements and sub-requirements applicable to Minnesota Power, with 16 new or revised standards coming into effect in 2027 and 2028.

Q. How does Minnesota Power approach its NERC compliance obligations?

A. Minnesota Power's NERC compliance program is designed to achieve safe, reliable, secure system operation and reinforce high standards of performance in meeting compliance obligations. This includes striving to meet its compliance obligations with professionalism and effectively responding when noncompliance occurs. Through an open culture of compliance, Minnesota Power thoroughly investigates instances of

potential noncompliance, reports the instances to the MRO, and implements mitigating activities to reduce the risk of reoccurrence. Meeting NERC compliance obligations is an ongoing effort: in 2024 and 2025 employee time averaged 12,834 hours annually for general NERC compliance activities. This does not include time spent on regular departmental processes that include some aspects of NERC compliance.

Minnesota Power also takes proactive actions to improve its compliance procedures and plan for the future through participation in NERC's standards development process and industry involvement. Minnesota Power participates in most applicable Standards balloting and commenting opportunities. This not only allows Minnesota Power to influence the requirements of the Standards, it provides the Company's subject matter experts advance knowledge to plan for implementing the new or revised requirements.

Minnesota Power's subject matter experts stay apprised of compliance best practices and trends through participation in ERO & industry webinars and conferences, the Mid-Continent Compliance Forum ("MCCF"), and the North American Transmission Forum ("NATF").

The MCCF is a non-profit organization dedicated to providing a platform for NERC compliance professionals to come together, share knowledge, and participate in industry events. The MCCF typically offers forum meetings twice a year to share information among compliance professionals. A Company employee is a member of the MCCF Board of Directors.

The NATF's mission is to promote excellence in the safe, reliable, secure, and resilient operation of the electric transmission system, with a vision to continuously improve electric transmission system reliability, security, and resiliency, while ensuring the safety of utility personnel. The NATF offers peer collaboration and best practice guidance to member participants in a variety of practice areas and working groups. Minnesota Power has over 90 employees who participate in one or more of 25 practice groups and working groups. To further its continuous improvement efforts, Minnesota

Power hosted an NATF Peer Review in May 2026. A Peer Review is a comprehensive peer-to-peer evaluation of a NATF member's procedures, practices, and processes. Conducted by a team of subject matter experts from other member organizations and industry peers, the program is designed to identify strengths, highlight exemplary practices, and uncover opportunities for improvement across a range of topic areas. Minnesota Power's 2026 Peer Review focused on five topics: Human Performance Improvement, Operations Tools, Cyber Security, System Protection, and Vegetation Management. Minnesota Power is currently evaluating the results of the Peer Review to determine next steps and priorities.

Q. Describe some of NERC's current initiatives, how NERC plans to address them, and how this may impact Minnesota Power's future compliance obligations.

A. NERC periodically assesses and prioritizes risks to the bulk power system and uses those assessments to develop strategic initiatives to address higher-priority risks. Two of those strategic initiatives are Inverter-Based Resources ("IBRs"), and the Large Loads Action Plan.

The growth of IBRs such as wind, solar, and battery generation and its impact on bulk power system reliability has been a focus of NERC efforts for several years. In 2026, NERC completed its IBR Registration initiative, creating new functional registrations for generation owners and operators of smaller IBRs that are deemed to have an impact on the grid but do not meet the criteria to be Bulk Electric System assets. Minnesota Power has one site, the Taconite Ridge wind farm, that meets the criteria for the Company to register for these new Category 2 Generator Owner ("GO") and Generator Operator ("GOP") functions. NERC has eleven Standards development projects related to IBRs in various stages of completion that span 17 new or revised Reliability Standards that are applicable to GOs and/or GOPs for traditional Category 1 IBRs and/or the new Category 2 IBRs. Ten of these new or revised Standards became effective in 2026, the remainder have future implementation dates or are still under development. Minnesota Power must meet these new or revised requirements for its

existing IBR assets and for new wind, solar, and battery storage sites that meet NERC's criteria as Bulk Electric System assets or Category 2 assets.

NERC is implementing its Large Loads Action Plan in response to increasing numbers of large commercial and industrial loads that are rapidly connecting to the bulk power system. These include data centers and other types of large loads. NERC issued two Alerts, one in 2025 and one in 2026, to provide recommendations to and gather information from utilities about their practices and procedures related to large loads. In the second half of 2026, NERC plans to develop registry criteria for a new large load / computational load functional registration and begin standards drafting projects for new or revised Reliability Standards that will be applicable to the new registrants as well as the utilities who serve them. Minnesota Power has a long history of success in maintaining reliability with its large power customers' unique load characteristics. However, NERC's new registration criteria and Standards will bring new requirements for the Company and may also impact existing and future customers.

C. Third-Party Transmission Revenues and Expenses

Q. What is the purpose of this section of your Direct Testimony?

A. I am including this section of my Direct Testimony to provide an understanding of the Company's third-party transmission revenues and expenses. This section describes the operations associated with the interconnectivity of transmission facilities in Minnesota and the upper Midwest.

Q. Please describe the inter-utility connectivity of transmission facilities in Minnesota and the upper Midwest.

A. Electric utilities in Minnesota serve retail service areas that are spread throughout the state, sometimes non-contiguous to other parts of their retail service areas. Minnesota Power serves the residents of Duluth, Grand Rapids, Virginia, Little Falls, and many other communities in northern and central Minnesota through both retail and resale electric service, while other utilities serve the predominantly rural areas between the Company's territories. Electric utilities in Minnesota and the upper Midwest (e.g.,

investor-owned, cooperatives, transmission owners, and municipal utilities) have worked together for many years to develop a transmission network that will serve the various customer loads in this area. As a result, electric utilities in Minnesota and the region have highly interconnected transmission facilities that do not necessarily follow the patchwork of retail service area boundaries. This cooperation benefits the Company's customers by providing the transmission infrastructure needed to serve its loads at a lower cost than if the Company and neighboring utilities each independently constructed facilities to reach their respective service area loads.

