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-21-335

Exhibit ________

TRANSMISSION AND DISTRIBUTION

November 1, 2021

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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., doing business as Minnesota Power ("Minnesota Power" or the "Company") as the Vice President of Transmission and Distribution.

Q. Please summarize your qualifications and experience.

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, the Advanced Metering Infrastructure ("AMI") System technology and implementation, and managing work for technicians that 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. These areas include approximately 400 employees, with nearly 200 of those employees as members of International Brotherhood of Electric Workers Local 31.

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to provide background on the Company's power delivery systems. I discuss the capital investments the Company has made since our last rate case in Docket No. E015/GR-16-664 (the "2016 Rate Case") and the operations and maintenance ("O&M") necessary to continue to provide efficient and reliable electricity to Minnesota Power customers in a cost-efficient manner. I will provide information to support the Company's reasonable, necessary, and prudent investments in local and regional capital projects and ongoing maintenance of our power delivery systems. I am also providing 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 power delivery system reliability, customer relations, and business efficiency related to this critical Company function.

Q. How is your testimony organized?

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

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

Section IV describes the O&M processes and costs for transmission and distribution. This section also explains third-party transmission revenues and expenses, as well as the Company's vegetation management program and costs, regulatory compliance oversight for transmission system reliability, service center updates, and purchasing and procurement initiatives.

Finally, in Section V, I discuss the Company's system reliability, customer relations and items related to the customer experience, and technology updates as they relate to the modernization of systems used to complete our work.

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 – Service Territory Map;
- MP Exhibit ___ (Gunderson), Direct Schedule 2 – North Shore Loop;
- MP Exhibit ___ (Gunderson), Direct Schedule 3 – Grand Rapids Area; and
- MP Exhibit ___ (Gunderson), Direct Schedule 4 – Third-Party Transmission Revenue and Expense.

II. TRANSMISSION AND DISTRIBUTION WORK AREAS

Q. Please explain the role of Minnesota Power's Transmission and Distribution Department.

A. Minnesota Power's Transmission and Distribution Department is responsible for the construction, management, and O&M of Minnesota Power's power delivery systems. This 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 and, ultimately, to our customers. The department is also responsible for the residential and small commercial customer data from the meter to billing system. The Support Services area includes Fleet, Purchasing, Security, Facility Management, and Engineering Services. Support Services generally provides centralized management of key activities, as well as strategic sourcing and other supply chain efficiencies. These services are critical to operations, and this area works closely with leadership in the implementation of efficiency improvements and cost containment efforts.

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

A. Minnesota Power's transmission system is, generally, voltages between 115 kilovolts ("kV") up to 500 kV.[1] The Company's transmission system is located primarily in Minnesota and portions of North Dakota. These transmission facilities deliver power from various generating resources, including wind, solar, coal, biomass, natural gas, and hydro. Minnesota Power's transmission facilities serve local loads across nearly 26,000 square miles of central and northeastern Minnesota and are critical to supporting the larger regional transmission system reliability.

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

A. The Company's distribution system is located in northeastern Minnesota. Certain areas within these general borders receive distribution service from municipalities or rural electric cooperatives. As such, Minnesota Power routinely coordinates closely with these entities to ensure efficient transmission delivery to distribution systems. A map of Minnesota Power's distribution service territory is provided with my Direct Testimony as MP Exhibit ___ (Gunderson), Direct Schedule 1.

III. CAPITAL INVESTMENTS AND PROJECTS

A. Capital Investments Budget Overview

Q. How is the capital budget developed?

A. Minnesota Power maintains a long-range capital investment plan based on identified needs and priorities. As discussed later in my Direct Testimony, capital projects are placed in the long-range plan based on their value and priority. Analyzing and prioritizing these projects is the first step in determining their necessity and timing, which informs the annual capital budget. Starting with this long-range plan, Minnesota Power employs a zero-based budgeting process, explained in more detail in the Direct

[1] Certain customers may receive energy at voltages of 115 kV, delivered directly to their facilities. These customers are generally large energy users that require transmission connections.

Testimony of Company witness Joshua G. Rostollan. The capital budget undergoes a bottom-up, multi-level gated process to affirm that the capital projects are required within a specific year for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet work areas. Each of these areas maintain individual long-range plans based on identified needs and priorities that are used to build each year's capital budgets.

During the first phase of the annual capital budget process, each area reviews their long-range plan in conjunction with expected spending and necessary timing and identifies the slate of projects to move to the next phase. The second phase involves cross-functional organizational review. Leadership and subject matter experts from Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet 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 in October.

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 advice to senior management for the portfolio of capital projects led by the Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet 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, 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 actuals 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. A monthly review of year-to-date actual performance with year-to-date and year-end forecasts may identify a project change. Examples of project changes include:

- Project estimate has been refined from a planning estimate to a detailed estimate;
- Previously identified risks cease to exist, and any funds held for that risk are removed from the project's forecast;
- Budgeted schedule is no longer viable and a portion of the project must be advanced or delayed to a different calendar year due to extended procurement times or inability to commit to delivery times by manufacturers based on current production constraints and delivery delays;
- Change is identified during the project, possibly related to scope addition or reduction, change in required resources, or pricing of contract(s). The Company anticipates an increase in pricing of commodities and construction labor due in part to overall increased capital investment (demand) across the utility industry; and
- Unplanned work arises that is required to be completed or is strategic in nature. This may include road relocations required as a result of local government decisions or meeting customer electric service requirements.

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 monthly reports of 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. The Company is currently experiencing unprecedented uncertainty around capital projects relating to risks of a changing and challenged supply chain. Vendors are challenging Company contract terms and conditions that were previously widely accepted, lengthening the procurement cycle, as those terms are reconciled. At the same time, the Company is facing increased challenges in securing production timeslots for major materials due to the following: 1) longer than historical manufacturing lead times; 2) manufacturing companies not all being at full, pre-pandemic, production capacity; and 3) large natural disasters that have put additional pressure on common commodity items, compounding the previously mentioned challenges. Minnesota Power is encountering increasing rates for major materials and contract labor due to this supply and demand tension and overall inflation speculation. The Company assesses these factors that could increase project costs significantly compared to historical values.

The risks identified above are partially attributable to the overall economic challenges presented by the COVID-19 pandemic. In addition to challenged procurement schedules, the Company is experiencing difficulty in coordinating construction outages within available outage windows for larger and more complex capital projects due to the limitations in availability of labor, which could delay overall project completion and will increase costs due to multiple mobilizations and demobilizations.

In this ever-changing landscape, Minnesota Power continues to work diligently to identify ways it can mitigate some of these risks for the benefit of customers. Specifically, the Company is acting to mitigate some of these risks through the following methods: increased monitoring of inventory levels for major and commonly-procured materials; utilizing vendor alliances to assist in monitoring supply change impacts and proactively identifying alternate material and backup suppliers; and bulk ordering earlier in the process to secure production timeslots.

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

A. Minnesota Power's portfolio of capital projects is reviewed on a monthly basis. 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 and resource and customer commitments. Proposed changes to the portfolio of projects are reviewed and approved by the PRB, which is expected to manage the capital additions to the approved capital budget and which manages the Company's resources efficiently.

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 the rate case.

A. Maintaining some flexibility to replace projects within a test year is in the best interest of our customers for several reasons. While the Company identifies the portfolio of projects for the coming year, variations to that portfolio may be necessary as the year progresses to respond to changing circumstances and ensure the safe and reliable transmission and delivery of electricity to our customers. The Company actively manages its capital portfolio to ensure the highest priority projects are being addressed as they arise and that the Company is able to balance the financial aspects of the portfolio as well. As time progresses, higher priority projects may be identified, necessitating adjustments to the capital portfolio while still balancing the overall capital budget and resource requirements. The Company must have the ability to leverage capital and other resources as necessary when conditions require changes in our capital infrastructure investment.

Q. Please explain how you would like the Commission to consider this issue.

A. The Company has identified and budgeted for certain capital projects to be placed in service in the 2022 test year. Because Minnesota Power must provide safe, reliable, and cost-efficient energy to our customers, shifting in-service dates of certain projects may be necessary to meet changing needs.

The Commission has previously allowed such flexibility in shifting projects, recognizing that the utility industry is a dynamic business and priorities change.[2] 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. In fact, the Commission has found sufficient time where such substitution was included in an information request response and detailed in Rebuttal testimony.

Therefore, the Company will provide updates on 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.

Q. Will all of the projects included in the 2022 test year be placed into service during 2022?

A. At this time, the Company is on track to place all capital projects identified in the 2022 test year budget in service in 2022. 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 2022 — although the Company manages such circumstances to ensure the overall portfolio remains balanced.

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[2] *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); *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).

Q. What has the capital investment looked like from 2019 through 2022?

A. Table 1 provides the Company's regulated capital plant additions for 2019 actuals, 2020 actuals, 2021 projected year, and 2022 test year for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, and Fleet work areas. Table 1 is provided at the Total Company level. Capital plant additions at the Minnesota Jurisdictional level are provided in Table 2.[3]

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

Capital Plant Additions (including Contra) -- Total Company	2019	2020	2021	2022
	Actuals	Actuals	Projected Year	Test Year
Transmission*	$31.5	$26.8	$16.8	$29.3
Asset Management	$6.0	$6.5	$9.9	$8.4
Baseline Reliability	$2.6	$2.5	$4.8	$1.1
Externally Driven	$1.3	$3.3	$0.8	$0.5
Externally Driven/Credit	($8.1)	-	-	-
Strategic/Grand Rapids Area	$8.6	$0.8	-	-
Strategic/North Shore Loop	$21.2	$13.7	$1.3	$19.3
Distribution*	$25.7	$27.1	$37.7	$35.8
Age Related & Asset Renewal	$12.4	$8.4	$13.0	$22.2
Capacity	$0.1	$0.4	$0.7	$0.7
Distribution Other	-	$2.9	$2.7	$2.2
Government Requirements	$1.2	$3.6	$1.5	$0.8
Grid Modernization & Pilot Projects	$0.5	-	$1.0	$1.0
Metering	$4.2	$7.1	$10.0	$1.9
New Customer_New Revenue	$5.3	$2.5	$4.5	$4.2
Reliability & Power Quality	$2.0	$2.2	$4.4	$2.8
Cyber Technology Services	$3.4	$7.1	$21.5	$18.1
Facility Management	$3.7	$8.5	$2.5	$3.7
Fleet	$3.3	$5.5	$6.0	$4.3
Security	$0.8	$0.7	$0.6	$0.2
T&D Subtotal, Excluding Riders	**$68.5**	**$75.6**	**$85.2**	**$91.3**

Amounts in millions.
Amounts may not total due to rounding.
**Amounts may include Intangible & General Plant additions.*

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

Table 2. Capital Plant Additions (Including Contra AFUDC)
(MN Jurisdictional)

Capital Plant Additions (including Contra) -- MN Jurisdictional	2019	2020	2021	2022
	Actuals	Actuals	Projected Year	Test Year
Transmission*	$26.8	$22.2	$13.9	$24.0
Asset Management	$5.1	$5.4	$8.2	$6.9
Baseline Reliability	$2.2	$2.1	$3.9	$0.9
Externally Driven	$1.2	$2.7	$0.7	$0.4
Externally Driven/Credit	($7.1)	-	-	-
Strategic/Grand Rapids Area	$7.3	$0.7	-	-
Strategic/North Shore Loop	$18.1	$11.4	$1.2	$15.7
Distribution*	$25.0	$26.5	$37.8	$35.0
Age Related & Asset Renewal	$11.9	$7.9	$13.2	$21.4
Capacity	$0.1	$0.4	$0.7	$0.7
Distribution Other	($0.1)	$2.9	$2.6	$2.2
Government Requirements	$1.2	$3.6	$1.5	$0.8
Grid Modernization & Pilot Projects	$0.5	-	$1.0	$1.0
Metering	$4.2	$7.0	$9.9	$1.9
New Customer_New Revenue	$5.2	$2.5	$4.5	$4.2
Reliability & Power Quality	$1.9	$2.2	$4.4	$2.8
Cyber Technology Services	$3.0	$6.2	$19.0	$16.1
Facility Management	$3.3	$7.5	$2.2	$3.3
Fleet	$2.9	$4.9	$5.3	$3.8
Security	$0.7	$0.6	$0.6	$0.1
T&D Subtotal, Excluding Riders	**$61.7**	**$67.9**	**$78.9**	**$82.2**

Amounts in millions.
Amounts may not total due to rounding.
**Amounts may include Intangible & General Plant additions.*

Q. How are the Capital Additions in Table 1 summarized 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 and distribution 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 impacted 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. Some examples from the 2022 test year where we encounter these combinations of assets — which are discussed in greater detail later in my Direct Testimony — are the Forbes Tie Breaker Project, North Shore Transformer Addition, and Canosia Road 115 kV/34.5 kV Substation ("Canosia Road Substation 34.5 kV Expansion"). These projects add both Transmission and Distribution assets for which the Company budgets and identifies in the various classifications for purposes of providing the necessary financial supporting information to the Commission. Therefore, classifying capital additions for each of these projects, 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.

Q. How do the capital additions in the 2022 test year budget and the 2021 projected year in Table 1 compare to the Company's 2020 actuals?

A. The capital additions projected for the Transmission and Distribution and Support Services work areas for the 2022 test year and the 2021 projected year are $15.7 million Total Company ($14.3 million MN Jurisdictional) and $9.6 million total Company ($11.0 million MN Jurisdictional) greater than the capital additions in 2020, respectively.

Transmission capital additions in the 2022 test year are $2.5 million Total Company ($1.8 million MN Jurisdictional) greater than the capital additions in 2020, whereas and the capital additions in the 2021 projected year are $10.0 million Total Company ($8.3 million MN Jurisdictional) less than the capital additions in 2020. Transmission capital additions included in the 2022 test year are discussed further in Section III.B of my Direct Testimony.

Distribution capital additions in the 2022 test year and the 2021 projected year are $8.7 million Total Company ($8.5 million MN Jurisdictional) and $10.6 million Total Company ($11.3 million MN Jurisdictional) greater than the capital additions in 2020, respectively. Distribution capital additions included in the 2022 test year are discussed further in Section III.C of my Direct Testimony.

Cyber Technology Services capital additions in the 2022 test year and the 2021 projected year are $11.0 million Total Company ($9.9 million MN Jurisdictional) and $14.4 million Total Company ($12.8 million MN Jurisdictional) greater than the capital additions in 2020, respectively. Cyber Technology additions included in the 2022 test year are discussed further in Section V.C of my Direct Testimony.

B. <u>Transmission Capital Investments and Projects</u>

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. 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 for the Company by MISO. Through the annual MISO Transmission Expansion Planning ("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 of the system-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 wire 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 particular 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 Integrated Resource Plan ("IRP")[4] at the time, and then a petition requesting approval for implementation could move forward. If the non-wire resource option did not fit with the timing of the current IRP analysis, then it could be considered in the next IRP submittal or a separate petition. If the transmission system issue needed 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.

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.

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[4] The Company's most recent IRP was filed in February 2021 and is currently under review (Docket No. E015/RP-21-033).

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 stakeholders to identify, prioritize, and scope replacements or upgrades of high-priority, high-impact, or high-value assets. In recent years, previously unconnected asset renewal programs involving substation equipment have been integrated into a single substation modernization program designed to efficiently and holistically address all of the asset renewal and known long-term reliability needs at a site with one comprehensive project.

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.

Q. What are the main drivers for Externally-Driven Projects?

A. The main drivers for Externally-Driven Projects are the needs or requirements of external entities affecting the transmission system. 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 FERC open access transmission service rules.[5]

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[5] *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).

Q. How are Externally-Driven Projects identified?

A. Externally-Driven Projects are identified when requested by an external entity. To minimize the schedule and cost risks associated with external project requests, the Company has developed close coordination practices with major stakeholders such as its Large Power ("LP") customers and other utilities that serve the areas adjacent to Minnesota Power's transmission system.

Q. How does the Company coordinate with LP customers to ensure that Externally-Driven Projects are timely and appropriate?

A. The Company works closely with existing and potential future LP customers through regular two-way communications about upcoming needs and plans. The Company communicates its upcoming projects and required outages that may impact existing LP customer operations. Additionally, LP customers communicate their upcoming projects and infrastructure needs. The Company also participates in dialogue with potential future LP customers to identify the upgrades or investments that would be necessary to meet the potential customer's needs. Ongoing communication and customer relationships are maintained through the Company's dedicated Strategic Account professionals.

Q. How does the Company coordinate with other utilities to ensure that Externally-Driven Projects are timely and appropriate?

A. In addition to coordinating through the MISO MTEP process discussed above, the Company generally holds coordination meetings with neighboring utilities on an annual basis or as needed. Great River Energy is the second highest user of the Company's transmission system after Minnesota Power. Because of the increased level of coordination between the Company and Great River Energy, the Company has developed coordinated planning practices with Great River Energy to ensure timely and appropriate two-way project coordination between the two companies. Planning coordination with Great River Energy includes all projects proposed by either utility that will modify or interconnect to the transmission system in Minnesota Power's control area. The companies have agreed to specific requirements and timelines with regard to coordination of transmission planning studies, mutual agreement on long-term transmission solutions, project scoping review and approvals, review of major permit applications, and equitable delineation of ownership and investment in the transmission system. These efforts have been in place since 2016 and have greatly improved transmission planning coordination between the Company and Great River Energy.

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

A. Cost responsibility for Externally-Driven Projects varies depending on the situation. The Company ensures that all potential cost-sharing avenues are explored and utilized when working with an external entity. However, in some cases, the Company must bear the cost of the externally driven project. For 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.B.2 of my Direct Testimony.

Q. What are Strategic Projects?

A. Strategic Projects are transmission system upgrades related to larger Company initiatives like generation fleet transition or regional economic development. 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 wire 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. 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 studies. For Baseline Reliability Projects, the need date most often corresponds to the model-year in which it was first identified in the 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 Minnesota Biennial Transmission Projects Report.

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

A. Once a project has been identified through the evaluation processes discussed above, a project scope is defined by the Transmission and Distribution Planning Department. The project scope is intended to capture the information necessary to initiate a capital project. The project scope includes the following: general project description; purpose; permitting and schedule considerations; preliminary engineering and construction considerations; cost estimate; and cash flow. A scoping lead, typically from the Transmission and Distribution Planning Department, facilitates development of the project scope in coordination with various departments that will be involved in the project, including — but not limited to — Substation Engineering, Transmission Line Engineering, Relay and Maintenance Engineering, Meter Engineering, Communications Infrastructure, Distribution Engineering, Engineering Project Delivery, System Operations, Construction and Maintenance, the Land Department, and Environmental Permitting. Through this cross-functional coordination, preliminary indications of the schedule, required permits or approvals, route, site, layout, cost, cash flow, and construction plan considerations for a project are developed and incorporated into the project scope. The project scope is reviewed and refined by the internal group and coordinated with affected external entities until the scoping lead determines that it is complete and the project is ready to be handed off for PRB approval. Upon approval, it is assigned to a Project Manager.

Q. Please explain the capital budgeting process for each type of transmission project.

A. The capital budgeting process for transmission projects begins with Minnesota Power's long-range plan. Confirmation or update to the requested budget amounts for Transmission Asset Management Contingency Programs is requested from the subject matter experts for the assets. The required timing for Transmission Asset Management Asset Renewal Projects, Baseline Reliability Projects, Externally-Driven Projects, and Strategic Projects is confirmed, if necessary, and project scopes are developed for these projects — if not already complete. All projects potentially targeted for the budget year are evaluated based on value and priority.

The project value assessment includes: personnel and public safety; compliance and legal requirements; reliability; cost recovery; financial payback; efficiency and cost savings; and impact on Company strategy. The project prioritization assessment includes 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. Multi-year projects with previous phases completed or in progress include a work-in-progress component in the priority evaluation to ensure projects with substantive progress continue to be prioritized through completion. Transmission asset management contingency programs are generally given the highest priority to ensure that baseline utility needs are met. The remaining projects are assessed to ensure that the highest-priority projects are included in the capital budget. Lower-priority projects may be deferred, or project staging and project budget amounts may be refined, until a reasonable, prudent, and necessary final budget proposal is developed that will address Company needs and meet Company capital spending plans.

Q. What Baseline Reliability Projects are included in the 2022 test year?

A. There is one Baseline Reliability Project included in the test year — a capacity increase on the Hibbing – Virginia 115 kV Line ("25 Line") ("25 Line Upgrade Project").

Q. What is the 25 Line Upgrade Project and what will it address?

A. The 25 Line Upgrade Project involves targeted structure replacements to increase the thermal capability of the existing 25 Line, as well as targeted asset renewal components to address identified age and condition-related concerns related to the transmission line structures and hardware. Line loading in excess of the rated capacity following certain transmission outages ("post-contingent overloads") has been consistently identified on the 25 Line in the annual MISO MTEP assessment and Minnesota Power's internal studies for a number of years, primarily because it is one of the lowest-capacity 115 kV lines on the Company's system. The 25 Line Upgrade Project has been reported in the Minnesota Biennial Transmission Projects Report since 2019 under tracking number 2019-NE-N4.

Q. What Transmission Asset Management Projects are included in the 2022 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. Aside from these regular annual programs, specific larger Asset Renewal Projects in the test year include a rebuild and partial relocation of the existing Thomson – Fond Du Lac 115 kV No. 8 Line ("8 Line") ("8 Line Relocation Project") and repair of a failed HVDC converter transformer from the Square Butte HVDC Terminal ("Square Butte HVDC Transformer Rewind Project").

Q. What is the 8 Line Relocation Project and what will it address?

A. The 8 Line Relocation Project involves relocating a short segment of the existing 8 Line away from failing slopes above State Highway 210 near the Fond Du Lac Substation and rebuilding the line on the existing right-of-way from that point to the Thomson Substation. The project also includes transmission access improvements, a new 115 kV breaker and associated improvements at the Fond Du Lac Substation, and relatively minor improvements to the existing line entrance at the Thomson Substation. The project is necessary to mitigate the risk of structural failure on the failing slope section and to address age and condition concerns related to the remaining length of the line, which includes original components dating back to 1939. The 8 Line Relocation Project is part of a relatively recent effort by the Company to identify and prioritize holistic transmission line asset renewal projects, and it had not been identified at the time the 2019 Minnesota Biennial Transmission Projects Report was filed. The project will be included in the 2021 Minnesota Biennial Transmission Projects Report (Docket No. E999/M-21-111) which is anticipated to be filed by November 1, 2021.

Q. What is the Square Butte HVDC Transformer Rewind Project and why is it needed?

A. The Square Butte HVDC Transformer Rewind Project involves repair of a failed HVDC converter transformer originally located at the Center, North Dakota terminal of the HVDC line. The transformer will be disassembled and transported to a repair facility where it will be rebuilt, including rewinding of the internal transformer coils. Following rebuild, the transformer will be transported back to the Center HVDC terminal where it will be reassembled, filled with oil, tested, and placed back into service as a critical onsite spare. The project is necessary because the converter transformer failed in December 2020. Following this incident, the failed transformer was taken out of service, removed, and replaced with an onsite spare to restore the HVDC facility to service. Repair of the failed unit will provide for replacement of the spare unit that was installed in its place. This project will provide an important hedge against additional transformer failures that may occur as the HVDC facility and its components, many of which are original and date back to the 1970s, continue to age.

Q. What major Externally-Driven Projects are included in the 2022 test year?

A. There is only one Externally-Driven Project included for the test year — a Great River Energy project to expand the existing 230 kV bus at the Wing River Substation to a ring bus configuration ("Wing River Bus Expansion Project").

Q. What is the Wing River Bus Expansion Project and why is it needed?

A. Great River Energy's Wing River Bus Expansion Project involves converting the existing 230 kV portion of the Wing River Substation into a more reliable ring bus configuration. While this is primarily a Great River Energy project, the Company does have responsibility for replacing end-of-life Minnesota Power-owned metering and instrument transformers within the substation as part of the project. Great River Energy did not include the Wing River Bus Expansion in the 2019 Minnesota Biennial Transmission Projects Report. The Company anticipates that the project will be included in the 2021 Minnesota Biennial Transmission Projects Report.

Q. What Strategic Projects are included for the 2022 test year?

A. The Strategic Projects included in the 2022 test year are related to the transition of the Company's baseload coal generation fleet and resource mix. All projects are located in or adjacent to the North Shore Loop and are related to Company decisions to retire, idle, or convert generators to peaking operation in addition to the decision by Silver Bay Power Company — an external entity — to idle baseload generators at a cogeneration facility in Silver Bay following a contractual agreement with Minnesota Power.[6] While there are no projects in the test year related to the Company's decision to retire Boswell Energy Center ("BEC") Units 1 and 2, I have included a discussion of the impacts of this decision on the Grand Rapids area transmission system and the project that was completed prior to the test year to address these impacts.

[6] *In the Matter of a Petition by Minn. Power for Approval of an Amended and Restated Elec. Serv. Agreement (ESA) Between United Taconite LLC, Northshore Mining Co. (subsidiaries of Cliffs Nat. Res., Inc.), and Minn. Power*, Docket No. E016/M-16-534, ORDER OF THE COMMISSION at 1 (Nov. 9, 2016).

1. North Shore Loop Transmission Planning

Q. What is the North Shore Loop?

A. The North Shore Loop refers to an approximately 140-mile portion of 115 kV and 138 kV transmission lines in the northeastern Minnesota transmission system. The North Shore Loop extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center 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 2.

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 Minnesota Power's Laskin Energy Center and Taconite Harbor Energy Center, 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 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 Taconite Harbor Energy Center.[7] With Commission approval in the 2015 IRP (Docket No. E015/RP-15-690), Minnesota Power idled the other two Taconite Harbor Energy Center units in the fall of 2016 and ceased coal-fired operations at the facility in 2020.[8] In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally,

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[7] *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 7 at Order Point 3 (Nov. 12, 2013).

[8] *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 14 at Order Point 3 (July 18, 2016).

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 Energy Center, Taconite Harbor Energy Center, 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, and several more projects are planned over the next four years. 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 retiring 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 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.

Q. What are the redundancy impacts from shutting down local baseload generators?

A. When a local baseload generating facility consists of multiple generating units, redundancy is built into both the generation facility and the local power system. The Taconite Harbor Energy Center, for example, consisted of three 75 MW generating units. At any given time, the redundancy built into the generating facility meant that it was highly likely that at least two of the three units would be running, and it was virtually guaranteed that at least one unit would be running at all times. In that sense, Taconite Harbor provided a dependable source capable of delivering 75 MW to 150 MW of power to the North Shore Loop with a level of availability and reliability comparable to that of the transmission system. In the event of a planned or unanticipated transmission line outage, the generation facility could continue to provide power to the area, as its output could be adjusted up or down to mitigate transmission line loading or voltage issues.

In an area of the system where transmission sources are relatively sparse, like the North Shore Loop, local baseload generators can even be designed to operate with no transmission connections beyond the isolated area to restore electric service following multiple-contingency events resulting in loss of all transmission sources. Without these local baseload generators in the North Shore Loop, transmission system redundancy for the area has been lost. The resulting redundancy-related issues include post-contingent transmission line overloads, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area.

Q. What are the voltage support impacts from shutting down local baseload generators?

A. Local baseload generators provide reactive power and voltage support to the local transmission system. Electric power generated in an alternating current power system includes the generation of both real power — measured in MW — as well as reactive power — measured in megavolt-ampere reactive ("MVAR"). Reactive power is required to maintain an appropriate system voltage, stabilize the system, and enable the delivery of real power. Generators provide a dynamic source of reactive power that are able to ramp MVAR output up and down within the limits of the generator to regulate system voltage. This dynamic reactive support becomes particularly important for system stability, as abrupt changes in the power system can result in rapid voltage collapse if there is not a fast-responding source of reactive power. Unlike real power, which can be transmitted over long distances with relatively minimal losses, reactive power tends to be consumed locally by loads and by the transmission system itself. As more power is transferred on the transmission system, the reactive power needed to maintain appropriate system voltage increases. Without the local baseload generators in the North Shore Loop, the main sources of reactive power and voltage support have been lost. The resulting voltage-support-related issues include increased difficulty regulating transmission system voltage, post-contingent high or low voltage conditions, and increased risk of voltage collapse.

Q. What are the power delivery capacity impacts from shutting down local baseload generators?

A. As mentioned above, local baseload generators provide a dependable, available, and controllable source of power delivery to the local power system. Local customers benefit from the redundancy and voltage support provided by the local source of power. When baseload power is no longer provided locally, the replacement power must come from remote sources. In some cases, this can cause power flows on the transmission system well in excess of what the system was originally designed to accommodate.

The North Shore Loop was historically an area with sufficient, and at times excessive, amounts of local generation going back to the mid-1900s when the local baseload generators were built. As a result, the transmission system was not designed to accommodate significant flows into the North Shore Loop from remote sources. Without the local baseload generators online, the North Shore Loop now imports significant amounts of power over the 115 kV and 138 kV transmission system from remote sources originating at 230 kV/115 kV substations. The issues resulting from this changing use of the transmission system to replace the power formerly generated locally in the North Shore Loop include transmission line and transformer overloads as well as increased severity associated with outages that weaken or sever the connection to the remote sources of power now serving the area.

Q. What do you conclude from this discussion of the redundancy, voltage support, and power delivery capacity 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 amount of upgrading 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 has been learned about the North Shore Loop since the 2016 Rate Case?

A. At the time of the 2016 Rate Case, the Company's evaluation of the long-term needs in the North Shore Loop following the transition of local baseload generators was ongoing. Initial evaluations had identified several necessary transmission improvements, some of which were implemented before and during the 2016 Rate Case's 2017 test year. Since then, the Company has completed the evaluations necessary to determine the scope and timing of transmission upgrades in and adjacent to the North Shore Loop. Several additional projects have been identified and implemented by the Company since 2017, including four projects in the 2022 test year.

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 2022, 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.

The 2022 test year specifically includes (1) Phase 2 of the Mesaba Junction 115 kV Project, (2) the Forbes – Laskin 115 kV No. 38 Line ("38 Line") Extension Project, (3) the Laskin – Taconite Harbor Voltage Conversion Project, and (4) the Forbes Tie Breaker Project.

Q. Are there any other North Shore Loop-related projects that will be underway in 2022?

A. Yes. The Duluth Loop Project[9] will also incur spending in 2022 as it moves through scoping and permitting processes. No assets related to the Duluth Loop Project, however, are anticipated to be placed in service in 2022. Therefore, no capital additions related to this project are included in the test year plant in-service.

[9] *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); *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).

Q. What are the Mesaba Junction 115 kV Project and the 38 Line Extension Project, and what will they address?

A. The Mesaba Junction 115 kV Project and the 38 Line Extension Project involve, respectively, the development of a new "Mesaba Junction" switching station interconnected to existing transmission lines in the Hoyt Lakes area and the construction of approximately 5.4 miles of new 115 kV transmission along the existing Laskin – Hoyt Lakes transmission line corridor to extend the existing 38 Line into Mesaba Junction. The existing 38 Line connection to the Laskin Substation will be eliminated.

The Mesaba Junction 115 kV Project and the 38 Line Extension Project provide a third transmission source to the North Shore Loop to support redundancy, enhance reliability by providing a modern utility-controlled path for power flow into the North Shore Loop, and continue the process of offsetting the loss of voltage support and power delivery capacity formerly provided by local baseload generators in the North Shore Loop. The Mesaba Junction 115 kV Project, including the 38 Line Extension Project, has been reported in the Minnesota Biennial Transmission Projects Report since 2017 under tracking number 2017-NE-N23 (formerly as the "Hoyt Lakes 115 kV Project"). The first phase of the Mesaba Junction 115 kV Project, in which the new Mesaba Junction Switching Station was constructed, was completed in 2020. Construction on the 38 Line Extension Project and the second phase of the Mesaba Junction 115 kV Project is planned for completion in 2022 in coordination with construction of the Laskin – Taconite Harbor Voltage Conversion Project.

Q. What is the Laskin – Taconite Harbor Voltage Conversion Project and what will it address?

A. The Laskin – Taconite Harbor Voltage Conversion Project involves converting the legacy 138 kV system between the Laskin and Taconite Harbor substations to 115 kV operation. The Project includes removing 138 kV/115 kV transformers, replacing 138 kV equipment with 115 kV equipment, establishing a new transformer and feeder at the Skibo Substation, and replacing other aging equipment at the existing Laskin, Skibo, Hoyt Lakes, and Taconite Harbor substations. The project also includes minor upgrades to the existing transmission lines between Laskin, Mesaba Junction, and Taconite Harbor to increase their rated capacity when operating at 115 kV. The Laskin – Taconite Harbor Voltage Conversion Project enhances the reliability of the transmission system by eliminating single points of failure with long replacement lead times (138 kV/115 kV transformers) and providing a more redundant and reliable transmission connection for the North Shore Loop. In addition to these reliability benefits, the Project achieves the inherent benefits of replacing aging equipment, eliminating a non-standard voltage class (138 kV) from the Company's transmission system, and avoiding the cost of additional 138 kV/115 kV transformers for redundancy, replacement, or the establishment of new transmission connections (such as the 38 Line Extension mentioned above). The Laskin – Taconite Harbor Voltage Conversion Project has been reported in the Minnesota Biennial Transmission Projects Report since 2017 under tracking numbers 2017-NE-N2 and 2017-NE-N21. Construction of the Laskin – Taconite Harbor Voltage Conversion Project is being coordinated with the 38 Line Extension Project and the Mesaba Junction 115 kV Project and is planned for completion in 2022.

Q. What is the Forbes Tie Breaker Project and what will it address?

A. The Forbes Tie Breaker Project involves reconfiguring the existing 115 kV bus at the Forbes Substation to accommodate a redundant bus tie breaker. One existing transmission line exit will be relocated, and the existing bus will be expanded and reconfigured to make room for the second bus tie breaker. Asset renewal upgrades — such as the replacement of several existing 115 kV breakers, including the existing tie breaker and upgrade of the existing station service equipment — are also included as part of the project. Post-contingent overloads and low post-contingent voltages caused by internal fault or failure of the existing Forbes 115 kV bus tie breaker have been consistently identified in the annual MTEP assessment and the Company's internal studies. Increasing dependence on the Forbes 230 kV/115 kV source following the Company's transition away from the North Shore Loop baseload generators has increased the severity of these issues to the point where a solution has become necessary. Installation of a redundant bus tie breaker will eliminate the contingency causing these issues, and the included asset renewal project components will efficiently address age and condition related concerns at the substation. The Forbes Tie Breaker Addition is a predominantly transmission project that also involves distribution additions related to station service upgrades at the Forbes Substation. The Forbes Tie Breaker Addition Project has been reported in the Minnesota Biennial Transmission Projects Report since 2017 under tracking number 2017-NE-N6.

Q. Please describe the Duluth Loop, generally.

A. Although no assets related to the Duluth Loop Project are anticipated to be placed in service in 2022 and no capital additions related to this project are included in the test year plant in-service, the Duluth Loop Project is a part of the North Shore Loop transmission impacts and will be in progress in 2022.

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.

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

A. The Duluth Loop Project 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 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. The Duluth Loop

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 Project has been reported in the Minnesota Biennial Transmission Projects 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. Test year activities for the project include the continuation of scoping and permitting activities. Construction of the Duluth Loop Project is presently anticipated to begin in fall 2023, with targeted completion of the project in 2025. While scoping and permitting activities for this project will be underway in 2022, no portions of the project are anticipated to be placed in service in 2022; therefore, no capital additions for the Duluth Loop Project have been included in the 2022 test year plant in-service.

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. The projects discussed in my testimony and projects implemented prior to the 2022 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 must be 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 Taconite Harbor Energy Center units ceased coal-fired operation in 2020, projects like the Mesaba Junction 115 kV Project and 38 Line Extension, Laskin – Taconite Harbor Voltage Conversion, and Forbes Tie Breaker Project have been in a process of implementation that will see its completion when they are placed in service during the 2022 test year. 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 Project, which will not be fully implemented until 2025, is similar to these in that it 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 Project will be the final transmission project directly related to the impacts of fleet transition in the North Shore Loop.

Q. Does Minnesota Power need a Certificate of Need under Minnesota Statutes section 216B.243 and/or a Route Permit under Minnesota Statutes chapter 216E for any of the North Shore Loop projects?

A. Yes. As noted above, the Duluth Loop Project meets the threshold for requiring both a Certificate of Need and a Route Permit. A combined Certificate of Need and Route Permit Application for the Duluth Loop Project was submitted to the Commission under Dockets E015/CN-21-140 and E015/TL-21-141.

Q. Will Great River Energy or its cooperatives served by the North Shore Loop transmission system be providing any cost support for any of the North Shore Loop projects?

A. As a general principle, where projects involve the transmission system jointly used by the Company and Great River Energy, each party pays for the improvements to the transmission assets it owns. Because the vast majority of the North Shore Loop projects have involved only Minnesota Power-owned transmission lines and substations, Great River Energy has directly contributed to only one project in the Two Harbors area where a Great River Energy-owned facility was involved. However, Great River Energy does compensate Minnesota Power for the use of transmission assets — including new assets

— through the JPZ Agreement as described in Section IV.B.2 of my Direct Testimony. Through the JPZ Agreement, the cost of Minnesota Power's North Shore Loop project investments will be shared appropriately by Great River Energy.

2. Grand Rapids Area Transmission Planning

Q. Please describe the transmission system in the Grand Rapids area.

A. The Grand Rapids area is served by a 115 kV system including the Boswell, Blandin, Lind-Greenway, Grand Rapids, and Tioga substations. Three 115 kV transmission lines connect the Grand Rapids area transmission system to 230 kV/115 kV sources at the Blackberry and Riverton Substations. These transmission lines are the Nashwauk – Canisteo – Boswell 115 kV Line, the Blackberry – Grand Rapids/Blandin 115 kV Line, and the Riverton – Grand Rapids 115 kV Line. While four coal-fired generators were historically located at the BEC, only BEC Units 1 and 2 were interconnected to the Grand Rapids area 115 kV system. BEC Units 3 and 4 interconnect directly to the 230 kV system and, prior to the upgrade discussed below, the nearest 230 kV/115 kV transformer that tied back to the Grand Rapids area 115 kV system was located at the Blackberry Substation. There was no local electrical connection between the 230 kV and 115 kV systems in the Grand Rapids area, in part because the 115 kV system was supported by the baseload operation of BEC Units 1 and 2. The transmission system in the Grand Rapids Area is depicted in MP Exhibit ___ (Gunderson), Direct Schedule 3.

Q. How did BEC Units 1 and 2 support the Grand Rapids area transmission system prior to their retirement?

A. The BEC Units 1 and 2 local baseload generators contributed to the reliability of the Grand Rapids area transmission system for decades by providing redundancy, voltage support, and power delivery capacity, among other things.

Q. What impacts did the retirement of BEC Units 1 and 2 have on the Grand Rapids area transmission system?

A. Without the redundancy, power delivery capacity, and voltage support formerly provided by BEC Units 1 and 2 to the 115 kV system, contingencies impacting one or more transmission facilities in the Grand Rapids area may lead to transmission line overloads, post-contingent high or low voltage conditions, increased risk of voltage collapse, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area.

Q. What projects has Minnesota Power implemented to address these transmission system impacts?

A. Minnesota Power completed a project in 2019 to establish a new 230 kV/115 kV source in the Grand Rapids area by expanding the existing Boswell 230 kV Substation and connecting it to the existing 115 kV system. No additional projects are necessary at this time in the 2022 test year.