Q. How does this interconnectivity of the transmission system affect the costs to Minnesota customers?

A. As designed and implemented, the jointly developed multi-owner transmission grid in Minnesota has resulted in less duplication of facilities and increased system efficiency. This has resulted in lower costs to customers than they would have otherwise seen if systems were developed independently instead of through collaborative efforts of the owners.

Today, access to that multi-owner transmission grid is available under the MISO Tariff, which dictates how revenues and expenses must be accounted for within the transmission system. Essentially, the Company receives revenue from other entities that use the Minnesota Power transmission system, thus reducing the revenue required from Minnesota Power's customers. The Company also incurs an expense for using the transmission systems of other entities. Minnesota Power accounts for these third-party transmission revenues and expenses predominantly in FERC Accounts 456 and 565, respectively.

Q. Please describe MISO and its role with respect to the transmission system.

A. The Company is a transmission-owning member of MISO. This means that, while Minnesota Power owns and maintains transmission assets, MISO operates the combined system, including Minnesota Power's assets, in conjunction with the transmission systems of more than 50 transmission owners. Furthermore, MISO establishes: (1) the

process and rules for wholesale customers to access the transmission system on a non-discriminatory basis; (2) the annual transmission planning process for expanding or upgrading the regional transmission system, which includes the Minnesota Power transmission system (i.e., MISO MTEP as discussed in Section III of my testimony); and (3) the policies and procedures that provide for the allocation of costs incurred to construct certain transmission upgrades and the distribution of revenues associated with those costs. Through MISO and in compliance with the MISO Tariff, wholesale revenues and third-party expenses are charged and recovered, accordingly.

Q. What is the value of the Company being a MISO member?

A. According to the most recent MISO Value Proposition report, MISO members receive $21 in benefits for every dollar spent on MISO membership in market efficiencies and regional coordination. These benefits include improved reliability, compliance, energy and ancillary services, renewable resource optimization, resource capacity and demand response according to the MISO Value Proposition Report.[19]

Q. How are wholesale revenues and third-party expenses recovered?

A. The MISO Tariff recovers the costs of transmission facilities through rates established and billed by "pricing zones." These pricing zones roughly match the boundaries of the local balancing authority areas operated by individual MISO member utilities. The local balancing authority areas closely resemble the control areas from the pre-MISO operational days. Control areas were used to designate transaction schedules and system dispatch responsibilities to specific utilities. When the transmission owners first began interconnecting, control area boundaries were established to roughly encompass a utility's transmission and generation assets. The concept of control areas (now local balancing authority areas) is still used for utility energy accounting purposes.

The concept of a pricing zone is that the "network loads" within the pricing zone, including a utility's retail native load customers, will bear the Annual Transmission

[19] MISO, *Value Proposition*, https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/ (last accessed Oct. 15, 2026).

Revenue Requirement ("ATRR") associated with the transmission facilities in the zone on a load ratio share basis. The ATRR is calculated using the transmission cost of service rate formula set forth in the MISO Tariff for each transmission owner.

Q. What pricing zone is Minnesota Power's load located in?

A. Minnesota Power load is located in the Minnesota Power pricing zone. There are, however, transmission facilities owned by and load served by Great River Energy included in that zone as well. As explained further below, the Minnesota Power system incurs third-party transmission expenses in the zone through a JPZ Agreement developed to compensate Minnesota Power and Great River Energy for facilities in the Minnesota Power pricing zone.

Q. How does the billing work?

A. The Company is party to a JPZ Agreement for the Minnesota Power pricing zone. Under this agreement, the transmission-owning utilities are compensated for their facilities in the zone, and the load serving utilities are billed for their loads in the zone. Because Minnesota Power is both a transmission owner and a load serving entity in the Minnesota Power pricing zone, the Minnesota Power System (1) receives revenues for the use of its facilities in the Minnesota Power pricing zone and (2) incurs expenses for its loads in the zone.

Furthermore, as a MISO transmission owner, Minnesota Power collects third-party wholesale transmission service revenues for others' use of the Company's system under both the MISO Tariff and other wholesale transmission agreements. The Minnesota Power system also incurs transmission and/or ancillary expenses for its load.

Q. What are the third-party transmission revenues and expenses applicable to base rates in the 2027 test year?

A. As shown in MP Exhibit ___ (Gunderson), Direct Schedule 4, the 2027 test year includes $92.2 million Total Company ($71.1 million MN Jurisdictional) of transmission revenues and $68.9 million Total Company ($53.2 million MN

Jurisdictional) of transmission expenses, net of costs recovered and revenues shared through Minnesota Power's TCR Rider.

Q. How does the 2027 test year compare to 2025 actuals for the amounts applicable to base rates?

A. The 2027 test year third-party transmission revenues exceed expenses applicable to base rates by $23.3 million Total Company ($17.9 million MN Jurisdictional) whereas the 2025 actual third-party transmission revenues exceeded expenses applicable to base rates by $19.9 million Total Company ($16.2 million MN Jurisdictional).

Q. What are the main drivers impacting the differences between 2025 actuals and the 2027 test year budget third-party transmission revenues and expenses applicable to base rates?

A. The 2027 test year third-party transmission revenues are $30.9 million Total Company ($20.8 million MN Jurisdictional) higher than 2025 actuals. The 2027 test year third party transmission expenses are $27.5 million Total Company ($19.1 million MN Jurisdictional) higher than 2025 actuals.

The difference between 2025 actuals and the 2027 test year budget amounts can be attributed to the inclusion of Attachment N1- HVDC Modernization revenues and expenses. The HVDC Modernization project is to upgrade existing terminals connected to the Company's 465-mile-long Square Butte HVDC 550 MW transmission line. The project would interconnect the upgraded HVDC terminals to the existing alternating-current transmission system. The purpose is to construct new HVDC converter stations and interconnection facilities to replace aging infrastructure and mitigate system outages due to increasing converter equipment failures. Attachment N1 increases revenues in the 2027 test year by $40.9 million Total Company ($31.6 million MN Jurisdictional) compared to 2025 actuals which does not have any Attachment N1 revenues and expenses.

Q. Do the 2027 transmission expenses and revenues in base rates include charges under MISO Schedules 26 and 26A to recover the costs of investments by MISO members recovered through the Regional Expansion Criteria and Benefits ("RECB") tariff mechanism?

A. No. Schedules 26 and 26A of the MISO Tariff provide for cost recovery of certain transmission projects. Schedule 26 recovers from MISO loads the costs of projects determined to be eligible for partial regional cost recovery as a "reliability" or "economic" project under the RECB mechanisms. Schedule 26A recovers from MISO loads the costs of projects determined to be eligible for full regional cost recovery as a Multi-Value Project. The Company includes MISO Schedules 26 and most 26A charges in the TCR Rider recovery mechanism. Schedules 26 and 26A charges would thus be in addition to the third-party transmission expenses described in my testimony. As approved by the Commission in the Company's 2025 TCR[20] and requested in the 2026 TCR,[21] Schedule 26A charges for the Company's LRTP projects are excluded from the TCR and assigned to the FERC jurisdiction. The Company also includes Schedules 26, 37, and 38 revenues in the TCR Rider as an offset to Schedules 26 and 26A expenses paid to MISO. Also as approved by the Commission in the Company's 2025 and 2026 TCRs, all Schedule 26A revenues for the Company's LRTP projects are excluded from the TCR and assigned to the FERC jurisdiction. These amounts are detailed in MP Exhibit ___ (Gunderson), Direct Schedule 4. A summary of the various MISO Schedules and impacts on revenues and expenses is provided in Table 5.

[20] *In the Matter of Minn. Power's Petition for Approval of its 2026 Rate Adjustment Mechanism Under its Rider for Transmission Cost Recovery*, Docket No. E015/M-25-433, ORDER at Comments of the Department of Commerce at 6 (July 8, 2026) (eDocket No. 20267-233888-01).

[21] *In the Matter of the Petition for Approval of a Transmission Cost Recovery Rider*, Docket No. E015/M-26-315, 2027 FACTOR PETITION at 35 (Aug. 25, 2026) (eDocket No. 20268-235748-01).

Table 5. Summary of MISO Schedules

Schedule Number and Description	Schedule Type	Transmission Owner (Revenue Received)	Transmission Customer (Expense Paid)
Schedule 1: Scheduling, System Control and Dispatch	Ancillary Service	X	X
Schedule 7: Long-Term and Short-Term Firm Point-To-Point Service *	Base Transmission	X	X
Schedule 8: Non-Firm Point-To-Point Transmission Service **	Base Transmission	X	X
Schedule 9: Network Integration Transmission Service ***	Base Transmission	X	X
Schedule 10: ISO Adder & FERC Annual Charges Recovery	Admin Schedule		X
Schedule 26: Network Upgrade Charge from Transmission Expansion Plan	Cost-Shared Projects	X	X
Schedule 26A: Multi-Value Project Usage Rate	Cost-Shared Projects	X	X
Schedule 35: HVDC Agreement Cost Recovery Fee	Admin Schedule		X
Schedule 37: MTEP Project Cost Recovery for ATSI Zone	Cost-Shared Projects	X	
Schedule 38: Allocation of Annual Revenue Requirements to the DEO/DEK Zone	Cost-Shared Projects	X	
Schedule 45: Cost Recovery of NERC Recommendation or Essential Action Charge	NREAC	X	X

* Border Owner Exemption

** Minnesota Power typically does not use Schedule 8 Non-Firm Transmission Service but would be charged accordingly under the tariff in the event it was reserved.

*** Minnesota Power does not pay MISO for Network Transmission Service because of the Bundled Load exemption. Network Transmission Service charges are imputed, however, for the purpose of the JPZ Agreement with Great River Energy.

Q. Please describe the 2027 Minnesota Power system third-party transmission revenues and expenses.

A. There are several types of third-party revenues and costs summarized in MP Exhibit ___ (Gunderson), Direct Schedule 4. These are Minnesota Power system transmission costs necessary to serve Minnesota Power system loads, including Minnesota Power retail native loads, pursuant to rate schedules accepted for filing by FERC:

- JPZ Costs – As I previously discussed, the Minnesota Power system incurs costs for serving its native loads within the Minnesota Power JPZ. The Company and Great River Energy own transmission facilities and serve loads in the Minnesota Power pricing zone and are compensated for each other's use of the transmission facilities to serve their respective loads through an agreed-upon methodology. The Company's transactions consist of both expense and revenue components, with expenses for the Company's use of the Great River Energy transmission facilities to serve the Minnesota Power System loads and revenues for Great River Energy's use of the Minnesota Power system facilities to serve their respective loads in the Minnesota Power pricing zone. Each company in the zone may have larger or smaller revenues and expenses depending on their load and investment of transmission assets within the zone as a share of the overall load and investment of transmission assets within the zone. The JPZ Agreement includes a maximum annual payment cap of $3.2 million Total Company ($2.1 million MN Jurisdictional). The MN Jurisdictional amounts for these years were $2.2 million (2023), $0.7 million (2024), and $2.1 million (2025). The 2027 test year includes a payment cap of $2.5 million Total Company ($2.1 million MN Jurisdictional) to Great River Energy which is consistent with what Minnesota Power has budgeted in other years.
- Ancillary Service Costs – The Minnesota Power system currently incurs costs and receives revenue under the MISO Tariff for Scheduling, System Control and Dispatch Service (Schedule 1) for ancillary services needed by the Minnesota Power system to serve native load within the Minnesota Power pricing zone; and
- MISO Administrative Charges – MISO charges its transmission service customers, such as the Minnesota Power System, its Schedule 10 and Schedule

35 administrative charge to recover the costs of administering its Tariff and providing other transmission functions.