3. Additional Transmission Planning

Q. What additional work is Minnesota Power doing to prepare for the future of transmission grid needs?

A. In addition to the transmission planning practices discussed so far in my testimony, several areas of additional study and coordination are currently taking place to prepare for the future of transmission grid needs. On a regional level, as discussed in greater detail in Section III.F of my testimony, the Company is an active participant with MISO in the Long-Range Transmission Plan ("LRTP") effort and with Grid North Partners (formerly CapX2020 Initiative) in transmission planning initiatives that will be foundational to meeting the long-term needs of an evolving regional electric grid. The Company's 2021 IRP (Docket No. E015/RP-21-33) also highlights the extensive study work that the Company has undertaken to begin to understand the transmission impacts associated with changing operations of BEC Units 3 and 4, which are the last remaining baseload generators on the Company's system and in all of Northern Minnesota.

Q. What information is provided in the Company's 2021 IRP related to transmission impacts resulting from the changing operations of BEC Units 3 and 4?

A. In its 2021 IRP and the Baseload Retirement Study included with the 2021 IRP, the Company describes 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."[10] The six pillars are informed by recent experience from the transition of smaller coal units in the North Shore Loop and the Grand Rapids area, 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 IRP, 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. Is all of the transmission planning related to this fleet change complete?

A. As noted in Appendix F, Part 8 of the 2021 IRP, there is a "considerable amount of work left to understand and develop long-term solutions to the transmission issues discussed in [Appendix F,] Part 7."[11] The Company continues this work, advancing transmission studies that build upon the analysis presented in the 2021 IRP to identify and develop appropriate solutions that can be inserted into the Company's transmission plan and implemented at the appropriate time to prepare the transmission system for eventual changes in operations of the BEC units. The Company's internal efforts in this area are also being coordinated with neighboring utilities directly and through the regional MISO LRTP and Grid North Partners efforts. In summary, the Company has been — and continues to be — very engaged in proactively planning for the long-term transmission needs of its customers and the Northern Minnesota region, and it is

[10] *In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E015/RP-21-33, APPENDIX F at 40 (Feb. 1, 2021).

[11] *In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E015/RP-21-33, APPENDIX F at 56 (Feb. 1, 2021).

expected that continued investment in the transmission system will be necessary to ensure the long-term reliability of the system as the local and regional generation fleet continues to evolve.

C. <u>Distribution Capital Investments and Projects</u>

Q. How is Minnesota Power categorizing Distribution capital project information in this rate case?

A. Minnesota Power has adopted the categories outlined in the Integrated Distribution Plan ("IDP"), filed on October 25, 2021 (Docket No. E015/M-21-390), for purposes of discussing the Company's Distribution capital. The IDP addresses the requirements outlined by the Commission, and the Company uses the IDP in addition to its normal capital planning processes to build internal consensus on the direction of future projects impacting the planning and operation of the distribution system and to facilitate an integrated planning approach that brings together distribution planning, transmission planning, and resource planning. The IDP also provides an opportunity for interested stakeholders to provide input on the Company's current and future plans. Minnesota Power's IDP utilizes the following categories, which are also used in this rate case filing for purposes of the Company's capital additions (Table 1 and Table 2 above) to allow for consistency across filings. The categories required for the IDP are:

- Age Related & Asset Renewal;
- System Expansion or Upgrades for Capacity;
- System Expansion or Upgrades for Reliability and Power Quality;
- New Customer Projects and New Revenue;
- Grid Modernization and Pilot Projects;
- Government Requirements;
- Metering; and
- Other.

The categories listed above are the short-hand category titles used in Table 1 and Table 2 above and in the IDP. These categories are discussed in further detail below.

Q. How are Distribution capital projects identified?

A. Distribution capital projects are identified through a variety of methods. The majority of Minnesota Power's capital spending addresses asset replacements that are generally age-related. Some of these replacements are identified through inspection programs, such as ground-line or pole maintenance inspections, while some are in response to difficult-to-predict failures. Past practice and historical averages inform the annual budget for cable and switch replacements and help predict where replacement of other failed assets may become necessary. Age-related Replacements and Asset Renewal projects are also identified through local engineering expertise and experience with failures on the system. Some other means of identifying areas for replacements and asset renewals are use of Geographic Information System ("GIS") applications such as Survey123 and Collector by technicians out in the field. These applications are used to collect issues in the field and funnel that work automatically into our work management system. At the transmission-to-distribution substation level, previously unconnected asset renewal programs have been integrated into a single substation modernization program designed to efficiently and holistically address all of the asset renewal needs at a site with one comprehensive project.

Projects may also be identified through system modeling and analysis. Distribution planning performs baseline system analysis on the distribution system, generally in conjunction with the planning of substation modernization or feeder automation projects. The types of projects identified through this means most often involve improvement of feeder capacity and voltage support in order to maintain or enhance backup capability and redundancy. Such projects would typically be categorized as "System Expansion or Upgrades for Capacity" and "System Expansion or Upgrades for Reliability and Power Quality" — though sometimes they may also support Grid Modernization Projects that make use of full-capacity feeder ties by enhancing or automating restoration capability.

Q. Can external needs impact how Distribution projects are identified?

A. Yes. There are multiple external drivers of projects — in particular, local government and customer needs. The Distribution capital budget addresses the need to respond to road relocations, new commercial and residential development, and other customer needs.

Q. Are there strategic projects in the Distribution capital budget?

A. Yes. There are a number of strategic projects in the Distribution capital budget as well. These are identified as part of broader strategic Minnesota Power initiatives that directly benefit the Company's customers. An example of a strategic project would be the Company's state-leading deployment of AMI, a multi-year concerted effort that has already resulted in numerous customer benefits discussed in Section V.C.1 of my Direct Testimony.

Q. How is the Distribution long-range plan developed?

A. The Distribution long-range plan is reviewed comprehensively on an annual basis. The Distribution Engineering and Distribution Planning departments coordinate the development of the plan, including projects affecting transmission-to-distribution substations, as well as distribution feeders and step-downs. The long-range plan incorporates localized distribution system reliability and asset renewal needs as identified by Distribution Engineering, as well as larger-scale projects coordinated by Distribution Planning where transmission-to-distribution substation reliability, capacity, or asset renewal projects are necessary. Other projects and programs for asset renewal, grid modernization and pilot projects, required relocations, metering, and new customer interconnections are also included in the long-range plan, as identified by Distribution Engineering and Distribution Planning.

The long-range plan generally utilizes historical spending to establish amounts for routine maintenance. Specific projects are slotted into the plan based on timing and need, as identified through asset renewal prioritization, system analysis, or external constraints. Many of these specific projects require close coordination with customers, local government, or other business groups within the company. Because many projects are dependent on timelines and needs outside of the Company's control, a fair amount of changes occur naturally in the long-range plan as the Company learns more information.

Q. What are Age Related Replacements and Asset Renewal Projects?

A. Similar to the transmission system, distribution system Age Related Replacements and Asset Renewal Projects are used to replace failing and end of life distribution system infrastructure. Some age-related replacements and asset renewal projects are planned in advance and implemented proactively as engineers identify and prioritize age- and condition-based replacements or areas prone to failure based on reliability metrics and feedback from field crews. Other Age Related Replacements and Asset Renewal Projects are implemented in response to unanticipated failures. Engineering expertise helps prioritize proactive age-related and asset renewal efforts. In some cases, the Company experiences a number of failures in a certain area of the system or with a particular type of asset, and these failures inform where to direct capital spending. However, some age-related replacements also naturally occur throughout the year due to unanticipated failures. At the transmission-to-distribution substation level — where failures can be more broadly impactful, costly, and have longer lead times to fix — proactive asset renewal modernization projects have been identified and prioritized based on the age, past performance, and direct customer impact of major substation apparatus.

Q. What are the main drivers for these projects?

A. The main drivers for these projects are age and condition. With many assets more than 40 years old, asset management programs and investments have increasingly become an area of significant focus for the Company.

Q. What are examples of Age Related Replacement and Asset Renewal Projects in the 2022 test year?

A. Ground-line restoration is an example of an Age Related Replacement and Asset Renewal Project on the distribution system. Ground-line inspections are conducted on every distribution pole over a ten-year period. External contractors visit the poles throughout the year, excavate the base of the poles, and test the shell thickness of the pole to determine if the pole is at the end of its useful life. Engineering then reviews the results and remediates all issues found. The ground-line program will be improved starting in 2022, as discussed below.

The replacement of the existing Silver Bay Hillside 115 kV/14 kV Substation with a new transformer in the nearby North Shore Switching Station (i.e., North Shore Transformer Addition) is an example of an Age Related Replacement and Asset Renewal Project at the transmission-to-distribution substation level. This project is also discussed below.

Q. How will the ground-line program be improved in 2022?

A. The ground-line inspection process will now be more in-depth to extend the lives of poles and capture long-term cost savings for customers. The inspections will now involve a full excavation around the base of the pole, which will drive one of three possibilities. First, if the pole has no issues, the base of the pole will be treated for mold or insects. Second, if the pole fails inspection, it will be identified for truss placement around the base of the pole. Third, if the pole is rejected, it will require a pole replacement. The updated ground-line inspections will result in capital projects that extend the lives of the poles.

Q. What is the North Shore Transformer Addition Project, and what will it address?

A. The North Shore Transformer Addition Project involves adding a new 115 kV/13.8 kV transformer at the existing North Shore Switching Station and reconfiguring the existing distribution system to tie into the new transformer. An existing 115 kV capacitor bank will be relocated within the North Shore Switching Station to accommodate the addition of the new transformer. The North Shore Transformer Addition project will allow the existing Silver Bay Hillside Substation to be retired, demolished, and converted to a mobile substation site to provide emergency backup for the City of Silver Bay. The project is necessary to replace the Silver Bay Hillside Substation, which includes original components dating back to 1951. The new transformer at the North Shore Switching Station was identified as the preferred solution over rebuilding the existing Silver Bay Hillside Substation due to outage and construction limitations associated with the scope of work required to adequately modernize the Silver Bay Hillside Substation in its present location. The North Shore Transformer Addition Project is a predominantly distribution project that also involves 115 kV transmission modifications at the existing North Shore Switching Station. The project is part of a relatively recent effort by the Company to identify and prioritize holistic substation modernization Asset Renewal Projects.

Q. What are System Expansion or Upgrades for Capacity?

A. System Expansion or Upgrades for Capacity projects are projects that increase the baseline load-serving capacity of the distribution system. For example, if voltage or capacity issues are identified because of load growth on a circuit, the Company may need to reconductor a portion of a circuit to ensure continued reliable service. In the past, the Company has also needed to build new distribution substations from time to time in order to increase load-serving capacity.

Upgrades for Capacity are often secondary benefits of implementing a reliability project or an asset renewal project. Many projects provide benefits in all three areas, and identifying the primary category for such projects is not a precise exercise. A project with a strong reliability component, such as reconductoring a section of feeder to a tie switch to ensure adequate backup capability for planned or unplanned outages, might also increase the capacity of the feeder. Although the main purpose of the project is to reliably serve load from another source during an outage, there is an inherent increase in capacity gained as well. The very same project may also involve the replacement of end-of-life poles and conductor, thus achieving a strong asset renewal benefit at the same time. Ideally, existing capacity chokepoints are identified through the Company's proactive system modeling and distribution planning practices, though they may sometimes be discovered by field crews or during a switching event. Sometimes these capacity limitations are limited to a few spans of undersized conductor. The Company does not currently have many load-serving constraints on the system during normal conditions. Feeder backup capability is being evaluated and improved methodically by distribution planning in coordination with the development of substation modernization asset renewal projects and grid modernization projects.

Q. What are the main drivers for System Expansion or Upgrades for Capacity?

A. The main driver of System Expansion or Upgrades for Capacity is load growth. This load growth is almost always driven by commercial and industrial customers. Upgrades for Capacity may not arise due to any single new customer but often are needed after many years of concentrated load growth on a capacity-constrained area of the system. As noted above, capacity improvements may also be achieved incidentally or intentionally as part of multi-purpose projects that also involve strong age and condition, reliability, and grid modernization components.

Q. What is an example of a System Expansion or Upgrade for Capacity in the Rate Case?

A. Relatively few projects in the 2022 test year are driven primarily by a need for increased system capacity. One example is the expansion of the Canosia Road 115 kV/34.5 kV Substation to accommodate a new 34.5 kV feeder in the Cloquet area (i.e., Canosia Road Substation 34.5 kV Expansion). This project also has strong reliability, age and condition, and even grid modernization components to it.

Q. What is the Canosia Road Substation 34.5 kV Expansion, and what will it address?

A. The Canosia Road Substation 34.5 kV Expansion involves expansion of the existing Canosia Road Substation to accommodate a new 115 kV/34.5 kV transformer, as well as extension of a new 34.5 kV feeder from Canosia Road to the existing Scanlon 24 kV/14 kV Substation. A new Cloquet East Side 34.5 kV/14 kV stepdown will be established near the Scanlon Substation, and the existing 24 kV system will be updated and converted to 34.5 kV from Scanlon to the existing step-downs at Moorhead Road and Sawyer. The Moorhead Road and Sawyer step-downs will also be replaced in coordination with the project. New fiber optic communications will be routed in conjunction with the new and converted 34.5 kV feeder to enhance visibility and control of the distribution system in the area and prepare for a future fault location, isolation, and system restoration ("FLISR") project once 34.5 kV is established to the Mahtowa Substation on the other end of the local area backbone distribution system. The Canosia Road Substation 34.5 kV Expansion will be the first step and foundation in a multi-year plan to modernize and improve the Cloquet-area distribution system.

Q. What is driving the need for the Canosia Road Substation 34.5 kV Expansion?

A. There are several factors driving the need for improvements in the Cloquet area:

1) Asset Renewal & Standardization: The project will continue implementation of a standard 34.5 kV backbone distribution network for the Duluth/Cloquet area. There are presently three different backbone distribution voltages between Duluth, Cloquet, and Hinckley. The Canosia Road 34.5 kV Expansion and subsequent projects will convert existing 24 kV and 46 kV systems to 34.5 kV while addressing asset renewal needs for existing feeders and step-downs associated with these systems;
2) System Capacity & Asset Renewal Project Constructability: The project will enable a comprehensive Cloquet Substation Modernization Asset Renewal Project to take place. The Cloquet Substation is one of the highest-priority asset renewal sites in the Minnesota Power system, but the distribution system lacks sufficient capability to reliably support the Cloquet area during the extended outage of the Cloquet Substation that would be needed to implement the Asset Renewal Project; and
3) Reliability & Grid Modernization: The project will improve reliability for Cloquet-area customers by reducing feeder exposure, providing backup capability from new feeders and 34.5 kV/14 kV step-downs, and enabling feeder automation projects to be implemented for enhanced visibility and rapid system restoration.

The Canosia Road Substation 34.5 kV Expansion Project is a predominantly distribution project that also involves 115 kV transmission additions at the existing Canosia Road Substation.

Q. What are System Expansion or Upgrades for Reliability and Power Quality?

A. System Expansion or Upgrades for Reliability and Power Quality are projects that directly benefit customer reliability. Often these projects involve building or strengthening ties to other feeders to more easily restore power to customers during outage events. These projects can be identified through field experience, analysis of reliability data, and system planning.

Q. What are the main drivers for System Expansion or Upgrades for Reliability and Power Quality?

A. Improving operational flexibility and customer reliability are the main drivers of these projects. If a certain area experiences exceptionally poor reliability over a short period of time, engineers and planners may evaluate the local system and identify a potential reliability improvement. Field crews are also invaluable resources for feedback on areas of the system that could benefit from additional operational flexibility. Power quality issues are primarily identified through customer reporting and power quality monitoring. With the prevalence of AMI on the system, the Company has been able to identify areas of the system with power quality issues before customers notify the Company.

Q. What is an example of a System Expansion or Upgrade for Reliability and Power Quality in the 2022 test year?

A. The Canosia Road Substation 34.5 kV Expansion Project described above is an example of a project that strongly fits the System Expansion or Upgrade for Reliability and Power Quality category. In fact, for internal purposes and for reporting in the IDP, the Company considers the project benefits and costs to be a 50-50 split between the Capacity and Reliability categories.

An example of a reliability improvement project is the rollout of voltage regulators in various areas of the Company's distribution system. Voltage regulators are routinely installed on the system in order to control feeder voltage and mitigate end-of-line power quality issues. Distribution voltage regulators help to shield distribution-connected customers from the negative impacts of wide variations in system voltages by maintaining a consistent feeder voltage profile across a wide array of system conditions. These types of reliability improvements are becoming more necessary as transmission voltages become more unpredictable due to the retirement or idling of local baseload generators and as large distribution-connected generators or aggregations of small-scale distribution-connected generators produce less predictable system conditions locally on the feeders.

Q. What are New Customer Projects and New Revenue?

A. New Customer Projects and New Revenue includes construction of distribution line extensions to serve new customer load. Most new customer projects result in new (i.e., increased) revenue to the Company. A small number of customer projects are revenue neutral. While most individual line extensions are less than $2,000, the distance from existing facilities to the new service point is the most common condition that will determine the cost. Line extensions are made in accordance with the Company's Electric Service Regulations and Commission-approved tariffs. The extension rules specify an allowance (i.e., credit) for each rate class. Extension costs that exceed the allowance are paid by the customer or may be covered by a guaranteed annual revenue agreement (excluding single-phase services) if the customer enters into a five-year electric service agreement.

Q. What are the main drivers for New Customer Projects?

A. The Company has an obligation to serve new load within our service territory, and the main drivers for New Customer and New Revenue Projects are customer requirements. While overall residential and commercial kWh energy sales are declining across the service territory, construction spending for customer and revenue projects has remained stable for nearly ten years.

Q. How have New Customer Projects been affected during the COVID-19 Pandemic?

A. There has been an increase in customers moving into Minnesota Power's service territory by relocating into previously seasonal properties that are now becoming their permanent residences due to remote work capabilities. During this time, the Company also received an increase in requests for camper services where customers have indicated they intend to build when supply chain issues stabilize.

Q. What are examples of New Customer Projects?

A. New customer projects and new revenue are limited to line extensions on the Company's Distribution System. Over the last two years, on average, new connects are 45 percent commercial, 54 percent residential, and one percent municipal and industrial.

Over the two-year period of 2019 and 2020, there was an annual average of 1,602 work orders written for new customer connects. Streetlights and area lights are also considered line extensions, but instead of being metered, they provide fixed revenue per fixture. In addition, there are customer projects that do not result in any increased sales (i.e., revenue). For example, a customer requests an extension to a new service point but is going to retire the existing connection to the system and is not adding new load. The new extension is revenue neutral (i.e., no net sales increase or decrease).

Q. What are Grid Modernization Projects?

A. Grid Modernization Projects are efforts that go beyond the Company's baseline efforts to maintain safe, reliable, and affordable energy but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. These projects are identified and selected by analyzing reliability metrics and determining what solution or suite of solutions is best suited to improve reliability on the system. Most often, this involves the deployment of more intelligence on the distribution system such as line sensors, motor operated switches, automatic switches, fault indicators, and trip savers. The Company is also in the process of rolling out a multi-year plan to install smart switches (i.e., IntelliRupters) and the associated communications infrastructure improvements in strategic locations on the distribution system. Increased information from the distribution system helps improve customer communications and reliability of service.

Minnesota Power is planning to make significant investments to modernize the Distribution grid over the next decade as described more fully in the 2021 IDP. In general, increased spending will be focused on grid modernization, strategic undergrounding, and pilot projects. Current plans include drastically increasing the number of FLISR devices installed on the system as noted above. The Company is also working on implementing a remote motor operated switch pilot to increase reliability in areas further from service centers by enabling system operators to remotely operate switches to isolate a faulted section of feeder and restore service to as many customers as possible. The Company began a strategic undergrounding initiative in 2020 by burying approximately one mile of primary three-phase and more investment in strategic undergrounding is planned in coming years.