Q. How are the wholesale transmission revenues kept accurate and current?

A. Minnesota Power provides updated third-party transmission revenue requirements to MISO and builds the Wholesale Transmission Revenue budget based on these updated revenues and expected loads. Revenue requirements for Schedules 1, 7, 8, 9, 26, 26A, and 45 of the MISO Tariff are updated every year through Schedule 1 and Attachments O, GG, MM, N-1 and ZZ filings. These updates are required by the MISO Tariff and coordinated with MISO Tariff Administration staff to reflect current year projected costs and the true-up of prior period costs and loads.

Q. Has Minnesota Power reasonably and prudently developed its third-party transmission revenues and expenses budget for the 2027 test year?

A. Yes. The Company has taken into account all the details available, known trends, and system expectations to carefully, thoughtfully, and reasonably develop the third-party transmission revenues and expenses for the 2027 test year.

Through the continued budgeting and monitoring of O&M, the compliance of NERC Reliability Standards, and managing and monitoring the interconnectivity of the transmission system and the revenue and expense associated with that interconnectivity, the Company continues to focus on the efficient maintenance of the transmission system.

V. RELIABILITY AND SYSTEM PERFORMANCE

Q. What is Minnesota Power's approach to transmission system reliability?

A. As outlined in the Transmission Capital Investments and Projects section of my Direct Testimony (Section III), Minnesota Power takes a long-range approach to the identification of long-term solutions to ensure the ongoing reliability of the transmission system. However, rapid or unexpected changes will occur in operations that require near-term and real-time solutions in order to resolve and maintain reliability. Minnesota

Power works closely both internally with multiple groups across the organization and externally with transmission interconnected neighbors as well as with the MISO to monitor and coordinate system conditions on a real-time basis as well as operating and planning time horizons. Affordability is factored into capital investments while keeping reliability in mind in several ways: 1.) Single circuit 115 kV and 230 kV lines are typically designed and built using guyed wood structures which are more affordable than self-supporting steel. 2.) A loading criterion is thoughtfully considered and selected for each project to balance affordability and reliability for any given line. 3.) When analyzing reject poles, cost of access, future rebuild status of the line, and age/condition of other poles on a given structure are considered for C-truss installation, single pole replacement, or entire structure replacement. The rationale is that if the pole is a restorable reject and there is a rebuild project in the 10-year plan, the Company will install a C-truss to restore the ground line of the pole and forego replacement until a larger project where access will be more efficient and cost effective. Similarly, if one pole on a two-pole H-frame structure requires replacement, access and age/condition of the other pole is considered to minimize future mobilization and construction costs when crews and equipment are already on site. 4.) Creating a reliable and cost-effective design is always a top priority, and designs are carefully thought out, planned, and reviewed to ensure designs are not overly conservative.

Q. What trends has Minnesota Power seen related to transmission system reliability?

A. MISO notes in its 2026 Reliability Imperative that the bulk electric system has shifted from predictable load and generation patterns towards one that is shaped by renewable generation variability, load fluctuations, and weather events. This is Minnesota Power's experience as well. Regular system congestion occurrences or reliability challenges of the past have increased with this shift in generation resources, which has caused Minnesota Power to reevaluate mitigation options and effectiveness. Also, as the Company works to construct the transmission system of the future, outages of existing transmission lines will be necessary. These outages, that are often aligned with corridors identified for increased transfer capabilities, will result in decreased transfer capabilities in the short term. Careful staging, study work, and coordination will be required to

minimize impact on reliability, all while limiting effects on timelines to put new projects into service.

Related to these trends is the desire by entities most directly impacted by congestion or system limitations to advocate for solutions that are quick, economic, and completely effective. These drivers are often mutually exclusive and even when implemented, can instead simply shift the problem to a different area of the transmission system. Also, simultaneous reliability issues in close proximity can result in stacking of mitigation solutions, which will complicate the ability to assess overall effectiveness of the solutions should a transmission line contingency or other rapid system change occur. Effective and current operating procedures along with accurate monitoring tools can be used to limit the risks while maximizing the use of the transmission system, but reliability should remain the ultimate priority.

Q. Please provide an example of this transmission reliability trend.

A. An example of this trend is the result of FERC Order No. 881 which requires transmission providers to utilize weather-adjusted capacity limits instead of static seasonal assumptions. The intent of the order is that by calculating line ratings using actual ambient temperature, greater capacity levels will be available from the existing transmission system. This should result in reduced congestion, greater access to the grid for generation of all types, and lower costs to serve load. It is also possible that challenging operating periods driven by very hot summer temperatures could result in ambient facility ratings being lower than previous static seasonal ratings.

Q. What is Minnesota Power doing to maintain transmission system reliability?

A. Minnesota Power transmission system reliability is addressed and maintained across multiple time horizons. As noted previously, long-range planning, usually looking into the future five years and over, is focused on capital projects of various scope and scale. These projects can range from HVDC Modernization or MISO LRTP projects to more localized system upgrades. These types of solutions generally require extensive study and development to determine the optimal project. When they are put into service, they

usually provide very large increases in reliability, transfer capability and congestion relief. Ideally, these additional margins gained should take many years to fully utilize.

In the intermediate time range of months to years into the future, the Company prioritizes solutions that can be implemented to maintain reliability in the same horizon. These types of solutions typically involve minor physical changes to assets in order to increase capabilities, reduce congestion, and limit impacts on reliability. Replacing a single series element that comprises a transmission line facility can sometimes result in enough improvement to capacity to avoid a more expensive complete facility replacement. Examples include targeted transmission pole replacements to increase line clearances or replacing a line disconnect with one rated for higher current ratings. By delaying a larger facility upgrade in the near term, certainty can be gained on the need and design of a long-term solution.

Q. Does Minnesota Power work with MISO to monitor transmission system reliability?

A. Yes. To maintain reliability in real-time operations, Minnesota Power works closely with MISO to monitor and evaluate the bulk electric system. Because of the proactive approach to planning a reliable transmission system, under normal conditions the level of reliability is incredibly high. Only during abnormal times usually caused by multiple system outages and/or stressed conditions from weather events does maintaining the same high level of reliability become challenged. Through careful preplanning of known system changes such as planned transmission line or generator outages, optimal periods can be identified that result in the least adverse impact. Coordinating the maintenance outage of a transmission line that provides a critical path to a large industrial customer or generation facility with an annual outage of those facilities is a simple but effective solution to limit reliability and congestion impacts. The Company has numerous operating guides and procedures developed based on studies that guide proactive responses to changing conditions. Examples include reconfiguring the transmission system by opening specific circuit breakers that will automatically adjust conditions should a critical contingency occur. The Company also has a long history of

adjusting transmission line ratings on a targeted basis based on ambient temperature, similar to the process that will be required by FERC Order 881. By intentionally scheduling critical transmission outages during periods of the year when additional capacity is likely available, reliability impacts can be minimized.

Recently, the Company implemented a more advanced version of Ambient Adjusted Ratings ("AAR"), called Dynamic Line Ratings ("DLR"), which is a type of Grid Enhancing Technology ("GET"). This technology directly monitors environmental conditions that would otherwise require the use of conservative assumptions in calculations that ultimately determine the amount of transfer capability that a transmission line conductor can have. Fewer assumptions mean a more accurate and potentially higher rated value resulting in better utilization of the existing transmission system. Minnesota Power has deployed this technology in 2026 to six transmission lines across the Company's service territory that have either experienced congestion in the past or have a heightened likelihood to experience congestion in the future. This potential is because all six of the selected lines are parallel to corridors of existing facilities that may be utilized for development of MISO LRTP projects. During outages of these parallel facilities for construction, loading levels on the DLR monitored lines will be increased thereby increasing the chance of congestion. Developing a solid understanding of the benefits or limitations of DLR in advance of future outages will enable reliability to be maintained through what is expected to be challenging operating periods. Three of these facilities were also identified in Appendix B of the 2025 Biennial Report, titled Grid Enhancing Technologies Study Report (Constraints with Solution Proposals). As noted in the study report, additional equipment will need to also be upgraded or replaced in order to fully utilize the capability of the line conductor.

Not enough operational history has been recorded to make a conclusive determination on effectiveness, but generally the technology has shown that additional transfer capability is available. Even short periods of transmission system congestion can result in substantial MISO market cost to redispatch resources, so having this DLR tool

available if needed is expected to result in savings to Minnesota Power and the broader MISO system.