Q. Please explain Pilot Projects that the Company undertakes.

A. Pilot projects are the Company's efforts to work with new and emerging applications on the distribution system. Pilots are most often projects and technology that the Company has little to no experience with but are meant to facilitate learning and ensure that an effort is worth pursuing on a larger scale before expending large amounts of capital. One key advantage of piloting technology on the Distribution System is that a thesis can generally be proven at a small scale utilizing metrics and benefits and expanded to larger levels and optimized accordingly, without significant risk to customers if the technology or application is determined to not be cost-effective. The Company has pursued a number of pilot projects in the past that have resulted in tangible customer benefits, cost savings, and important lessons learned. Since 2016, the Company piloted the use of Trip Savers, a cutout mounted recloser, to improve reliability on areas of the system that often experience temporary faults and that are relatively far away from a service center. This pilot resulted in a reduction in the number of outages, which subsequently reduces the need to dispatch a service truck and lowers trouble costs. The Company has since increased deployment of these devices in a more structured program since the onset of the pilot. Moving forward, the primary goal of pilot projects is to find more cost savings and customer benefits with new and emerging technology and applications.

There have also been a number of challenges associated with modernizing the grid and implementing pilot projects. Moving to a more complex distribution system with intelligent devices requires close internal coordination across many departments, some of which have not previously needed to be involved with the planning, construction, and operation of the distribution system. The Company is working on developing communications infrastructure plans dealing with new cyber security concerns as more intelligent devices are installed on the system. More detailed information about Grid Modernization and Pilot projects can be found in the Company's 2021 IDP.

Q. What are the main drivers for Grid Modernization and Pilot Projects?

A. The main drivers for Grid Modernization and Pilot Projects are reliability, safety, cost savings, increasing internal knowledge and experience with new and emerging technologies, and keeping pace with regulatory requirements and customer expectations. Minnesota Power's Grid Modernization Projects are typically deployed on systems that have lower reliability performance, as the benefit to customers is greater on underperforming systems. This increased knowledge is used to improve reliability and provide better information to our customers during an abnormal event.

Q. What are projects related to Local Government Requirements?

A. The most common Local Government Requirements are relocation of lines located in public rights-of-way and relocation of distribution lines to avoid road construction conflicts. By the rules of the governing authority having jurisdiction, most projects are not reimbursable to Minnesota Power by local governments. Only relocation of existing lines outside road rights-of-way and protected by private property rights may be reimbursable.

Q. What are Metering Projects?

A. Metering Projects are related to the procurement, installation, and communications of energy measurement technologies used for financial transactions. Minnesota Power has historically deployed AMI throughout its service territory at a rate of approximately six to eight percent per year. In 2020, the Company was able to increase AMI installations significantly by redirecting the work assignments of the Meter Reader Collector group while a Commission-ordered stay on residential and small commercial disconnections was in effect (Docket No. E,G999/M-20-375). With the pause in field collections due to COVID-19, the Meter Reader Collectors had an opportunity to redirect their efforts. As field collections resume, and with the remote/hard to access nature of remaining meters, AMI installations are expected to return to historical levels going forward as discussed in Section V.C.1 of my Direct Testimony.

Q. What are the main drivers for Metering Projects?

A. The main drivers include:

- Supply usage information to our customers. Interval usage information is loaded into the MyAccount customer portal available on the Minnesota Power website and through the Minnesota Power app;
- Increased communications failures, unsupported technology, or limitations of the technology of the legacy Automated Meter Reading ("AMR") system due to end of life and obsolescence of technology. These meters are replaced with AMI meters, decreasing the frequency of billing estimations;
- Integration of AMI and the Outage Management System ("OMS"). Every AMI meter acts as an outage detection sensor and also reports power restorations;
- Replacement of the aging dual fuel and controlled access control systems. AMI meters replace legacy socket collars, and are controlled with the AMI system, which allows for future improvements that support reliability with increased variable renewable energy on the system; and
- More timely and cost-effective restoration of service to customers who have been disconnected by using meters with remote disconnect/reconnect capability. This technology is being deployed on a limited basis through Minnesota Power's

Reconnect Pilot Program, described in Docket No. E015/M-19-766. The Company estimates up to ten percent or approximately 12,250 residential customers will have remote capable AMI meters and be eligible for this Pilot.

Q. What are the Distribution "Other" projects?

A. Projects included in the "Other" category improve Distribution assets operations but do not meet the above-listed categories or drivers. Some examples include replacing assets due to damage incurred to our system by an unidentified third party for which the Company cannot receive reimbursement or due to storms, but the largest recent project in this category is the Street and Area Light Replacement Project, described below.

Q. What is the Street and Area Light Replacement Project?

A. The Street and Area Light replacement project started in 2020 and will be completed in 2022. This project converts all older technology street and area lighting to more energy efficient LED technology. Company witness Leah N. Peterson discusses the impacts of this transition on our rate offerings in her Direct Testimony.

D. <u>Cost Recovery Rider</u>

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

A. Yes, one project currently in the TCR, Dog Lake, is in-service and will be transferred from the TCR to recovery in base rates with the implementation of proposed rates. The Direct Testimony of Company witness Stewart J. Shimmin provides additional information regarding this roll-in.

Q. What is the Dog Lake Project and why was it needed?

A. The Dog Lake Project is part of the larger Motley Area 115 kV Project. On March 19, 2015, Minnesota Power and Great River Energy jointly filed a combined Certificate of Need Application (Docket No. ET2, E015/CN-14-853) and Route Permit Application (Docket No. ET2, E015/TL-15-204) to the Commission for the proposed Motley Area 115 kV Project. The overall project was needed to address local load-serving and power-system overload issues in the area, as well as establishing service to a new oil-pipeline pumping station. The Company's part of the project was completed, and all portions of the project were placed in-service in fall 2017.

Q. Did Minnesota Power prudently incur the costs it spent to complete the Dog Lake project?

A. Yes, the costs incurred by the Company to complete the Dog Lake project were prudently and reasonably incurred to complete this necessary project. Through the usage of Handy-Whitman factors, the Minnesota Power Project Estimate for the project was $3.9 million (2014$) which increases to $4.2 million (2018$) Total Company ($3.5 million MN Jurisdictional). Minnesota Power was able to construct this project slightly ($14,121)[12] over the cap of $3.93 (2014 $) at $4.2 million Total Company ($3.5 million MN Jurisdictional).

Q. What does the Company request the Commission do with the costs for the Dog Lake project?

A. Minnesota Power requests that the Commission allow the Company to recover all Dog Lake project costs, including those currently in the TCR plus additional amounts not in the rider, in base rates, as described by Company witness Mr. Shimmin.

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

A. Yes. On July 9, 2019 the Company submitted its TCR Petition (Docket No. E015/M-19-440) for the cost recovery of the Company's portion of the Great Northern Transmission Line's construction costs. The project was first energized and placed into service as planned in summer 2020. The Company is pleased to report that, in addition to completing the project on schedule, the construction costs were on budget and near the low end of the projected cost range in accordance with the project's Certificate of

[12] The project cap changed slightly because the Handy-Whitman Indices actuals varied slightly from the projected Indices used in the March 19, 2015 Certificate of Need and Route Permit applications.

Need approval stipulations (Docket No. E015/CN-12-1163). On December 3, 2020, the Commission approved the Company's petition (as updated in supplemental reply comments) to include the Great Northern Transmission Line in its TCR.[13]

Minnesota Power is not requesting Commission approval to move recovery of Great Northern Transmission Line project costs from the TCR to base rates at this time. On December 28, 2020, Minnesota Power submitted its Petition ("2021 TCR Petition") (Docket No. E015/M-20-900) seeking Commission approval of the Company's 2021 rate adjustment mechanism under its TCR. Components of the Great Northern Transmission Line revenue requirements, such as the first-of-its-kind Must Take Fee, add a level of complexity other projects, like the Dog Lake Project, do not possess. While the 2021 TCR Petition was still being evaluated in the regulatory review process, and with uncertain timing as to when it would reach a conclusion, the Company was in the late stages of developing assumptions as the basis for its upcoming rate case. The Company determined that maintaining recovery of Great Northern Transmission Line costs through the TCR, at the present time, was optimal for evaluating prudency and transparency of costs. Minnesota Power expects to seek approval for recovery of Great Northern Transmission Line Costs, including internal labor costs, in base rates in the next future rate case following the resolution of the 2021 TCR Petition.

Q. Are there any other transmission projects that the Company anticipates it will eventually include in the TCR?

A. The Company is also in the early stages of permitting the Duluth Loop Project, which is expected to be a TCR-eligible project pending approval by the Commission of the Company's Certificate of Need Application (Docket No. E015/CN-21-140). The Duluth Loop Project is discussed in greater detail in Section III.B.1 of my Direct Testimony.

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[13] Further discussion of the Great Northern Transmission Line's construction costs related to the TCR and this rate case are included in the Direct Testimony of Company witness Mr. Shimmin.

E. Renewable Interconnection

Q. Please describe Minnesota Power's efforts related to renewable interconnection.

A Minnesota Power works in a variety of ways to ensure renewables can be interconnected to our system safely and efficiently. For many years, the Company's SolarSense rebate program has offered customers the opportunity to receive a substantial rebate on installing customer-sited solar projects. The vast majority of solar applications that the Company receives each year are incentivized by this rebate and it is the primary driver for Distributed Energy Resources ("DER") adoption in our service territory. The Company also participates in the Distributed Generation Working Group to develop technical standards, garner feedback from stakeholders, and ultimately to refine internal processes.

In late 2018, the Company also became part of the Electric Power Research Institute ("EPRI") Distribution Resource Integration and Value Estimation Tool ("DRIVE") User Group to gain understanding of hosting capacity analysis and the data and labor requirements for performing hosting capacity studies. The Company is continuing to improve its use and knowledge of EPRI DRIVE for hosting capacity. DRIVE is a promising tool and it is the Company's hope to use it more broadly over the next few years to augment its distribution planning and distributed generation interconnection processes, especially as small-scale DER installations continue to be concentrated in a few specific areas of the Company's distribution system.

In 2021, the Commission approved Minnesota Power's proposal to build three new solar arrays at Laskin Energy Center, Duluth, and Sylvan Hydro as part of our Energy***Forward*** strategy to transition to a more renewable grid and zero carbon future while also supporting the economic recovery of Minnesotans following the COVID-19 pandemic (Docket No. E015/M-20-828). These projects are currently in development and no associated costs are in the 2022 test year, as these projects are eligible for recovery through the Solar Factor of the Renewable Resources Rider.

F. <u>Regional Transmission Development</u>

Q. Please describe Minnesota Power's efforts related to transmission development in the region.

A. As described in Section III.B of my testimony, MISO conducts and Minnesota Power contributes to an annual MTEP study process. Periodically, MISO also conducts additional transmission studies to look more broadly at long-term transmission needs, focusing on the big picture of regional and interregional infrastructure. In 2020, MISO announced it would begin a LRTP effort as part of a broader Reliability Imperative. Increasing renewable generation, continuing retirements of conventional baseload generation, and expected changes in load through electrification will bring challenges to the reliability of the transmission system. MISO's LRTP is a multi-year initiative to develop potential transmission solutions for those challenges, starting from a base of the utility and state plans on where to site new resources. LRTP will develop a comprehensive "transmission roadmap" with identified solutions moving to the ongoing MTEP processes for approval.

Minnesota Power is actively engaged in MISO's LRTP initiative. Multiple employees attend LRTP-related presentations, committee meetings, and workshops to keep abreast of activities. In addition, Minnesota Power engineers review and provide feedback on MISO's published models and meet with MISO's transmission planning engineers to discuss concerns specific to northern Minnesota and the interests of Minnesota Power's customers. Minnesota Power also participates in Grid North Partners to plan future transmission needs.

Q. What is Grid North Partners?

A. Grid North Partners (an outgrowth of the CapX2020 Initiative) is a group of ten investor-owned and not-for-profit cooperative and municipal utilities working together to ensure continued safe, reliable and affordable electric service to their customers in the Upper Midwest. Minnesota Power has been a member of CapX2020 since its inception in 2004 and is proud to continue in this collaborative organization under its new name, Grid North Partners. In 2020, the group released the CapX2050

Transmission Vision Report[14] and, in June 2021, produced the Finding True North Conference,[15] a half-day online dialogue with industry experts, regulators, and other stakeholders discussing the needs of the transmission system in the Upper Midwest. Along with one other Minnesota Power senior leader, I had the opportunity to participate in the conference as a panel speaker. Minnesota Power's management and technical staff are active participants in Grid North Partners, including contributing to the aforementioned report and conference. The Company's engineers collaborate regularly with their peers on the Grid North Partners technical team, which has also met with MISO's LRTP engineers to discuss transmission needs in the Grid North Partners footprint.

As the electric grid continues to transition, Minnesota Power will continue to cooperate and communicate with neighboring utilities, MISO and organizations like Grid North Partners to bring cost-effective solutions that maintain reliability for customers.

IV. TRANSMISSION AND DISTRIBUTION O&M

A. O&M Budget Overview

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

A. The consolidated annual budget process is described in the Direct Testimony of Company witness Mr. Rostollan. Each year, the work areas in Transmission and Distribution (and related support services) prepare a zero-based budget. The budget is typically submitted during the second quarter of the prior year. As with capital, the Company undertakes a zero-based (i.e., bottom-up) approach to budgeting, as further described by Mr. Rostollan.

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[14] *CapX2050 Transmission Vision Report*, CapX2020 (Mar. 2020), https://gridnorthpartners.com/wp-content/uploads/2021/02/CapX2050_TransmissionVisionReport_FINAL.pdf.

[15] *Finding True North Conference*, Grid N. Partners (June 16, 2021), https://gridnorthpartners.com/conference/.

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

A. Each work area follows a collaborative process facilitated by a Budget Analyst and the Budget Owner, using information from various systems, databases, and departments. The budgeting process considers the work expected to occur the following year, taking into account the current workforce and how their time may be allocated across capital, O&M, or billable work, as well as anticipated changes in salary, pay grades, and head count. The analyst reviews prior data to gain the historical view of spend, then applies appropriate methodology to the various components to develop the budget. Technological advancements and efficiency gains are considered, outlying events are normalized, and one-time events are excluded. Known and measurable changes expected to take effect in the upcoming year are considered, with required O&M dollars adjusted accordingly.

Q. What budget improvements has the Company made since the 2016 Rate Case?

A. Company witness Mr. Rostollan discusses this issue in detail in his Direct Testimony. However, the largest change for Transmission and Distribution relates to refining our data validation practices. As a Company, we review budget information by FERC Account rather than the historic practice of primarily focusing on work areas and cost types. During the Company's 2016 Rate Case, the Company identified that, as functions shift between work areas or leadership, the departmental view does not provide effective trend data. Additionally, while the Company had a good history of budgeting by cost type, not all work areas were correctly estimating financial impacts to individual FERC accounts within a cost type to the level of detail we now employ. The Company has since placed significant emphasis on FERC Account budgeting and data validation, acknowledging that core functions will retain the same FERC Accounts regardless of the Company reporting structure.

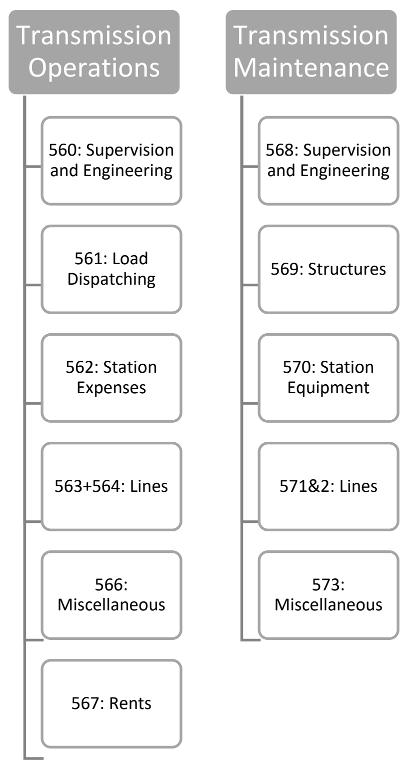
Q. Please describe the key functions within the Transmission organization that are included in the annual Transmission O&M Budget.

A. The Transmission O&M budget includes costs associated with the reliability-centered operation and maintenance of our transmission system. This includes: performing routine inspections; engineering, planning, and performing maintenance activities and emergency repairs for overhead lines, substations, and communication sites; maintaining the overhead line right-of-way through vegetation management; performing system studies; operating the transmission system in real time; and maintaining compliance with NERC reliability standards and FERC standards of conduct.

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

A. Figure 1 provides the FERC Accounts included as major Transmission 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, I discuss it separately from the other FERC O&M Accounts for the Transmission work area. FERC Account 565 is discussed in Section IV.B below.

Q. What is the 2022 test year budget for major Transmission O&M expenses?

A. Table 3 shows total Company actual and budgeted expenses from 2017 through 2020, 2021 projected year expenses, and test year 2022 expenses. We have budgeted $24.8 million Total Company ($20.3 million MN Jurisdictional) in 2022, which is an increase of $2.9 million Total Company ($2.1 million MN Jurisdictional) from 2020 actual expenses. This increase is primarily due to increased labor allocations in the following: Station Equipment, Load Dispatch and Line; increased contract expenses for Load Dispatch and Lines; and expenses associated with anticipated upgrades of leased transmission lines and substation equipment owned by Superior Water Light and Power ("SWL&P"), 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)

Year	2017		2018		2019		2020	
Account	Budget	Actuals	Budget	Actuals	Budget	Actuals	Budget	Actuals
560	4.3M	2.4M	2.7M	2.1M	1.4M	1.9M	1.9M	2.3M
561	8.2M	8.6M	9.7M	8.8M	6.4M	7.6M	8.4M	7.6M
562		0.1M	0.1M	0.2M	0.0M	0.1M	0.2M	0.1M
566	0.8M	1.1M	1.1M	1.4M	0.9M	0.8M	0.7M	0.6M
567	1.8M	1.8M	1.8M	1.9M	1.9M	2.1M	3.5M	2.4M
568		0.0M		0.0M	0.0M	0.0M	0.0M	0.0M
569	2.7M	2.7M	2.3M	1.8M	2.2M	1.7M	1.7M	2.0M
570	3.0M	3.4M	4.7M	3.6M	4.2M	3.5M	3.4M	3.2M
571	3.6M	2.9M	2.7M	2.2M	2.9M	3.9M	3.6M	3.7M
573	0.1M	0.1M		0.1M	0.0M	0.0M	0.1M	0.0M
Total	**24.5M**	**23.0M**	**25.1M**	**22.0M**	**20.0M**	**21.6M**	**23.4M**	**21.9M**

Projected	
Account	2021
560	2.5M
561	8.0M
562	0.1M
566	0.7M
567	2.6M
568	0.0M
569	2.3M
570	3.8M
571	4.8M
573	0.0M
Total	**24.8M**

Unadjusted Test Year	
Account	2022
560	2.8M
561	8.5M
562	0.1M
566	0.7M
567	2.6M
568	0.0M
569	2.0M
570	3.9M
571	4.3M
Total	**24.8M**

Amounts may not total due to rounding.

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

Year	2017		2018		2019		2020	
Account	Budget	Actuals	Budget	Actuals	Budget	Actuals	Budget	Actuals
560	3.5M	1.9M	2.3M	1.7M	1.2M	1.6M	1.6M	1.9M
561	6.8M	7.1M	8.1M	7.4M	5.4M	6.5M	6.9M	6.3M
562		0.1M	0.1M	0.2M	0.0M	0.1M	0.1M	0.1M
566	0.7M	0.9M	0.9M	1.2M	0.7M	0.7M	0.6M	0.5M
567	1.5M	1.5M	1.5M	1.6M	1.6M	1.7M	2.9M	2.0M
568		0.0M		0.0M	0.0M	0.0M	0.0M	0.0M
569	2.3M	2.2M	1.9M	1.5M	1.9M	1.5M	1.4M	1.7M
570	2.5M	2.8M	4.0M	3.0M	3.6M	3.0M	2.8M	2.7M
571	2.9M	2.4M	2.3M	1.9M	2.5M	3.3M	3.0M	3.0M
573	0.1M	0.1M		0.0M	0.0M	0.0M	0.0M	0.0M
Total	**20.2M**	**19.0M**	**21.1M**	**18.4M**	**17.1M**	**18.4M**	**19.5M**	**18.2M**

Projected	
Account	2021
560	2.1M
561	6.6M
562	0.1M
566	0.6M
567	2.1M
568	0.0M
569	1.9M
570	3.2M
571	4.0M
573	0.0M
Total	**20.5M**

Unadjusted Test Year	
Account	2022
560	2.3M
561	7.0M
562	0.1M
566	0.6M
567	2.1M
568	0.0M
569	1.6M
570	3.2M
571	3.5M
Total	**20.3M**

Amounts may not total due to rounding.