Q. How has the Company improved the maintenance of transmission lines?

A. Maintenance programs for transmission lines have been improved through the following:

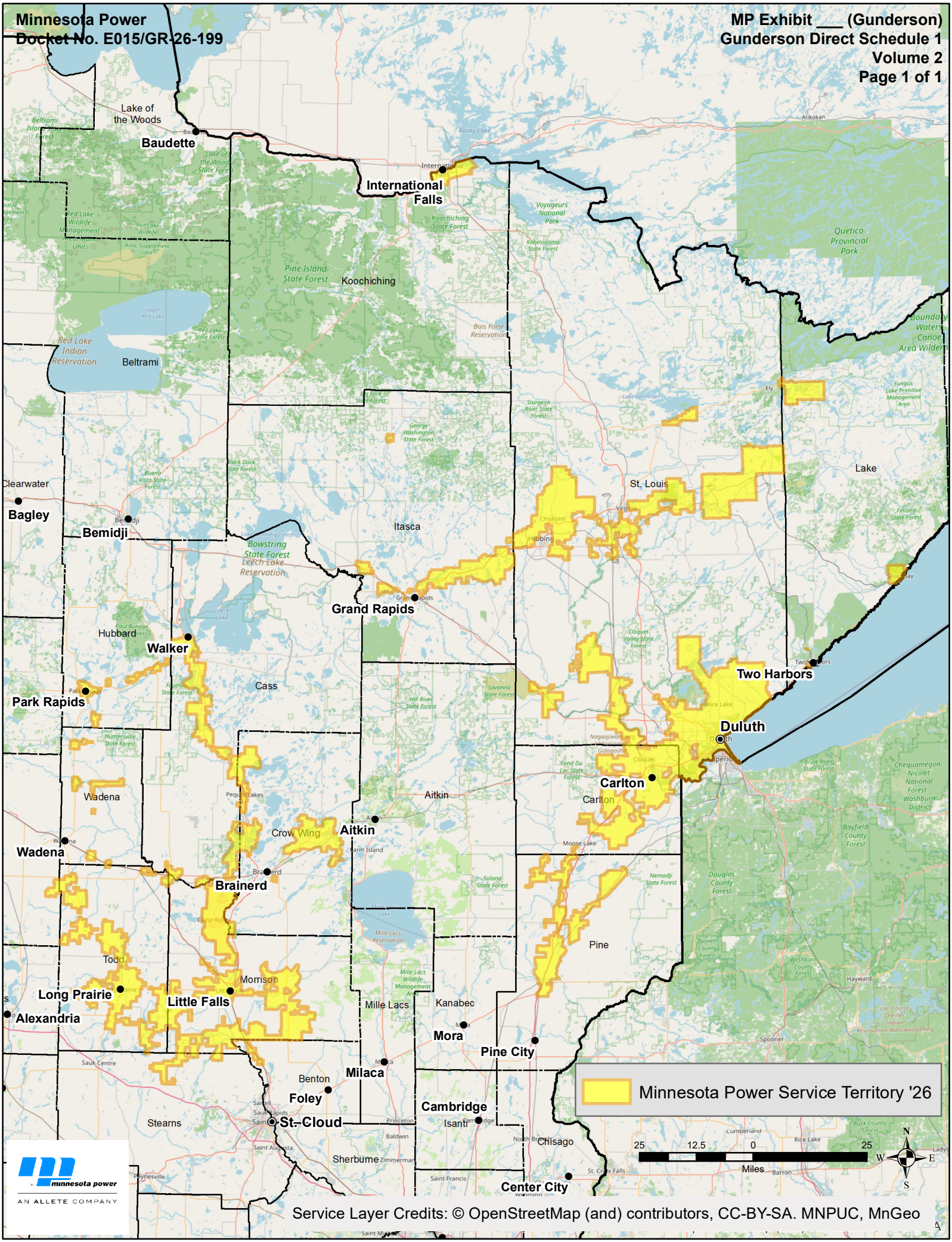
- Ground Line Inspection-Wood poles are inspected at groundline for rot, insects, and other damage on an eight-year cycle by a contractor.
- Aerial Helicopter Line Patrols-Lines that are 500 kV and over and below 250 kV HVDC Lines are inspected quarterly. 115 kV and 230 kV lines are inspected biannually.
- Ground Line Replacements-Following the groundline inspection, poles and structures are replaced to address defects found. This is a new item in the budget that was added to explicitly address issues found during groundline inspections to keep lines compliant with the National Electric Safety Code (NESC) as well as mitigate wildfire risk.
- When aerial inspections or groundline inspections find the need for replacements, capital Asset Renewal Program budgets and strategy around schedule are determined; storm related issues are addressed as needed.
- The frequency of cleaning insulators has been increased at certain high contamination sites across the system.

The Company has and continues to focus on ensuring that Minnesota Power's Tranmission System is available to provide safe and reliable service to its customers.