Q. Please describe the costs in Account 567 Rents.

A. Account 567 is for Rents and includes a lease expense paid to SWL&P 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 SWL&P. 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 SWL&P transmission system assets. The Company has included $2.6 million Total Company ($2.1 million MN Jurisdictional) in the 2022 test year, reflecting capital additions by SWL&P and the calculation methodology included in the TALA.

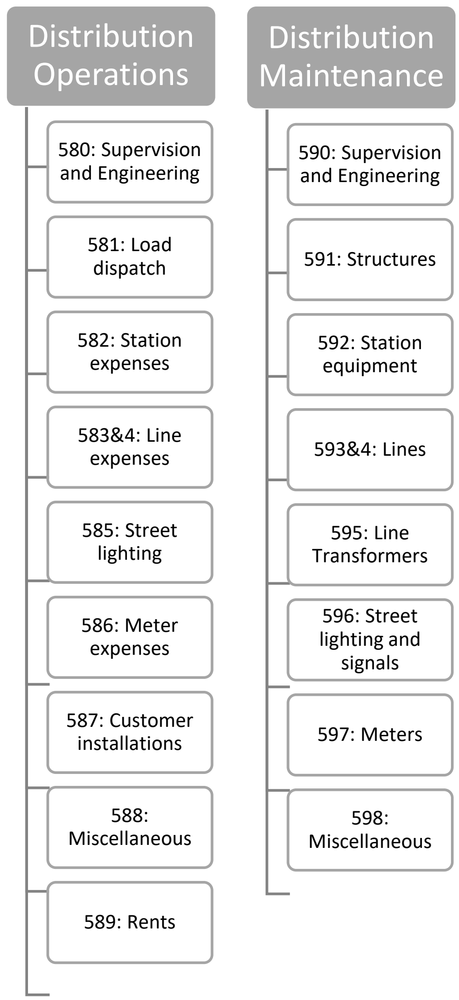
Q. Please describe the key functions within the Distribution work area that are included in the annual Distribution O&M Budget.

A. The Distribution O&M budget includes costs associated with the reliability-centered O&M of our distribution system. This includes: performing routine inspections and audits on our assets such as ground-line poles, transformers, reclosers, switches, and regulators, which also can be audited through our service request system; engineering, planning, and performing maintenance activities and emergency repairs for overhead and underground lines, substations, and customer connections; maintaining the overhead line right-of-way through vegetation management; performing system reliability studies and reporting; installing, testing, maintaining, and reading customer meters; and responding to the changing energy landscape through grid modernization efforts and distributed generation interconnections.

Q. What FERC Accounts are included as major distribution expenses by FERC Account?

A. Figure 2 provides the FERC Accounts included as major distribution expenses.

Figure 2. Distribution FERC Accounts



Q. What is the 2022 test year budget for Distribution O&M expenses?

A. Table 5 shows total Company Distribution actual and budgeted expenses from 2017 through 2020, 2021 projected year expenses, and test year 2022 expenses. We have budgeted $28.6 million Total Company ($27.1 million MN Jurisdictional) in 2022, which is an increase of $8.4 million Total Company ($8.1 million MN Jurisdictional) from 2020 actual expenses. This increase from 2020 actuals to the 2022 test year is primarily driven by the increased vegetation management and meter expenses and the inclusion of storm-related expenses. Table 6 provides these amounts at the Minnesota Jurisdictional level.

Table 5. Distribution Budget and Actual Expenses by FERC Account (Total Company)

Year	2017		2018		2019		2020	
Account	Budget	Actuals	Budget	Actuals	Budget	Actuals	Budget	Actuals
580	1.4M	1.1M	1.2M	1.1M	0.6M	0.9M	1.1M	0.7M
581		0.7M	0.8M	0.3M	0.7M	0.8M	0.8M	0.6M
582		0.0M		0.0M	0.0M	0.0M	0.0M	0.0M
583	0.2M	0.2M	0.2M	0.2M	0.2M	0.2M	0.3M	0.2M
584	0.0M	0.1M	0.0M	0.1M	0.1M	0.1M	0.1M	0.1M
585	0.2M	0.1M	0.2M	0.1M	0.2M	0.2M	0.1M	0.1M
586	1.1M	0.3M	0.0M	0.3M	0.0M	0.4M	0.3M	-0.8M
588	8.1M	7.0M	7.5M	5.4M	6.8M	5.8M	6.6M	4.9M
589		0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M
590	0.8M	0.7M	0.7M	0.7M	0.3M	0.8M	0.8M	0.8M
592		0.1M		0.0M		0.0M	0.1M	0.0M
593	11.0M	12.5M	8.8M	9.4M	9.4M	8.9M	10.9M	10.9M
594	1.3M	1.6M	1.8M	1.7M	1.6M	1.6M	1.6M	1.7M
596		0.0M		0.0M	0.0M	0.0M	0.0M	0.0M
597	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
598	1.3M	0.9M	0.9M	0.8M	0.7M	0.6M	0.9M	0.8M
Total	**25.3M**	**25.6M**	**22.3M**	**20.2M**	**20.6M**	**20.2M**	**23.8M**	**20.2M**

Projected	
Account	2021
580	1.0M
581	0.6M
582	0.0M
583	0.3M
584	0.1M
585	0.1M
586	-0.8M
588	6.6M
589	0.1M
590	0.8M
592	0.1M
593	13.7M
594	1.6M
596	0.0M
597	0.0M
598	0.7M
Total	**24.9M**

Unadjusted Test Year	
Account	2022
580	1.0M
581	0.6M
582	0.0M
583	0.2M
584	0.1M
585	0.1M
586	1.6M
588	6.4M
589	0.1M
590	0.9M
592	0.1M
593	14.9M
594	1.7M
596	0.0M
597	0.0M
598	0.9M
Total	**28.6M**

Amounts may not total due to rounding.

Table 6. Distribution Budget and Actual Expenses by FERC Account (MN Jurisdictional)

Year	2017		2018		2019		2020		Projected	Unadjusted Test Year
Account	Budget	Actuals	Budget	Actuals	Budget	Actuals	Budget	Actuals	2021	2022
580	1.4M	1.1M	1.1M	1.0M	0.5M	0.9M	1.0M	0.7M	1.0M	0.9M
581		0.7M	0.8M	0.3M	0.6M	0.7M	0.8M	0.5M	0.5M	0.6M
582		0.0M		0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
583	0.2M	0.2M	0.2M	0.1M	0.2M	0.2M	0.2M	0.2M	0.2M	0.2M
584	0.0M	0.1M	0.0M	0.1M	0.1M	0.1M	0.0M	0.1M	0.1M	0.1M
585	0.2M	0.1M	0.2M	0.1M	0.2M	0.2M	0.1M	0.1M	0.1M	0.1M
586	1.1M	0.3M	0.0M	0.3M	0.0M	0.4M	0.3M	-0.8M	-0.8M	1.6M
588	8.1M	7.0M	7.2M	5.2M	6.5M	5.5M	6.2M	4.6M	6.2M	6.1M
589		0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M
590	0.8M	0.7M	0.7M	0.7M	0.3M	0.8M	0.7M	0.8M	0.7M	0.8M
592		0.1M		0.0M		0.0M	0.1M	0.0M	0.1M	0.1M
593	11.0M	12.4M	8.4M	9.0M	9.0M	8.5M	10.3M	10.3M	12.9M	14.1M
594	1.3M	1.6M	1.7M	1.6M	1.5M	1.5M	1.5M	1.6M	1.5M	1.6M
596		0.0M		0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
597	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
598	1.3M	0.9M	0.8M	0.8M	0.7M	0.6M	0.9M	0.8M	0.7M	0.9M
Total	**25.2M**	**25.5M**	**21.3M**	**19.3M**	**19.8M**	**19.4M**	**22.4M**	**19.0M**	**23.5M**	**27.1M**

Amounts may not total due to rounding.

Q Why has account 586 increased by $2.4 million Total Company ($2.4 million MN Jurisdictional) from 2020?

A. Account 586 is Meter Expenses and includes costs associated with installing, testing, maintaining, and reading customer meters. This account has seen historical low O&M costs during a multi-year (capital) deployment of AMI meters throughout the Company's service territory. The completion of the AMI capital meter additions has returned this account to normal operations and provided a more representative outlook for Meter Expenses. AMI meter deployment is discussed in further detail in Section V.C.1 of my testimony.

Q Why has account 588 increased by $1.5 million Total Company ($1.5 million MN Jurisdictional) from 2020?

A. Account 588 is Miscellaneous Distribution Expenses and includes: costs associated with internal and external labor costs to prepare and maintain records, maps, and prints; janitorial work at distribution office buildings including snow removal, cutting grass, etc.; and communication services, building service expenses, and miscellaneous office supplies not accounted for in other FERC Accounts. The increase in this account from

2020 actuals to the 2022 test year is primarily driven by an increase in the allocation of internal labor and associated vehicle use expenses undertaken to complete the activities listed above.

Q Why has account 593 increased by $4.0 million Total Company ($3.8 million MN Jurisdictional) from 2020?

A. Account 593 is Maintenance of Overhead Lines and includes costs associated with planned and unplanned overhead line maintenance as well as vegetation management within the overhead line right-of-ways. The increase in this account includes internal labor expenses, a five-year average budget for unpredictable storm-related maintenance, and increased vegetation management expenses. Storm and Vegetation Management and their respective budgets are discussed in further detail later in my testimony.

B. Third-Party Transmission Revenues and Expenses

Q. What is the purpose of this section of your testimony?

A. I am including this section of my Direct Testimony to provide a baseline understanding of the Company's third-party transmission revenue and expenses.

1. Overview of the Transmission System 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, Hibbing, 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, and municipal utilities) have worked together for many years to develop a transmission network that will serve our respective native load customers. 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 our customers by providing the transmission infrastructure needed to serve our 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 shared.

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.

2. Third-Party Transmission Expenses and Revenues

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. 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 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. All 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 arrangement developed to compensate Minnesota Power and Great River Energy for facilities in the Minnesota Power pricing zone consistent with the MISO Transmission Owners agreement.

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. Please describe the transmission third-party expenses and wholesale revenues affecting the 2022 test year.

A. The Minnesota Power system is operated as an integrated system and is treated as one under the relevant provisions of the MISO Tariff. Using third-party transmission is necessary to serve Minnesota Power system loads, including Minnesota Power retail native loads in Minnesota, and thus the costs should be included in rates. However, these costs are offset by various transmission service revenues, thereby reducing total costs to Minnesota Power customers. MP Exhibit ___ (Gunderson), Direct Schedule 4 provides the detailed third-party transmission revenues and expenses, including revenues and expenses shared through the TCR Rider, for the 2017, 2018, 2019, and 2020 actuals; 2021 projected year; and 2022 test year in Total Company and MN Jurisdictional amounts.

Q. What are the third-party transmission revenues and expenses applicable to base rates in the 2022 test year?

A. As shown in MP Exhibit ___ (Gunderson), Direct Schedule 4, the 2022 test year base rates include $57.0 million Total Company ($47.0 million MN Jurisdictional) of transmission revenues and $34.2 million Total Company ($28.1 million MN Jurisdictional) of transmission expenses, net of costs recovered, and revenues shared through the TCR Rider.

Q. How does the 2022 test year compare to the 2020 results for the amounts applicable to base rates?

A. The 2022 test year third-party transmission revenues exceed expenses applicable to base rates by $22.8 million Total Company ($18.9 million MN Jurisdictional) whereas the 2020 actual third-party transmission revenues exceeded expenses applicable to base rates by $16.4 million Total Company ($13.7 million MN Jurisdictional).

Q. What are the main drivers impacting the differences between 2020 actuals and the 2022 test year budget third-party transmission revenues and expenses applicable to base rates?

A. The 2022 test year third-party transmission revenues are $6.9 million Total Company ($5.3 million MN Jurisdictional) higher than 2020 actuals. The 2022 test year third-party transmission expenses are only $0.5 million Total Company ($0.1 million MN Jurisdictional) higher than 2020 actuals.

The largest revenue increase between 2020 actuals and the 2022 test year budget is due to the inclusion of a monthly "Must Take Fee" which was negotiated as part of the Power Purchase Agreement and an Energy Exchange Agreement with Manitoba Hydro for the purchase of 133 MW of Energy. This Must Take Fee commenced in 2020 coincident with the GNTL Project being placed into service. The Power Purchase Agreement is discussed in the Direct Testimony of Company witness Julie I. Pierce. The 2022 test year revenue for the Must Take Fee is $8.0 million Total Company ($6.5 million MN Jurisdictional) higher than 2020 actuals.

Q. Do the 2022 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 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 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. 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. 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 7.

Table 7. 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 2: Reactive Supply and Voltage Control from Generation or Other Sources	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
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)	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 purposes of the JPZ Agreement with Great River Energy.

Q. Please describe the 2022 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 our 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 $2.8 million Total Company. The annual payment cap was met in each of the years 2017 through 2019. The MN Jurisdictional amounts for these years were $2.3 million (2017), $2.3 million (2018), and $2.4 million (2019). The 2022 test year includes an expected payment of $1.3 million Total Company ($1.0 MN Jurisdictional) to Great River Energy due to a higher share of the overall investment of transmission assets within the zone compared to 2020 and 2021;
- *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) and Reactive Supply and Voltage Control (Schedule 2) 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. What has historically been one of the larger revenue contributors to the third-party transmission revenues?

A. In the past, one of the most significant revenue sources is from a number of Point-to-Point Transmission Service Requests ("TSRs") that could be directed for delivery or "sunk" into the Minnesota Power MISO pricing zone. The TSRs are reflected in FERC Account 456 in MP Exhibit ___ (Gunderson), Direct Schedule 4. The financial impact of these particular TSRs can contribute millions of dollars of third-party transmission revenue. These TSRs do not serve Minnesota Power load nor are they controlled by the Company. These TSRs could either be directed to the Minnesota Power pricing zone or to a different MISO pricing zone on an annual basis. TSRs are charged monthly based on individual start and stop dates of each TSR.

Q. How is Point-to-Point TSR revenue distributed in MISO?

A. In MISO, Point-to-Point transmission revenues are distributed among the pricing zones as follows: (i) 50 percent of such revenues shall be distributed in proportion to transmission investment (calculated each month based on the relevant proportion of transmission investment reflected in the then applicable rates determined by the formula in Attachment O to the Tariff); and (ii) 50 percent of such revenues shall be shared based upon power flows.

Q. Are these TSRs stable revenue sources, such that the company can count on this revenue in the future?

A. No. These TSRs provide welcome third-party transmission revenue but the revenue is not within Minnesota Power's control. If these TSRs were delivered to a different pricing zone, the revenue received by Minnesota Power through the MISO revenue distribution formula for TSRs of this nature would be significantly less. Currently Minnesota Power makes up only 1.73 percent of the transmission investment in MISO, so, without the power flow component of revenue distribution calculation for these TSRs, Minnesota Power receives minimal revenue for Point-to-Point TSRs.

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. The Schedule 2 rate is based on stated revenue requirements,[16] updated only when the existing revenue requirements are no longer viable. This Schedule was most recently updated (FERC Docket ER19-283) to appropriately reflect the closure of BEC Units 1 and 2 as well as account for additional generator changes since the last Schedule 2 update in 1996 (ER96-1580). Revenue requirements for Schedules 1, 7, 8, 9, 26, and 45 are updated every year through Schedule 1 and Attachments O, GG, 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. How is the 2020 Schedule 1 and Attachments O, GG, and ZZ true-up of revenue and load included in the 2022 test year budget?

A. Minnesota Power monitors the major drivers of the Attachments O, GG, and ZZ revenue requirements throughout the year for which they are projected. At the end of 2020, Minnesota Power made an accrual entry related to the 2020 revenue requirements, as a regulatory liability. This accrual will be reversed during 2022, when the true-up is applied to revenue requirements in Attachments O, GG, and ZZ. This process ensures the Company is reporting revenues in the year for which they are earned. It also ensures the rate filings are not impacted by prior year events, thereby eliminating any retroactive ratemaking. Similarly, an accrual will be made during 2021 for the anticipated 2021 true-up of MISO Schedule 1 and MISO Attachments O, GG, and ZZ. This entry will be reversed in 2023, when the actual true-up for 2021 revenue requirements and load are processed with MISO.

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[16] Note that the phrase "revenue requirements" in this section does not refer to the "revenue requirements" to be established as part of this rate case. Instead "revenue requirements" used in this section and in the context of third-party transmission revenues and expenses refers to transmission system related revenue requirements for transmission rate calculation/determination purposes.

Q. Has Minnesota Power reasonably and prudently developed its third-party transmission revenues and expenses budget for the 2022 test year?

A. Yes. The Company has taken into account all the details available to it, known trends, and system expectations to carefully, thoughtfully, and reasonably develop the third-party transmission revenues and expenses for the 2022 test year.

3. Pending FERC Proceeding

Q. Please explain the relevance of the pending FERC proceedings in FERC dockets EL14-12-000 and EL15-45-000.

A. In November 2013, a group of customers filed a complaint at FERC against MISO transmission owners, including the Minnesota Power System (Docket EL14-12-000). The complaint argued for a reduction in the return on equity ("ROE") in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE incentive adders.

After a series of proceedings on May 21, 2020, FERC approved a ROE of 10.02 percent, plus a 50-basis point ROE incentive adder. This approved ROE value is utilized in the overall calculation of Minnesota Power's wholesale transmission revenue requirements through Attachments O, GG, and ZZ.

An additional complaint was filed in February 2015 proposing to reduce the MISO region ROE to 8.67 percent (Docket EL 15-45-000). FERC has established a refund effective date of February 12, 2015 for this second complaint and initiated hearing procedures. Hearings were held in February 2016, and an initial Administrative Law Judge decision of 9.7 percent was issued on June 30, 2016.

While the above referenced dockets are still working their way through the appellate process, MISO along with the MISO Transmission Owners, has been working through the ROE resettlement with an estimated completion date of June 30, 2022.

Q. What ROE was assumed for purposes of this case?

A. The 2022 test year budget for wholesale transmission revenue and third party transmission expense was prepared based on the currently authorized FERC ROE of 10.02 percent plus the 50 basis point adder for a total ROE of 10.52 percent.

Q. Why was this ROE selected?

A. Establishment of a just and reasonable ROE is the responsibility of FERC. FERC issued an order authorizing an ROE of 10.02 percent and separately authorized the 50 basis point adder, resulting in a total ROE of 10.52 percent. Minnesota Power complies with these FERC authorizations by including the resulting total ROE amount in its wholesale transmission revenue requirement.

C. <u>Storm Response and Restoration</u>

Q. How are storm response and restoration costs incorporated into the 2022 test year budget?

A. As previously discussed, FERC Account 593 includes both planned and unplanned maintenance of overhead lines. Unplanned maintenance is considered "trouble" work and includes responding to outage events that can be caused by multiple sources, including animals, storms, people, etc. Some of these outage events are caused by storms, which are unpredictable in both their timing and their associated impact. Depending on the nature of the storm damage, the restoration could result in O&M expenses or capital additions. Due to the unpredictability of trouble work, the budget for all trouble work is based upon a five-year average of Overtime dollars, Contract Services, and Purchased Materials in Account 593 from our Line Operations work area.

Q. What is the 2022 test year Budget for "trouble" work included in Overhead Line Maintenance?

A. The 2022 test year budget associated with "trouble" work is $2.3 million Total Company ($2.2 million MN Jurisdictional). It is based upon a five-year average of spend for FERC Account 593 (Maintenance of Overhead Lines). The budget averages spend for

Overtime dollars, Contract Services, and Purchased Materials in our Line Operations department.

Q. How is Minnesota Power changing the way it reports on O&M costs associated with storm response in this rate case?

A. In the 2016 Rate Case, the Company attempted to illustrate the impact of storm related costs on operating expenses in a manner that was not easily understood by stakeholders. In this current rate case, for increased clarity and understanding, the Company is requesting recovery of all costs associated with FERC Account 593 Maintenance of Overhead Lines, which include a five-year average of costs related to storm recovery and restoration in the budget. While averaging is not traditionally the most appropriate way to set Company budgets, Minnesota Power believes that averaging is the most prudent and reasonable basis upon which to budget for unpredictable storm expenses because the proposed five-year average takes into account both high-year and low-year expenses for this response.

Q. Does Minnesota Power design and build its transmission and distribution systems to withstand storms?

A. To the greatest extent practicable, yes, we do. The reliable, safe, and efficient delivery of electricity to our customers is of the utmost importance to the Company and without our transmission and distribution infrastructure, we are unable to provide that service. Minnesota Power designs and builds our system to sustain various weather conditions, including high winds, ice, snow, and extreme heat and cold. Extreme weather conditions, however, are beyond our control and, at times, do impact service to customers. In those instances, the Company responds as expeditiously as possible, while also ensuring the continued safety of personnel and the public. The capital projects described previously in my Direct testimony help to ensure not only the reliability of our system, but its increasing resilience in the face of more extreme weather events.

Q. Please explain how Minnesota Power has previously handled the financial impact of storm response and restoration costs.

A. Minnesota Power has not previously included storm response costs in base rates. The Company previously sought, but was not granted, deferred accounting treatment of costs incurred during major storms. As a result, the Company was unable to recover the costs of the major storm events that occurred during 2015 and 2016. The Company currently uses a five-year rolling average of expenses as described above to develop its budget for all "trouble" work.

Q. Does Minnesota Power complete all storm response and restoration work using its own line workers?

A. For over 17 years, until the summers of 2015 and 2016, Minnesota Power was able to successfully complete all storm response and restoration work using its own line workers. In 2015 and 2016, intense storms rolled through our service territory and Minnesota Power had to request mutual assistance from its other utility partners to ensure timely restoration of electric service to Minnesota Power customers.

Minnesota Power maintains mutual assistance agreements with multiple electric utilities and contractors. Under these agreements, utilities can obtain the assistance of other utilities' employees when experiencing widespread outages. This means that Minnesota Power will respond to other utilities' requests, when it is able to do so and, when Minnesota Power and its customers need additional response assistance, those utilities respond as their resources allow them to assist in northern Minnesota.

Q Does Minnesota Power provide mutual assistance to other utilities?

A. Yes. For example, in 2017, Minnesota Power provided mutual assistance to assist the southern United States and Puerto Rico to restore electric service after the devastating effects of hurricanes Irma and Maria. Minnesota Power also assisted Manitoba Hydro in restoring power after experiencing heavy snow and high winds in a slow-moving storm in 2019. In 2020, crews responded to Illinois and Iowa to restore power after violent summer storms caused widespread damage to the grid. Minnesota Power crews have also joined utility hurricane responses six times in the past 15 years, including responding to needs in Florida, Maryland, New Jersey, and in Puerto Rico from late 2017 into early 2018 after Hurricanes Irma and Maria.

Q. When Minnesota Power provides mutual assistance, how are costs recovered?

A. Costs and reimbursements associated with mutual assistance provided by Minnesota Power to other utilities are captured in the non-regulated side of our business and therefore have no impact on our customers. When the Company sends crews to assist in outage restoration efforts for other utilities, Minnesota Power creates unique work orders to record all actual direct costs — including labor, support, overtime, transportation, meals, lodging, etc. — that are incurred by our line workers and any support personnel assisting the line workers. Minnesota Power records all of the charges for time, equipment, and expenses against that work order from the time our line workers depart from their mobilization site until they arrive back to the mobilization site. Minnesota Power then includes corporate overheads in final bills to the utility that our line workers and personnel were assisting. This industry practice is followed by other investor owned utilities when they send line workers to assist us in any widespread storm response and restoration effort when Minnesota Power requests mutual assistance. When Minnesota Power receives mutual assistance, our customers receive a direct benefit of faster restoration of service and, therefore, those costs paid to the responding utilities are covered by the regulated side of our business.

D. Vegetation Management

Q. Please describe Minnesota Power's current vegetation management program.

A. The goal of Minnesota Power's vegetation management program is to provide safe and reliable transmission and distribution of electricity by controlling growth of non-compatible species and encouraging the growth of compatible species under, on, or adjacent to its transmission and distribution facilities, rights-of-way, or easements. Non-compatible species are defined as those trees that mature at a height that allows them to grow into the electric facilities and cause outages and create safety concerns. This is accomplished through adherence to Integrated Vegetation Management principles, which include mechanical, chemical, and cultural methods of control. The vegetation management program minimizes tree-related interruptions, adheres to NERC FAC-003, American National Standards Institute ("ANSI") Z133.1 and A300 standards, and follows National Electrical Safety Code Section 218. Other goals and objectives include: positive customer relations, adherence to all regulatory and legal requirements, continuous environmental improvement, and support of public and worker safety through maintenance of adequate clearances between conductors and vegetation. Minnesota Power also maintains a link on our webpage to the "Right Tree" brochure. This brochure is intended to assist our customers in selecting the type and species of vegetation that are compatible near power lines.

Minnesota Power employs a vegetation management program that relies on trained and educated foresters and arborists. Ongoing monitoring of contractor timesheets/invoices by Minnesota Power Vegetation Management staff assures that Company resources are being utilized in the most cost-effective manner. Minnesota Power also has regular evaluation meetings with our contractor to ensure compliance with our agreement. Various vegetation management techniques and tools are employed to get the best value from resources allocated.

The Vegetation Management O&M budget allows Minnesota Power to trim, remove, mow, and apply herbicide to control the growth of vegetation along transmission and distribution power line rights-of-way. Vegetation is also controlled in and around substations, dikes, dams, and hydro facilities as needed to protect the electrical system from vegetation related interactions. Minnesota Power also responds to customer requests to remove or trim vegetation that is interfering or threatening Company facilities.

Minnesota Power monitors its progress through the analysis of tree-related outage data collected, percent completion of planned work, and regular site visits. Minnesota Power utilizes vegetation management methods that are the most cost effective to ensure the best use of limited resources. The Integrated Vegetation Management plan is executed by trained and educated foresters.

Q. Does Minnesota Power employ a cyclical vegetation management program?

A. Yes. Minnesota Power maintains a Vegetation Management plan that addresses routine vegetation management on distribution lines every six years and on transmission lines every seven years.

Q. Is this approach to vegetation management used among other electric utilities?

A. Yes. Cyclical vegetation management is the industry standard. Maintaining cycles is critical to effectively managing cost. It takes longer and creates more biomass to trim and remove trees once a circuit is off-cycle. Tree workers must take extra precaution to ensure safe work distances are maintained once vegetation has grown between and beyond the conductors. Off-cycle circuits also contribute to an increase in outages or momentary losses of service to our customers, which affects System Average Interruption Duration Index and System Average Interruption Frequency Index.

Q. Please describe any changes made to the program since Minnesota Power's 2016 Rate Case.

A. In 2019, Minnesota Power began using mobile workforce solutions to aid the vegetation department in fieldwork. This includes electronic GIS mapping, a quick capture application for aerial patrols, and an electronic application that allows Minnesota Power field employees to report vegetation issues. All of these applications have resulted in increased productivity, faster data gathering, and most importantly, achieving accurate data points for work identified. These changes have been incorporated into our budgeting process as well. The Company continues to explore other electronic alternatives and new technology to aid its vegetation management work.

Q. Describe the processes Minnesota Power has historically had in place to ensure the cost of the vegetation management program is reasonable.

A. Minnesota Power utilizes a contracted workforce, which allows the company the flexibility to seek out, through a competitive bid process, the most cost-effective, skilled workforce to provide vegetation management services. The most cost-effective vegetation management technique is to target immature trees for removal and control. It is generally less expensive to treat with herbicide or remove immature trees than to trim them repeatedly. By removing a tree, the cost to prune that tree during the next cycle is eliminated and for every cycle thereafter. Some mature trees can be removed as well due to declining health issues, proximity to facilities, rate of regrowth, or due to the negative impression left by unsightly trees near the power lines. It is more expensive to remove mature trees, but that may ultimately be the best option. The up-front costs of clear rights-of-way and easements lead to reduced cost of upgrades and reduced time for storm restoration events and promote safe operating conditions. Herbicides are tools, which also save money in the long run by eliminating trees and brush from the system.

Minnesota Power contracts vegetation work on a circuit/line basis for a period of one year. This period of time allows Minnesota Power to account for electrical changes in circuits/lines that are made to improve reliability. Awarding contracts annually provides flexibility to review and address contractor availability, performance, and cost management. Minnesota Power contracts for the following year's vegetation maintenance approximately six months in advance to assure it has the contract resources to complete its vegetation plan.

Minnesota Power has historically relied on a fixed bid (i.e., lump sum) contracting process for distribution circuit maintenance. However, this method of bidding is based on tree trimming and does not account for a large number of tree removals because bidders do not know at the time of bid preparation, which customers will be accepting of tree removal versus a tree trim. Under this approach, there is no financial incentive for contractors in a fixed bid contract to obtain removals, which are generally more costly to perform. Over time, the Company has seen a decline in tree removals on the Distribution system and attributed this to the lack of incentive in a fixed bid contract.

Q. How is the scope of vegetation management currently communicated to customers?

A. In the Company's Rate Book, Section VI, pages 3.7 and 4.5, the Company explains that the maintenance of rights-of-way are necessary for construction, operation, and maintenance. The Company thinks it would be beneficial to make changes to the relevant electric service regulations in the Rate Book.

Q. Why is Minnesota Power proposing a change to the electric service regulations?

A. Minnesota Power is proposing a change to language in electric service regulations to capture and broaden the full scope of vegetation management. Upon review of the Rate Book for purposes of preparing this case, Minnesota Power identified that only "tree trimming" is currently mentioned. The use of "vegetation management" captures Minnesota Power's broader approach to eliminating conflicts between vegetation and electrical facilities. Proposed revisions are included with this filing at Volume 3, Final Rate Tariff Sheets.

Q. Has Minnesota Power made any changes to its vegetation management program to address these concerns?

A. Yes. In 2021, Minnesota Power implemented a Time and Material ("T&M") pilot on distribution circuits to increase the number of tree removals and lower vegetation related outages. The Company allocated distribution circuits based on past contractor performance and the geographic operating areas of five different contractors. Minnesota Power is measuring the effectiveness of this pilot by number of tree removals and overall cost of the line. With the data available at this time, Minnesota Power has experienced more tree removals under the T&M pilot than in the past under fixed bid contracting method. These removals mean less maintenance trimming in the years ahead along these circuits. Additionally, since implementing these changes, Minnesota

Power has received fewer customer complaints since work planners are spending more time and effort with customers to explain the need for trimming and removal of trees.

These actions have led to better quality of finished product, better clearances from vegetation to electrical system, and removal of long-term trees that were only trimmed in the past. Better quality and clearances will lead to increased reliability on the Minnesota Power system and long-term cost management as future tree trimming is also eliminated. Transmission vegetation maintenance contracting strategy has remained the same as the past and was competitively bid and awarded on a fixed price.

Q. Why is Minnesota Power proposing an increase in vegetation management spending?

A. Minnesota Power's 2022 Vegetation Management budget for both transmission and distribution is $9.6 million Total Company ($8.8 million MN Jurisdictional). This budget amount is an increase over the 2021 projected year by $0.2 million Total Company ($0.2 MN Jurisdictional) and over the 2020 actuals by $2.7 million Total Company ($2.5 MN Jurisdictional). The increase is needed to address higher vegetation related cost increases in labor, equipment, chemicals, and off-cycle growth.

Similar to the current experiences in other industries, Minnesota Power is experiencing the effects of a labor shortage in the tree care industry. Additionally, some contractors lack trained workers to operate specialized equipment, and there are not enough tree workers to respond to time sensitive projects. The competition between various industries (e.g., pipeline, utilities, and municipal) for the specialized type of tree care these contractors provide has led to higher costs. Because available labor is difficult to find at this time, it is also difficult to draw new employees into the field in a demanding, physical occupation like Vegetation Management. The Company anticipates continued increased spending will be needed in the future to address these costs, labor constraints, and management of off-cycle circuits. A recent indicator of additional expected increases to obtain skilled labor in Northern Minnesota was a wage increase back payment notification from a few of the Contractors after the ratification of their union contract in mid-2021.

Finally, a number of substations and other electrical systems have been added to improve reliability following the idling, retirement, and re-missioning of baseload coal generation in the region and also to facilitate delivery of variable renewable energy, which has led to more facilities to maintain.

Q. Please describe the budget/actual spending for Minnesota Power's current vegetation management program.

A. Minnesota Power is responsible for maintenance on approximately 1,321 miles of lines 200 kV and above under the NERC FAC-003 standard. These lines are monitored annually and corrective maintenance is performed as needed to maintain compliance. Routine vegetation maintenance occurs on a rotating seven-year cycle. The remaining transmission lines are scheduled for routine vegetation maintenance on a rotating seven-year cycle, but may not receive an annual inspection like those of 200 kV and above.

The total O&M budget for transmission vegetation maintenance in 2022 is $2.0 million Total Company ($1.7 million MN Jurisdictional). The remaining O&M budget for 2022 of $7.6 million Total Company ($7.2 million MN Jurisdictional) is allocated to distribution vegetation maintenance, customer requests, and construction or facilities replacement vegetation work. Currently there are distribution circuits that are behind the six-year maintenance cycle as reported in the last Safety, Reliability and Service Quality Standards ("SRSQ") report (Docket No. E015/M-21-230). When circuits fall behind, every effort is made to prioritize the maintenance of these circuits in the following year. Due to industry resource limitations and desire to balance spend year over year, it typically takes a couple of years to get all circuits back into their six-year cycle. As a result, the O&M budget was increased to account for extra clearing and additional vegetation growth being more expensive to clear and maintain.

E. Reliability Compliance

Q. What is the regulatory oversight for transmission system reliability?

A. Maintaining transmission system reliability involves compliance with NERC Reliability Standards. In 2007, FERC granted NERC the legal authority to enforce reliability standards on all transmission owners and operators. NERC delegates its authority to monitor and enforce compliance to Regional Entities established across North America. The Midwest Reliability Organization ("MRO") is the Regional Entity that oversees Minnesota Power's compliance with NERC Reliability Standards. There are roughly 74 NERC Reliability Standards consisting of over 1,000 standard requirements and sub-requirements applicable to Minnesota Power, with at least five new or revised Reliability Standards coming into effect in 2022.

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

A. Minnesota Power's NERC compliance program is designed to achieve safe, reliable 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. Minnesota Power's transparency about potential noncompliance resulted in the MRO's 2017 approval for Minnesota Power to participate in the Self-Logging program, making the company one of approximately 31 registered entities (out of over 200 overseen by the MRO) who are allowed to self-log potential minimal-risk compliance discrepancies. To grant participation in the self-log program, the MRO evaluates an entity's demonstrated effectiveness at identifying noncompliance, assessing the risk posed by noncompliance, and mitigating noncompliance using the principles of a High Reliability Organization, i.e., demonstrating the capacity to anticipate and contain unanticipated problems.

Q. Describe the necessity for heightening cyber and operational security at Minnesota Power.

A. While technology allows for faster response times in maintaining grid integrity and minimized customer disturbance/outages, it also provides a vulnerability to bad actors who would exploit cyber vulnerabilities and create disruptions. Such disruptions could result in outages, damage to grid infrastructure, and/or expose company data. The threat landscape is constantly changing, requiring continuous diligence for both cyber and physical security threats. Due to this heightened risk attributed to cyber and physical access, NERC has mandated Critical Infrastructure Protection ("CIP") Standards to reduce the likelihood and impact of such events.

Q. Describe the challenge of implementing mandated compliance-related activities into existing work practices.

A. NERC CIP Standards evolve frequently to expand the breadth and depth of protection for utility assets. Some of the major revisions and new Standards in recent years include: the July 2016 implementation of Version 5 of NERC CIP Standards which expanded the scope of protections for high- and medium-impact transmission system assets and facilities; the January 2020 implementation of low-impact protections for approximately 80 Minnesota Power substations (i.e., most substations operated at 100 kV or higher voltage) and seven of its generation sites; and the implementation of CIP-014 risk assessments and physical security plans for certain important transmission substations and associated control centers. Each of these implementations presented multiple challenges as Minnesota Power assessed and revised its security measures and work processes/procedures. Conducting system-wide inventories while interpreting the applicability of various standards and requirements — and developing sustainable technical solutions — necessitated that many Company employees expand their knowledge beyond their previous levels of expertise. In addition to ongoing efforts to execute revised work practices for existing assets, the CIP Standards also require periodic re-performance of assessments that determine what facilities and assets are in scope.

A new Supply Chain Risk Management Standard went into effect in October 2020, requiring implementation of supply chain controls for purchases related to high- and medium-impact assets. While these are valuable protections, the new requirements have increased the complexity and time for purchases by adding steps such as vendor cyber-risk assessments and new contractual obligations with vendors.

Q. How has Minnesota Power responded to the new challenges of NERC compliance?

A. Minnesota Power employees with relevant obligations are trained in the skills needed to verify NERC compliance, including attending industry training events where there is an increased focus in research and development towards automation and asset management. Employees use resources available through the Company's membership in the North American Transmission Forum to inform their compliance methods. The Company has procured software tools to track and trend asset performance including test data to enable the ability to predict equipment failures and ensure timely maintenance to lower operational expense and improve system reliability.

With frequently changing and new NERC Standards, Minnesota Power's compliance work has grown to implement the changes, to maintain and support the new systems, to maintain compliance evidence and documentation, and to respond to compliance monitoring and enforcement activities such as audits and self-certifications. From 2015-2020, the Company's average annual O&M labor hours directly related to NERC compliance is over 20,700 hours.

Q. Are there additional NERC compliance impacts beyond those you have already mentioned?

A. Yes. Changes and updates to NERC operational standards have required improvements to tools used for situational awareness and real-time assessments, staff resources to support and maintain the expansion of data and tools, and increased training needs for system operators.

NERC Reliability Standards continue to evolve and develop. This requires continued training, dedication of resources, and ongoing system and process improvements to meet compliance obligations efficiently and effectively.

F. Service Centers

Q. The 2016 Rate Case discussed cost savings related to the sale and closure of company-owned service centers. Have there been any new developments in this area since then?

A. As part of the Company's long-range facility planning process, Minnesota Power conducts a thorough and ongoing analysis of the current use of our service centers. All Transmission and Distribution service centers currently in use are under the scope of this review. Some Service Centers may require either upgrades or remodeling, and some could cease to be Minnesota Power assets moving forward if they become no longer viable for operations. Since the 2016 Rate Case, Minnesota Power sold the Crosby Service Center. Minnesota Power received approval to sell the Crosby Service Center on January 25, 2021 in Docket number E015/PA-20-839 and sold it on March 8, 2021.

Minnesota Power agreed to credit customers for the gain on the sale and for the amounts customers would pay for the revenue requirements associated with the Crosby Service Center during the period following the sale of the property and up until the Company files its next rate case. The associated regulatory liability and its amortization is discussed in the Direct Testimony of Company witness Amanda L. Turner. Additionally, an evaluation of the Park Rapids Service Center revealed that, although the depreciable life of this facility has come due, it remains a viable facility for the Company's operations and there are currently no plans to sell the Park Rapids Service Center. Future investment to maintain the Park Rapids Service Center will be evaluated to ensure prudency and continued viability of this facility.

To expand our long-range facility planning, Minnesota Power is working closely with a consultant to evaluate our key staffing and system need considerations for our service centers.