VI. CONCLUSION

Q. Does this complete your Direct Testimony?

A. Yes.

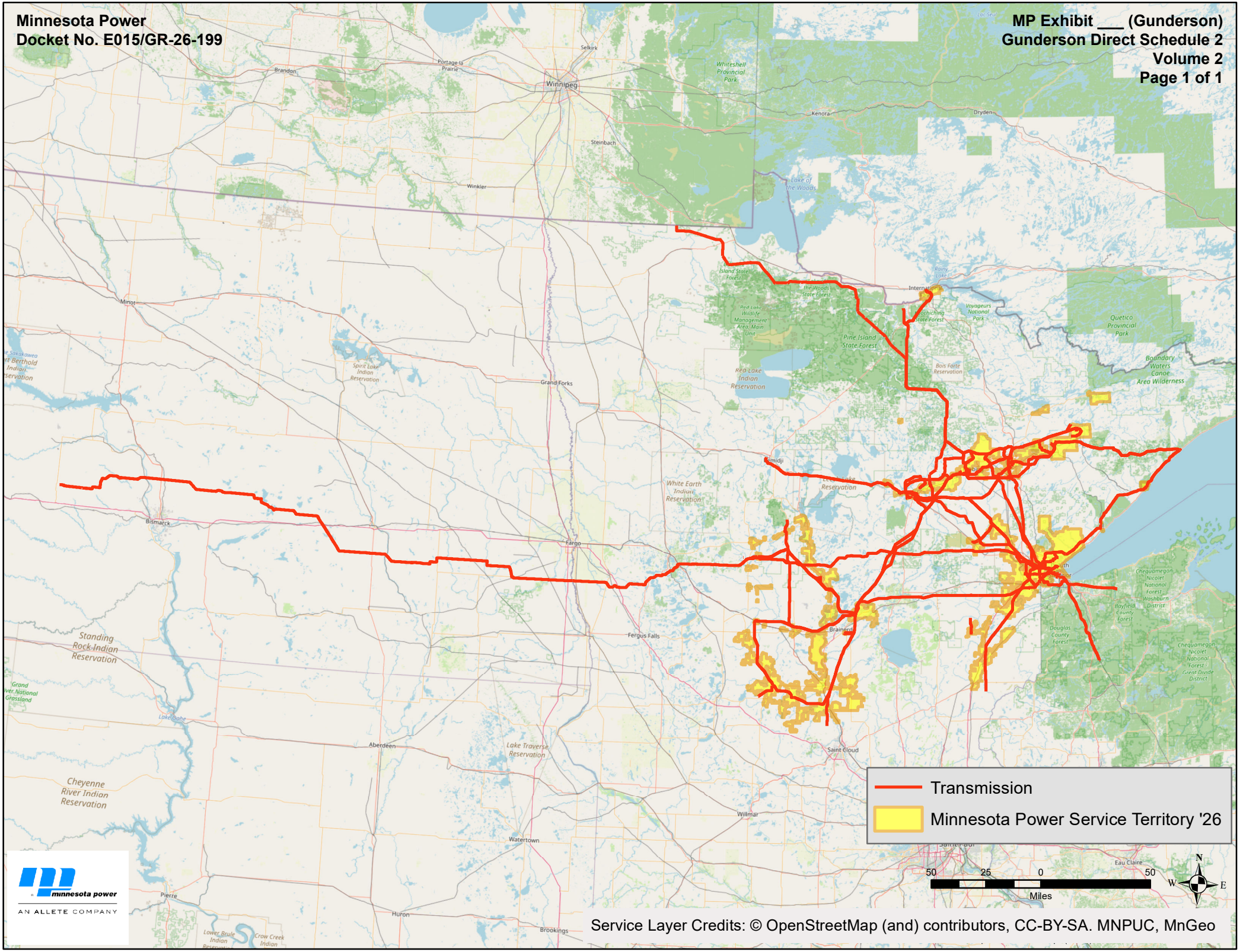


minnesota power
AN ALLETE COMPANY

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Minnesota Power
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MP Exhibit ___ (Gunderson)
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MP Exhibit ___ (Gunderson)
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LEGEND
- Proposed Route
- Project Substation
- Non-Project Substation
- Relocated Distribution
- Project 115 kV Transmission Line(s) (Single Circuit)
- Project 115 kV Transmission Line (Double Circuit)
- Project 230 kV Transmission Line (Single Circuit)
- Removed Transmission Line (Realigned)
- Thermal Upgrades
- New Underground Fiber
- Existing Transmission Line
- Existing Pipeline
- Park
- Cemetery
- Waterbody
- Public Water Watercourse
- Airport
- City Boundary

NOTE: ONLY EXISTING LINE LABELS ARE PROVIDED FOR REFERENCE. FOR FURTHER DEFINITION ON FINAL LINE CONFIGURATIONS AND DESIGNATIONS, SEE MAP 2-4 PROPOSED SYSTEM OVERVIEW OR APPENDIX K-3

0 Feet 4,000

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PROPOSED 115 KV ROUTE
DULUTH LOOP RELIABILITY PROJECT

minnesota power

Minnesota Power System Third-Party Transmission Revenue and Expenses
(Total Company)

	2023 - Actuals			2024 - Actuals			2025 - Actuals			2026 Projected Fiscal Year			2027 Proposed Test Year		
	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin
Base Rates	**$ 66.00**	**$ 47.50**	**$ 18.50**	**$ 55.30**	**$ 26.50**	**$ 28.80**	**$ 61.30**	**$ 41.40**	**$ 19.90**	**$ 110.20**	**$ 88.60**	**$ 21.60**	**$ 92.20**	**$ 68.90**	**$ 23.30**
Admin Schedules	$ -	$ 2.30	$ (2.30)	$ -	$ 2.40	$ (2.40)	$ -	$ 2.90	$ (2.90)	$ -	$ 3.90	$ (3.90)	$ -	$ 4.10	$ (4.10)
Ancillary Services	$ 0.70	$ 0.60	$ 0.10	$ 0.50	$ 0.70	$ (0.20)	$ 0.40	$ 1.10	$ (0.70)	$ 0.50	$ 0.20	$ 0.30	$ 0.30	$ 0.20	$ 0.10
Base Transmission	$ 31.20	$ 32.40	$ (1.20)	$ 24.80	$ 16.00	$ 8.80	$ 33.70	$ 27.50	$ 6.20	$ 30.50	$ 25.70	$ 4.80	$ 19.10	$ 14.40	$ 4.70
GRE Joint Pricing Zone	$ -	$ 2.70	$ (2.70)	$ -	$ 0.80	$ (0.80)	$ -	$ 2.50	$ (2.50)	$ -	$ 3.10	$ (3.10)	$ -	$ 2.50	$ (2.50)
Manitoba Must Take Fee	$ 20.10	$ -	$ 20.10	$ 19.30	$ -	$ 19.30	$ 18.60	$ -	$ 18.60	$ 17.90	$ -	$ 17.90	$ 17.30	$ -	$ 17.30
MISO / FERC Refund Accrual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MISO Transmission Rates True-up	$ 1.50	$ -	$ 1.50	$ 1.10	$ -	$ 1.10	$ (2.10)	$ -	$ (2.10)	$ 3.30	$ -	$ 3.30	$ 5.80	$ -	$ 5.80
NERC	$ 10.10	$ 9.50	$ 0.60	$ 7.70	$ 6.60	$ 1.10	$ 8.70	$ 7.40	$ 1.30	$ 5.70	$ 5.60	$ 0.10	$ 6.20	$ 6.80	$ (0.60)
Wheeling	$ 2.40	$ -	$ 2.40	$ 1.90	$ -	$ 1.90	$ 2.00	$ -	$ 2.00	$ 2.20	$ -	$ 2.20	$ 2.60	$ -	$ 2.60
Attachment N1- HVDC Modernization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50.10	$ 50.10	$ -	$ 40.90	$ 40.90	$ -
Direct Customer	**$ 3.40**	**$ 1.50**	**$ 1.90**	**$ 4.40**	**$ 1.70**	**$ 2.70**	**$ 4.30**	**$ 2.00**	**$ 2.30**	**$ 3.00**	**$ 0.70**	**$ 2.30**	**$ 2.30**	**$ -**	**$ 2.30**
Customer	$ 1.50	$ 1.50	$ -	$ 1.70	$ 1.70	$ -	$ 2.00	$ 2.00	$ -	$ 0.70	$ 0.70	$ -	$ -	$ -	$ -
GRE Distribution	$ 1.90	$ -	$ 1.90	$ 2.70	$ -	$ 2.70	$ 2.30	$ -	$ 2.30	$ 2.30	$ -	$ 2.30	$ 2.30	$ -	$ 2.30
Transmission Recovery- RECB	**$ 22.00**	**$ 38.50**	**$ (16.50)**	**$ 19.30**	**$ 36.30**	**$ (17.00)**	**$ 24.70**	**$ 33.80**	**$ (9.10)**	**$ 39.30**	**$ 34.30**	**$ 5.00**	**$ 55.60**	**$ 36.00**	**$ 19.60**
Cost Shared Projects	$ 22.00	$ 38.50	$ (16.50)	$ 19.30	$ 36.30	$ (17.00)	$ 24.70	$ 33.80	$ (9.10)	$ 39.30	$ 34.30	$ 5.00	$ 55.60	$ 36.00	$ 19.60
Total	**$ 91.40**	**$ 87.50**	**$ 3.90**	**$ 79.00**	**$ 64.50**	**$ 14.50**	**$ 90.30**	**$ 77.20**	**$ 13.10**	**$ 152.50**	**$ 123.60**	**$ 28.90**	**$ 150.10**	**$ 104.90**	**$ 45.20**

Minnesota Power System Third-Party Transmission Revenue and Expenses
(Minnesota Jurisdictional)[1]

	2023 - Actuals			2024 - Actuals			2025 - Actuals			2026 Projected Fiscal Year			2027 Proposed Test Year		
	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin
Base Rates	**$ 54.20**	**$ 39.00**	**$ 15.20**	**$ 45.90**	**$ 22.10**	**$ 23.80**	**$ 50.30**	**$ 34.10**	**$ 16.20**	**$ 90.70**	**$ 73.10**	**$ 17.60**	**$ 71.10**	**$ 53.20**	**$ 17.90**
Admin Schedules	$ -	$ 1.90	$ (1.90)	$ -	$ 2.00	$ (2.00)	$ -	$ 2.40	$ (2.40)	$ -	$ 3.20	$ (3.20)	$ -	$ 3.20	$ (3.20)
Ancillary Services	$ 0.60	$ 0.50	$ 0.10	$ 0.40	$ 0.60	$ (0.20)	$ 0.30	$ 0.90	$ (0.60)	$ 0.40	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ -
Base Transmission	$ 25.60	$ 26.60	$ (1.00)	$ 20.60	$ 13.30	$ 7.30	$ 27.70	$ 22.60	$ 5.10	$ 25.10	$ 21.20	$ 3.90	$ 14.70	$ 11.10	$ 3.60
GRE Joint Pricing Zone	$ -	$ 2.20	$ (2.20)	$ -	$ 0.70	$ (0.70)	$ -	$ 2.10	$ (2.10)	$ -	$ 2.60	$ (2.60)	$ -	$ 1.90	$ (1.90)
Manitoba Must Take Fee	$ 16.50	$ -	$ 16.50	$ 16.00	$ -	$ 16.00	$ 15.30	$ -	$ 15.30	$ 14.70	$ -	$ 14.70	$ 13.30	$ -	$ 13.30
MISO / FERC Refund Accrual	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MISO Transmission Rates True-up	$ 1.20	$ -	$ 1.20	$ 0.90	$ -	$ 0.90	$ (1.70)	$ -	$ (1.70)	$ 2.70	$ -	$ 2.70	$ 4.50	$ -	$ 4.50
NREAC	$ 8.30	$ 7.80	$ 0.50	$ 6.40	$ 5.50	$ 0.90	$ 7.10	$ 6.10	$ 1.00	$ 4.70	$ 4.60	$ 0.10	$ 4.80	$ 5.20	$ (0.40)
Wheeling	$ 2.00	$ -	$ 2.00	$ 1.60	$ -	$ 1.60	$ 1.60	$ -	$ 1.60	$ 1.80	$ -	$ 1.80	$ 2.00	$ -	$ 2.00
Attachment N1- HVDC Modernization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41.30	$ 41.30	$ -	$ 31.60	$ 31.60	$ -
Direct Customer	**$ 2.80**	**$ 1.20**	**$ 1.60**	**$ 3.60**	**$ 1.40**	**$ 2.20**	**$ 3.50**	**$ 1.60**	**$ 1.90**	**$ 2.50**	**$ 0.60**	**$ 1.90**	**$ 1.80**	**$ -**	**$ 1.80**
Customer	$ 1.20	$ 1.20	$ -	$ 1.40	$ 1.40	$ -	$ 1.60	$ 1.60	$ -	$ 0.60	$ 0.60	$ -	$ -	$ -	$ -
GRE Distribution	$ 1.60	$ -	$ 1.60	$ 2.20	$ -	$ 2.20	$ 1.90	$ -	$ 1.90	$ 1.90	$ -	$ 1.90	$ 1.80	$ -	$ 1.80
Transmission Recovery- RECB	**$ 18.10**	**$ 31.60**	**$ (13.50)**	**$ 16.00**	**$ 30.10**	**$ (14.10)**	**$ 20.30**	**$ 27.80**	**$ (7.50)**	**$ 32.40**	**$ 28.30**	**$ 4.10**	**$ 42.90**	**$ 27.80**	**$ 15.10**
Cost Shared Projects	$ 18.10	$ 31.60	$ (13.50)	$ 16.00	$ 30.10	$ (14.10)	$ 20.30	$ 27.80	$ (7.50)	$ 32.40	$ 28.30	$ 4.10	$ 42.90	$ 27.80	$ 15.10
Total	$ 75.10	$ 71.80	$ 3.30	$ 65.50	$ 53.60	$ 11.90	$ 74.10	$ 63.50	$ 10.60	$ 125.60	$ 102.00	$ 23.60	$ 115.80	$ 81.00	$ 34.80

[1] Please note that the application of allocators in Schedule 4 to determine Minnesota Jurisdictional amounts have been simplified from the application of allocators in the Class Cost of Service Study ("CCOSS"). Therefore, total project costs at the Minnesota Jurisdictional level may not exactly total the amounts from the actual CCOSS.