Q. How does the Company handle service centers that are no longer viable for operation?

A. Where the Company ceases to operate at any given facility moving forward, a thoughtful transition plan is required to ensure that employees are informed of these changes in a timely manner and these assets can be marketed to maximize market value. The Company's operational use of facilities continues to evolve over time. If the required maintenance investments associated with continued ownership are greater than the benefits of the service center, Minnesota Power then will consider options ranging from continued ownership and renting or leasing out unused portions of the Service Center to closure and sale.

G. Purchasing and Procurement Initiatives

Q. What business improvement efforts have been made in purchasing and procurement since the 2016 Rate Case?

A. Minnesota Power utilizes a competitive bidding process for all capital projects and other purchases over $10,000. Minnesota Power procurement professionals manually track savings achieved through the Company's bidding process. When calculating these savings, buyers average the total dollars of quotes within a competitive range, excluding the low bid, then subtract the low bid from the average calculated to get the actual hard dollar savings of the purchase. Total competitive bidding cost savings averages approximately $14 million per year.

Since late 2017, the Purchasing Department has also been working with Minnesota Power's vendors on new payment initiatives to capture additional cost savings. The Company's goal is to encourage as many vendors as possible to switch from check payments to the Automated Clearing House to reduce check printing and processing costs. Additionally, the Company has increased our standard payment terms from Net

30 to Net 60 to improve our cash flow and working capital. The purchasing department continues to work on the development of new initiatives to improve procurement processes and efficiency.

Finally, savings are also achieved through the Sustainable Performance Initiative where buyers partner with Minnesota Power Operations personnel to identify cost savings opportunities. Examples of these include transmission and distribution pole contracts, waste management services, underground cable locating services, and current tool usage and spending. These are typically areas where there are multiple contracts that can be consolidated to one vendor or areas where standardization are likely to reduce costs.

Q. Has the Transmission and Distribution work area undertaken any of these efforts with other Company work areas?

A. Yes. The Purchasing Department also partnered with the tax, inventory, and accounts payable areas to enhance an existing software module already in use within our Enterprise Resource Planning ("ERP") system that allows us to be more accurate when calculating sales tax on purchase orders and invoices. This module works with the purchasing, inventory, and accounts payable modules and requires the user to identify the purchasing category and intended use of the item or service they are requesting. The ERP system then calculates the rates as taxable, non-taxable, or exempt depending on the ship-to location and the state, county, and city tax rules. This enhancement helps us identify when an item or service is tax exempt or non-taxable to avoid paying tax when it is not required, and when an item or service is taxable, the right tax rates are applied.

Q. **How does Minnesota Power's Supply Chain support Diversity, Equity and Inclusion ("DE&I")?**

A. Minnesota Power supports DE&I by partnering with diverse suppliers including minority-owned, women-owned, veteran-owned, LGBT+-owned, small economically disadvantaged businesses, HubZone businesses, and disability-owned businesses so that its suppliers reflect the diversity of the communities it serves. Minnesota Power provides equal access for all qualified businesses, including both direct Tier 1 diverse suppliers and also Tier 2 suppliers that report on diverse spend. Tier 1 suppliers contract directly with Minnesota Power. Tier 2 suppliers indirectly support Minnesota Power by supplying Minnesota Power's Tier 1 suppliers with goods or services that are procured for Minnesota Power. In addition to tracking Tier 1 and Tier 2 spend, the Company also tracks credit card spend with diverse suppliers. The 2022 O&M test year includes an added position as well as funding for outreach and membership in diverse community organizations to support this initiative.

Q. What has Minnesota Power done to effectuate the Minnesota Energy Utility Diversity Stakeholder Group ("EUDG") recommendations to increase supplier diversity?

A. Minnesota Power was a key participant in the EUDG, which authored a report to the Minnesota Legislature in early 2020 outlining recommendations for utilities to increase the diversity in both their workforce and their supply chain. Since issuance of that report, Minnesota Power has implemented every one of the EUDG's recommendations on supplier diversity, including:

- Sharing lists of diverse suppliers with Xcel Energy and CenterPoint Energy;
- The Company has had several meetings with Xcel Energy and CenterPoint Energy around best practices for supplier diversity; attended "lunch and learn" events during summer 2020 co-sponsored by Xcel Energy and the Women's Business Development Center; attended the first annual Minnesota Utility Industry Supplier Diversity Symposium in early November; performed outreach to Enbridge around supplier diversity best practices;
- The Company has attended diverse supplier networking and lunch and learn events sponsored by the Women's Business Development Center; has had virtual meetings with the National Veteran Business Development Council and the North Central Minority Supplier Development Council;
- The Company has added Tier 2 supplier diversity language into high volume materials contracts and is currently in the process of adding Tier 2 supplier diversity language into additional service contracts; and

- The Company solicits information from our credit card provider on diverse supplier spend on a quarterly basis.

V. SYSTEM RELIABILITY AND CUSTOMER SERVICE

A. <u>System Reliability</u>

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

A. Minnesota Power continues to prioritize sound investments in the distribution system to maintain and improve reliability of the essential service we provide, and we are focused on the maintenance and replacement of critical assets as necessary to maintain safe system performance. Further, routine inspection and vegetation management activities on the distribution system lower the cost of operation over the long term and help to mitigate potential reliability issues. The Company annually reports overall system reliability in intricate detail in the SRSQ. In that report, Minnesota Power outlines how the Company continuously strives to provide efficient, reliable service to all customers across a unique service territory in northeastern and central Minnesota.

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

A. Minnesota Power has seen a significant increase in weather related outages since 2016 that have impacted customer reliability. Overall, the total number of outage events resulting in trouble tickets has averaged over 40 percent above historic averages since the last rate case. Besides weather impacts, Minnesota Power has seen significant increases in outages related to human causes (e.g., vehicle incidents and dig-ins) and aging underground and overhead infrastructure. One example of the Company's efforts to improve reliability is the Company's work to strategically underground certain overhead distribution lines.

Q. What is strategic undergrounding and how is Minnesota Power using it to improve reliability?

A. Strategic undergrounding was first initiated in 2020 and will continue with some of the Company's worst performing overhead distribution lines being prioritized for undergrounding. The Company is targeting areas where customers do not allow access to distribution vegetation management, such as tree trimming, and areas where overhead distribution lines are installed cross-country in inaccessible areas with heavy vegetation. The main drivers for strategic distribution undergrounding are reliability improvement, storm resiliency, aging asset replacement, potential O&M vegetation reduction costs, and reductions in trouble costs as reliability improves. Locations are prioritized based on feeder reliability, vegetation costs, accessibility for maintenance, and geology. Industry consultants are also currently being used to help develop a long-term plan that prioritizes distribution undergrounding efforts based on projects that provide the best cost-benefit for our customers. Based on the experiences of other utilities that have implemented similar programs, the Company anticipates several customer benefits including fewer outages, O&M cost savings, enhanced safety, and enhanced reliability.

Q. What is Minnesota Power doing to improve system reliability?

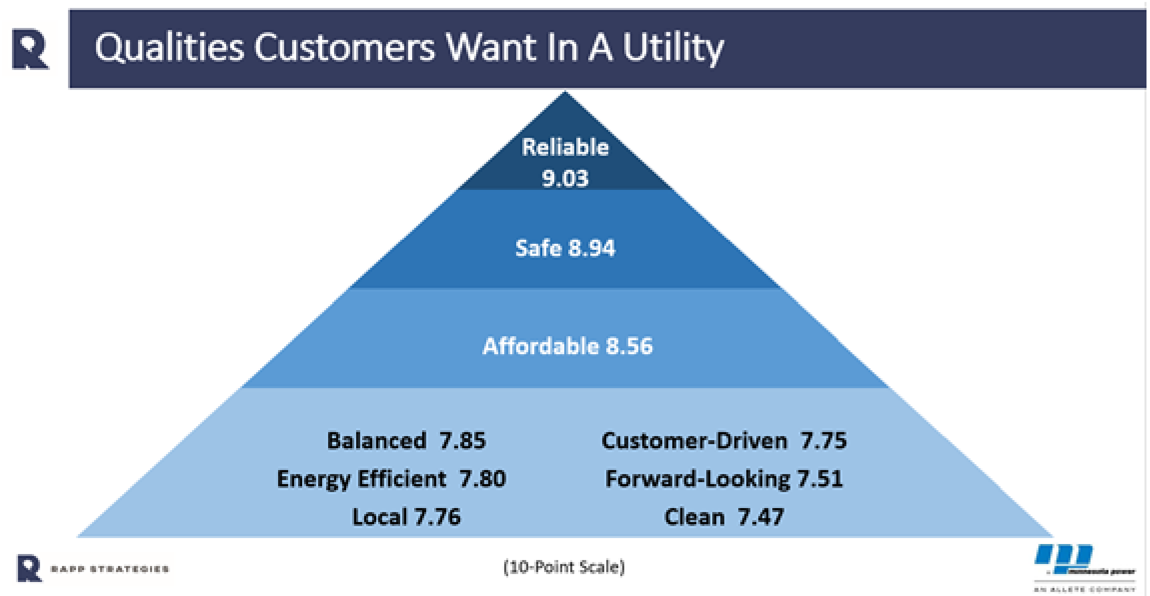
A. Minnesota Power has made both core infrastructure and technology related investments described later in my testimony to make measurable improvements in reliability. In Section V.C of my testimony, I discuss efforts on Grid Modernization along with Reliability and Power Quality spending.

B. Customer Relations/Customer Experience

Q. What is Minnesota Power's approach to customer relations and the customer experience?

A. Minnesota Power recognizes that, above all else, customers expect reliable, safe, and affordable electricity, as illustrated in Figure 3.

Figure 3. Customer Expectations Survey Results[17]



Amongst these qualities, reliability consistently ranks at the top of customer expectations. Minnesota Power's investments in modernizing the transmission and distribution system are focused on maintaining the high level of reliability our customers expect while delivering an increasingly sustainable energy supply.

Q. What are other aspects of a quality customer experience that customers desire in their utility?

Inherent to meeting these top customer priorities of reliable, safe, and affordable delivery of energy are the need to provide quality customer interactions through a variety of channels (i.e., in person, in writing, via email, over the phone, online, through social media). Further, convenience, transparency about services, timely updates regarding interruption to services, and clarity about costs and program offerings are essential to the customer experience. The Customer Overview Direct Testimony of Company witness Frank L. Frederickson discusses each of these expectations in more detail as well as the Company's enhancements to the customer experience and its programs, services, and reasonable rate offerings.

[17] *Minnesota Power Residential Customer Survey - Reputation*, RAPP STRATEGIES (2019).

Q. Does enhancing customer service require Minnesota Power to make investments in customer-service resources?

A. Yes. To meet our customers' needs, the Company must continually and prudently invest in new technologies and customer-facing improvements. This includes system optimizations and integrations to ensure a more comprehensive and streamlined experience for the customer, regardless of what channel they choose for interaction or receiving information.

Q. How do these investments improve customer service?

A. The Company's investments continually enhance automation and leverage AMI to provide timely and transparent information to customers. As an example, Minnesota Power is nearing completion of its AMI deployment and recently completed a holistic Customer to Meter ("C2M") solution. C2M involved upgrading the existing Customer Information System ("CIS") to an Advanced Meter Billing System that includes the following modules: Customer Information Billing and Rates, Meter Data Management ("MDM"), Smart Grid Gateway, Meter Asset Management, and Service Order Management. The Company's AMI deployment and C2M solution are discussed later in my testimony.

Together, these systems allow for additional enhancements to customer self-service options through the Company's MyAccount tool as well as sophisticated meter read estimations and advanced rate designs that support customer engagement in the continued deployment of renewable energy on the system. These investments are in addition to the Mobile Workforce System and the OMS referenced in the following section of my testimony. All of these systems have a customer-facing element. In addition to the system investments themselves, considerable investment in resources such as training, process improvements, web site updates, and analytics are needed to enhance the customer experience and ensure desired outcomes are measurable and attainable.

C. Grid Modernization Technology Solutions/Systems

Q. Has Minnesota Power continued its efforts to incorporate technology into its systems to leverage these advancements for the benefit of customers?

A. Minnesota Power has a number of technology initiatives related to customer service, customer data, reliability, and business efficiency. These initiatives improve how information is provided as well as how data is gathered, and will result in a number of gains in business efficiency. The section below talks about these initiatives in technology.

1. Advanced Metering Infrastructure

Q. What is AMI?

A. AMI is a two-way communication between utilities and customers that provides an integrated system of smart meters, communications networks, and data management.

In 2010, Minnesota Power began deploying the infrastructure and endpoints of an AMI system. This was done in part to help transition to a next generation technology required to overcome some of the operating and emerging obsolescence challenges associated with the AMR technology. Communications infrastructure for the AMI system was completed in 2019 with purchases and deployment of AMI meters continuing through 2023. Capital additions for AMI meters are included in the Metering section of Table 1. In Table 8, the Company has provided details related to the AMI deployment since the 2016 Rate Case as well as test year and future plans.

Table 8. Deployment Plan for AMI Meters

Year	AMI Meters Installed	Remaining AMR Meters
2016 Actual	11,092	92,084
2017 Actual	11,476	80,608
2018 Actual	13,155	67,453
2019 Actual	10,635	56,818
2020 Actual	35,437	21,381
2021 Plan	10,000	11,381
2022 Plan	10,000	1,381
2023 Plan	1,381	0*

*Likely won't be "0" in 2023 due to opt-outs

Q. How is Minnesota Power's AMI being used?

A. Since 2011, the OMS has been integrated with the Company's AMI system. This integration provides real-time messages from the AMI system when the power goes out at a customer service and when the power is restored to a customer service. The AMI system allows service dispatchers to "ping" individual customer meters to verify power restoration and service status manually.

Overall, the AMI system allows for efficient metering access, enhanced communication, and situational awareness between Minnesota Power and its customers. The meters act as "smart nodes" at each customer's premises, allowing a number of benefits including: efficient deployment of advanced time-based customer rate offerings; outage notifications; notification of service issues (such as low/high voltage, over current, and tamper warnings); improved load control (such as Dual Fuel and Controlled Access programs); more frequent customer usage data; and the ability to more quickly reconnect customers who have been involuntarily disconnected due to non-payment. The expansion of Minnesota Power's AMI capabilities lays the groundwork for further Smart Grid initiatives and improvements to the customer experience.

Q. How has the AMI system directly benefited customers?

A. Since the AMI system installation was initiated, there have been many customer benefits realized. One of the most critical improvements is the read rate improvement versus the

AMR system, which has resulted in fewer estimated bills sent to customers. The customer read rate percentage that the Company tracks is the number of billing reads the Company receives from the system that are acceptable for billing during the billing window. The AMI system currently provided a read rate greater than 98.6 percent of meters during the billing window of June 2020. The historic AMR system read rate was just over 97.4 percent, which resulted in a higher rate of estimated bills.

In addition, AMI usage data has been integrated with Minnesota Power's MyAccount customer portal. This allows for more granular 15-minute usage data to be displayed and to be compared with historical usage and/or average temperature. This data can be used by the customer to better understand their energy usage and see the changes when shifting activities or replacing appliances, lighting, or other electrical systems.

Another critical benefit has been the ability for the AMI system to detect an over-temperature, sometimes referred to as a "hot socket" condition, to minimize the likelihood of a potential catastrophic failure at a meter socket. Minnesota Power began tracking these alarms since 2012 and has had 660 unique hazard alarms, 575 of which were conditions that required further action to remediate a hazard.

In addition, AMI meters with remote capability can be used to disconnect and reconnect customers. While disconnections need to follow Minnesota Rules and Statutes regarding in-person contact attempts, the remote aspect for reconnections can provide for more timely reconnections. This functionality and related savings are being explored as part of the Company's Reconnect Pilot.

Q. What is the status of the Company's Remote Reconnect Pilot Program?

A. Minnesota Power's Remote Reconnect Pilot was approved by the Commission on December 9, 2020 under Docket No. E015/M-19-766. This is a voluntary three-year pilot program, under which residential electricity customers whose service has been disconnected due to non-payment would have the option to have their service reconnected remotely after meeting reconnection requirements. A participating customer with a remote-capable meter could have service reconnected within minutes after calling customer service, eliminating the need for Minnesota Power to send staff to the customer's location to reconnect service in person and allowing for a waived reconnection fee for the customer.

Due to the economic impacts of the COVID-19 pandemic, and particularly in response to the issuance of the Governor's Emergency Executive Order, Minnesota Power voluntarily took several proactive measures to provide protections and enhance safety for employees, customers, and communities during the peacetime emergency. Part of these actions included suspension of disconnections for residential customers facing financial hardship as a result of the coronavirus pandemic. In its August 13, 2020 Order under Docket No. E,G999/CI-20-375, the Commission ordered: suspension of disconnections for residential customers; suspension of negative reporting to credit agencies for residential customers; and waiving reconnection, service deposits, late fees, interest, and penalties for residential customers. In the Commission's May 26, 2021 Order in Docket No. E,G999/CI-20-375, the Commission adopted a modified Consumer Advocates' Transition Plan and allowed for the resumption of disconnections on August 2, 2021. With the resumption of disconnections, Minnesota Power is in the process of deploying remote-capable meters, timed with reconnection of service, to realize operational efficiency and maximize the potential savings to customers in terms of Company costs as well as direct costs such as future reconnection fees.

Q. What are the net cost changes due to the Company's Remote Reconnect Pilot Program?

A. The Remote Reconnect Pilot Program rollout was delayed due to the suspension of many collections activities in response to the COVID-19 pandemic. Resumption of disconnections began on a limited basis as of August 2, 2021. As of October 1, 2021, there were approximately 3,100 remote-capable meters installed for residential accounts. There had been 149 disconnections and 115 reconnections with these accounts. Cold Weather Rule protections began October 1, 2021 and run through April 30, 2022, which aligns with the timing of the transition plan referenced above. Given the unique operating constraints of 2020 through the end of Cold Weather Rule in 2022, Minnesota Power does not have representative net cost changes specifically related to the Remote Reconnect Pilot to share at the time of this filing. The Company intends to report on the Remote Reconnect Pilot Program status in its upcoming and future SRSQ report.

2. Customer to Meter Project

Q. What is the C2M project?

A. Previously referred to as the MDM, C2M is a flexible, highly scalable upgraded customer information solution with advanced MDM capabilities designed to meet the needs of electric, gas and water services. The project began in 2018 with the purchase of software. The system implementation period began in 2019 and concluded in 2021, with a system go-live in April 2021. Currently the system is in the midst of a stabilization period while next phase planning is underway. Initial phase deployment was to build the foundations of the C2M solution that included an upgrade to the existing customer information application and implementing the modules within the Advanced Meter Billing System that includes MDM. Phase 2 includes the expansion of analytics, additional metering capabilities with other core systems, and exploring further complex and flexible billing functionality.

Q. What is the Company doing to maximize the value of the C2M project?

A. The primary aim of C2M is to implement a single software solution to provide the functionality of an Advanced Meter Billing System. This means one database, one framework and application, and one unified user interface. The Company will realize many benefits including cost, efficiency, and functionality within a robust multi-module platform that has streamlined installation and maintenance. This holistic solution involved upgrading the existing CIS to an Advance Meter Billing System that includes the following modules: Customer Information Billing and Rates, MDM, Smart Grid Gateway, Meter Asset Management, and Service Order Management.

The C2M project will improve management of operational devices in the field such as meters and metering equipment. It will make the status of service orders more transparent and allow proactive identification and response to meter alarms and issues.

Benefits for customers include:

- Capability to automate billing for Time of Day and other time-varying rates;
- Energy use data in MyAccount will appear more clearly;
- Billing estimates will be more accurate;
- Remote service connections and disconnections will be simplified; and
- New programs and rates for innovative technology such as electric vehicles will be more readily implemented.

This solution will provide the foundation to respond more quickly to changing regulatory and marketing demands. It will improve the Company's understanding of its customers via data analytics, rate guidance, and targeted program offerings to customers, as well as the efficiency and accuracy of the meter asset management process. Additionally, it will reduce risk through elimination of the in-house developed system for distributing and analyzing meter data.

3. Mobile Workforce Management

Q. What is the Mobile Workforce System?

A. The Mobile Workforce System is a set of software applications that allows field workers to use a mobile device to complete service requests. The Mobile Workforce System capabilities include: automated scheduling based on work type, priority, and location; collection of various types of data in the field; automated completion of work in our source systems for work management; and creation of service requests in the field.

Q. What opportunities does the Mobile Workforce System provide for efficiency and cost savings?

A. Minnesota Power has identified Mobile Workforce Technology as a company-wide priority for our field workforce. As part of a broader strategy of business process automation, the Mobile Workforce System provides the following efficiencies: eliminates paper work orders, optimizes schedule and automates routing, increases transparency with data, and provides real-time status of work. The scheduling transparency and improved access to hazards at customer premises in the field also benefits worker safety.

Q. What does the Mobile Workforce System provide to customers?

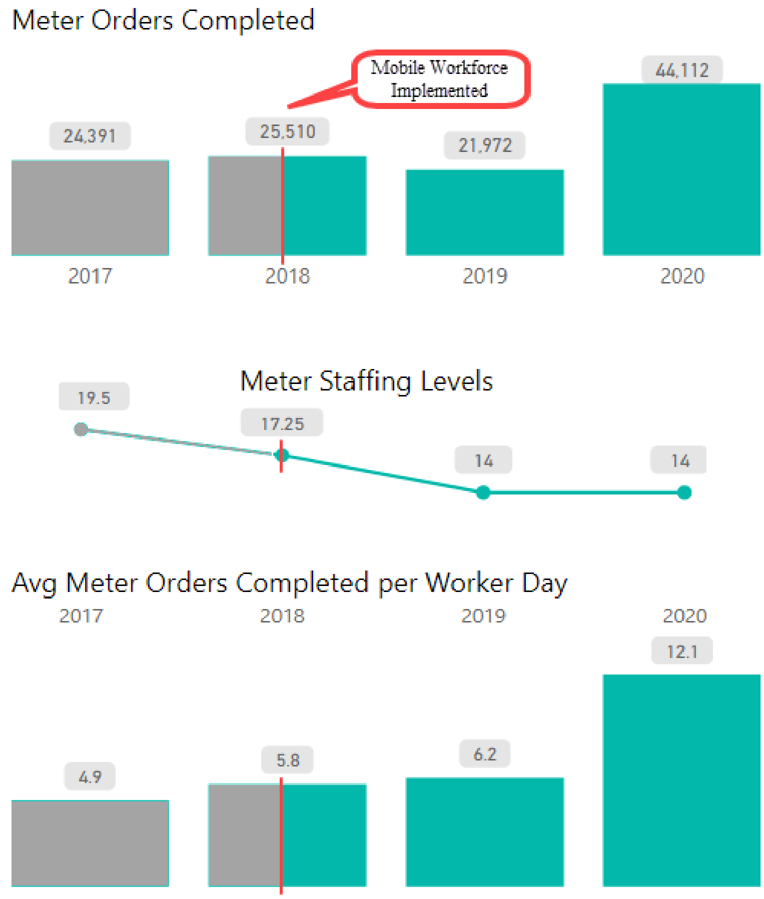
A. The Mobile Workforce System benefits customers by connecting field to office in a way not previously available to our employees. These allow for real-time completion of orders, elimination of paper, and automated routing, which all contribute to more efficient operations and result in better billing accuracy and a better customer experience. The system also positions Minnesota Power to systematically share scheduling and completion information with our customers.

Q. Please explain how the mobile workforce system improves customer service for Minnesota Power.

A. The first phase (i.e., meter and collections work) of the Mobile Workforce System initiative realized the elimination of nearly all manual phone calls and data entry for work order completion plus an increase in field productivity after the first full year of implementation (June 2018 to May 2019).

Mobile Workforce went live for meter and collections employees on May 30, 2018. The charts in Figure 6 show metrics for Orders Completed by Month, Staffing Levels, and Orders Completed per Worker Day by Month from 2017 (pre-Mobile Workforce) through 2020. Counts of Worker Days per month exclude holidays and weekends. The metrics show a significant increase in productivity since Mobile Workforce went live and an even greater productivity increase in 2020 as demonstrated by total orders completed. In 2020, more orders were completed with fewer staff, which allows staff to respond more quickly to customer requests with more accurate data entry.

Figure 4. Meter Deployment Metrics (2017-2020)



In addition to meter orders, Minnesota Power has been expanding the scope of our Mobile Workforce system to include trouble orders and scheduled line work. Trouble orders were added to the system in late 2019/early 2020; in 2020, more than 5,000 trouble orders were completed via a mobile device in the field. Scheduled line work is the most recent addition; in the first half of 2021, 2,300 scheduled work assignments have been completed via a mobile device.

4. Reevaluation of Transmission and Distribution Maintenance Program Needs

Q. What work is Minnesota Power doing to reevaluate its operations maintenance program needs in the Transmission and Distribution areas?

A. Minnesota Power continues to prioritize sound investments in the distribution system to maintain and improve reliability and is focused on the maintenance and replacement of critical assets as necessary to maintain safe system performance. Minnesota Power increased focus on distribution equipment maintenance and replacement since the 2016 Rate Case and will continue to develop these programs into the future. Resources and engineering staff have been added to the Distribution Asset Management department to focus on inspections, preventative maintenance activities, and work creation as an outcome of these activities.

Q. How is this changing the maintenance program?

A. Minnesota Power can now monitor larger areas for power quality issues. Over 90 percent of its system has AMI meters installed on customer premises. These meters are polled each month and the voltage tolerances are reviewed to aggregate a list of potential issues. These issues are then reviewed by engineering resources to look for signs of failing equipment, overloaded transformers, or long secondary runs to customer sites.

Q. How does Minnesota Power resolve customer power quality issues?

A. Minnesota Power also resolves customer power quality issues on a case–by–case basis. When a customer calls with a complaint or questions regarding a power quality issue, Minnesota Power investigates and resolves all problems found to be caused by the Company. In the event of complaints regarding low voltage or high voltage, Minnesota Power will do an investigation of the customer's service and check for loose or overheated connections. If no problem is found or if the problem is intermittent, the Company will install a recording voltmeter. This meter allows for monitoring of the voltage over time and under various customer and system loading conditions. If those recordings demonstrate that the Company is not meeting its ANSI C84.1 service entrance voltage standards of +/- 5 percent of nominal voltage, Minnesota Power performs the required maintenance in order to bring the voltage within the prescribed limits. Requests from customers for power quality studies are infrequent.

Q. What other initiatives has the Company been undertaking to reevaluate and improve its maintenance program?

A. The Company has made several advancements with regard to tracking and improving the frequency of failed equipment.

First, Minnesota Power recently developed an application that allows any employee to identify areas of concern as employees are making observations on the system. The employee reports the issue by scanning a barcode placed on the equipment and reporting the repairs/replacement needed. This application creates a service request and is followed up with a work order to prevent the issue from creating an outage in the future. In the last 42 months, the company has received over 5,500 observations and has remedied over 79 percent of those observations. The Company expects to see rates of failed equipment decrease in future years as these issues are resolved.

Second, the Company has focused on preventative maintenance activities on distribution assets such as switches, reclosers, regulators, and capacitor banks. By performing proactive maintenance on equipment, the Company anticipates a reduced equipment failure rate and improved reliability.

Third, Minnesota Power has invested in equipment that requires less or no maintenance. This new equipment has better technology to clear temporary faults, which should increase reliability and reduce line crews being dispatched to respond to outage calls. Also, the newer equipment is lower cost than traditional distribution equipment. Between the lower purchase cost and a reduced need for maintenance, it will be less expensive to operate the equipment over its service life. Trip Savers are a great example of this newer technology; Trip Savers are a re-closer in a cutout body. The Company decided to use this equipment to replace its aging oil-filled re-closers out on the distribution feeders. Aging cutouts are another opportunity to use Trip Savers instead of replacing the older cutout with the same technology.

Fourth, the Company is conducting audits throughout its distribution service territory to identify equipment that may need attention. This equipment will be brought into the work management system and placed on a preventative maintenance schedule. These audits allow Minnesota Power to prioritize which equipment needs the most attention based on age and number of customers affected if the equipment fails. By conducting preventative maintenance activities on equipment, customers will see decreased outages and increased reliability, and Minnesota Power will see longer service life of its equipment with less failure rates.

Fifth, the ground-line program is also being updated to treat every pole as mentioned in Section III.C of my testimony. The ground line inspections that result in capital projects that extend the lives of the poles will shift from traditionally O&M expense to mostly capital, resulting in lower O&M costs starting in 2022.

Finally, Minnesota Power is pursuing more strategic undergrounding projects which will reduce system maintenance and costs related to outage response and vegetation management activities. More information on the Company's strategic undergrounding program can be found in Section III.C and in our IDP.

5. Geographic Information System

Q. What is the GIS?

A. GIS is the suite of spatial technologies that Minnesota Power uses to store, analyze, and report on the location and geographical aspects of its electrical system. At its core, GIS is a relational database that tracks information related to "features," meaning specific assets or components within the system. The GIS contains information on the geographic location of the feature and also contains asset or component-specific information about each feature. The information about each feature can be used to visualize that feature on a map as well as analyze it in relation to other spatial datasets.

These datasets can be ones maintained by Minnesota Power, like connected customers or primary, or third-party datasets like rail lines. Using the data within the GIS, Minnesota Power can tell how many transformers are installed within our service territory. These data allow Minnesota Power to count the customers served by those transformers and also identify which counties those customers reside in. While the GIS system has been in place since 2003, Minnesota Power continues to find ways to maximize the technology to support customer needs.

Q. How does the existing GIS system serve customers?

A. The GIS, as well as the staff that support and operate it, serves external customers in a variety of visible and invisible ways. Perhaps its most core support is with the OMS, discussed later in this section. Data is translated out of the GIS into the OMS, which allows for rapid restoration of power during storms or other outages and feeds the information in the customer outage map, which is available for viewing by customers on the Company's website and through the Minnesota Power app.

The GIS also sends data to Gopher State One Call in support of the statewide one–call hotline. The information is used to determine which utilities have underground facilities that could be affected by customer construction activities. This same information is also provided to locating contractors that then verify the physical location of underground assets and ensure the safety of customers. This data is also provided to customers on an ad-hoc basis for planning purposes.

Customers calling into the call center to report streetlight issues are indirectly interacting with a system created out of the GIS. Call center staff interact with a map of existing lights and a simple form to collect information on the reported issue. This data is then automatically routed to field staff who find and fix the issue.

The GIS system also supports AMI meter alarms and feeder voltage analysis, allowing internal support personnel to identify customer power quality and service symptoms prior to an outage or other major problem.

Q. How will future changes improve the Company's GIS abilities?

A. The company in the midst of transitioning to an emerging GIS model that connects data across all of the systems, from generation to customer. This work began in 2019 and is planned for completion in 2022. Following this work, GIS staff will no longer need to spend time transferring data between systems in order to model impacts between the various components of the electrical system or create backups of the GIS in order to do historical studies and reports.

The underlying technology supporting the GIS is being changed to support a scalable and mobile workforce. This change allows for centralized administration of users and editors of the GIS and will reduce the hardware needed to support the GIS. Moving to a more real-time GIS system will also remove some of the delays in current data integrations. This will allow the Company to act on information faster and resolve issues in a more timely manner.

The GIS system also features a survey application that has led to the elimination of many paper processes for data collection. This survey tool is one of the most used applications from our GIS vendor. It is a form-based entry tool that runs across all of the mobile and desktop technologies, providing easy access with desired information requested in a logical format.

6. Outage Management System

Q. What is the OMS?

A. The OMS manages the detection, location, isolation, repair, and restoration of faults which occur unexpectedly on the distribution system in addition to managing planned distribution outages. It provides support to operators at all stages of the outage life cycle, starting from events (customer reports, AMI outage notifications, Supervisory Control and Data Acquisition ("SCADA") operations, and notification from the field crews) and concluding with the restoration of electric service. The OMS is the overall coordinator of all tasks, processes, and record keeping associated with the resolution of distribution outages and is the single source for communicating outage information to internal and external stakeholders (primarily through the outage map on the website and available through the Minnesota Power app).

Q. How is the Company utilizing the current OMS system?

A. The OMS must utilize information provided from the GIS for an accurate representation of the distribution system. GIS data must go through a complex mapping process before it can be utilized by the OMS. The current GIS technology is not fully compatible with the OMS, which has resulted in the OMS having inaccurate and/or incomplete representation of portions of the distribution system. This has limited the OMS's ability to accurately predict outages in certain locations and, in some cases, for the OMS to predict outages where none were actually present. In addition, the OMS application and the servers and database it runs on are all approaching end of support, increasing the potential for security, functionality, and performance issues to emerge for which no solution is available from the manufacturer.

Q. How will future changes to the OMS impact customers?

A. Given these issues, Minnesota Power is in the planning phases of a project to replace the OMS with a product that will improve integration with the GIS to eliminate or greatly reduce the mapping errors described above. This mapping improvement will result in the OMS having a more accurate representation of the distribution system. This will reduce restoration times by locating isolated outages and improving prioritization of restoration work in multi-outage situations. Customers will be provided more accurate restoration times. An upgraded OMS will position Minnesota Power to more readily implement a Distributed Energy Resource Management System and/or an Advanced Distribution Management System to control widespread use of solar and other distribution generation sources if and when the need arises.

7. Communication System Improvements

Q. Please describe the communication system improvements made during recent years and explain how they benefit the Company and its customers?

A. Minnesota Power owns and operates a communications transport system that consists of fiber optics, microwave radios, leased services, and other technologies. This system provides communications for all areas of Minnesota Power, including transmission SCADA, transmission line protection, distribution SCADA, land mobile radio, business IT systems, voice, video and others. A variety of communications methods are used based on the cost and needed reliability of the application. The Company has recently commenced three large system replacements to ensure uninterrupted and reliable communications to support all aspects of utility operations. The annual capital additions related to these improvements are reflected in the Cyber Technology Services section of Table 1 in my Direct Testimony.

Q. What is the first large system replacement?

A. The first large project is a replacement of the existing Synchronous Optical Networking ("SONET") system. The SONET system is the core fiber optic transport platform at Minnesota Power. SONET technology is no longer commercially available, and our system is past manufacturer end of sale and manufacturer end of support meaning the Company can no longer purchase replacement parts or upgrade firmware for security enhancements. A Multiprotocol Label Switching ("MPLS") system has been selected to replace the SONET system. This new MPLS system will provide a secure and reliable fiber optic transport platform while leveraging new technology, allowing Minnesota Power to expand its communications transport system and enabling data-intensive grid modernization initiatives.

Q. Please describe the second large system replacement.

A. The second large project is a replacement of the existing transport microwave radios. Minnesota Power's transport microwave radios provide reliable backhaul communications to many portions of its service territory and are a critical part of the communications transport system. The current fleet of radios are past manufacturer end of sale and manufacturer end of support, meaning the Company can no longer purchase replacement parts or upgrade firmware for security enhancements. The Company has selected a replacement radio and begun replacing our radio hops. The technology advancements in the new radios allow for faster speeds, enabling data-intensive grid modernization initiatives.

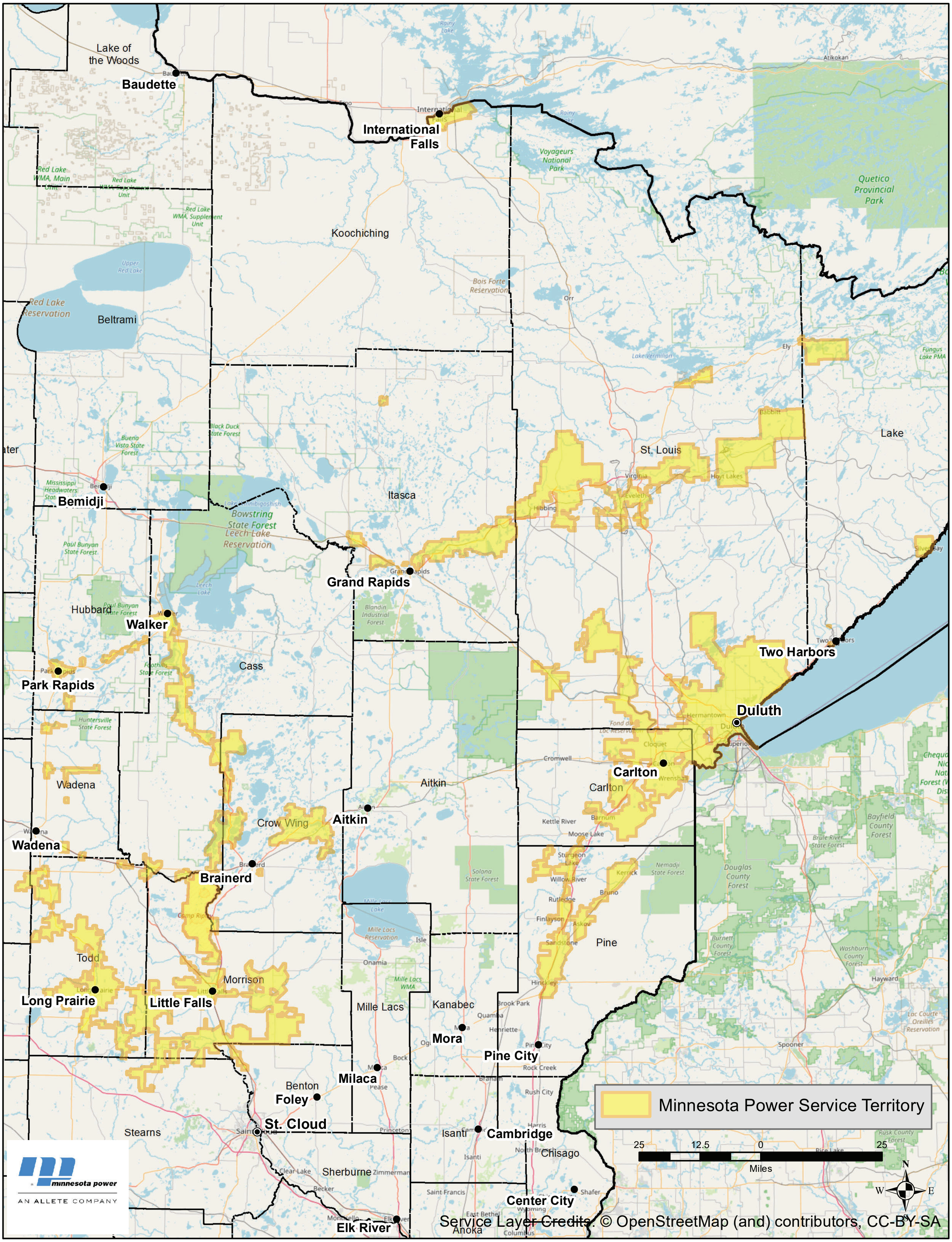
Q. What will be required for the third large system replacement?

A. The third large project is an upgrade of our land mobile radio ("LMR") system. Minnesota Power owns and operates a private LMR system to provide reliable mission critical push to talk voice communications for utility operations. The existing hardware is past manufacturer end of sale and manufacturer end of support meaning the Company can no longer purchase replacement parts or upgrade firmware for security enhancements. We are in the process of replacing our dispatch console system and upgrading the LMR system to a digital mobile radio ("DMR") system. The upgrade to DMR will also enable us to pilot a solution that will provide low speed data over the existing LMR infrastructure as a potential low cost solution for grid modernization initiatives like distribution automation.

VI. CONCLUSION

Q. Does this complete your testimony?

A. Yes.


Minnesota Power Service Territory
Baudette
International Falls
Koochiching
Beltrami
Bemidji
Itasca
St. Louis
Lake
Grand Rapids
Hubbard
Walker
Park Rapids
Cass
Two Harbors
Duluth
Carlton
Wadena
Aitkin
Crow Wing
Brainerd
Pine
Todd
Morrison
Long Prairie
Little Falls
Mille Lacs
Kanabec
Mora
Pine City
Milaca
Benton
Foley
St. Cloud
Stearns
Isanti
Cambridge
Chisago
Sherburne
Center City
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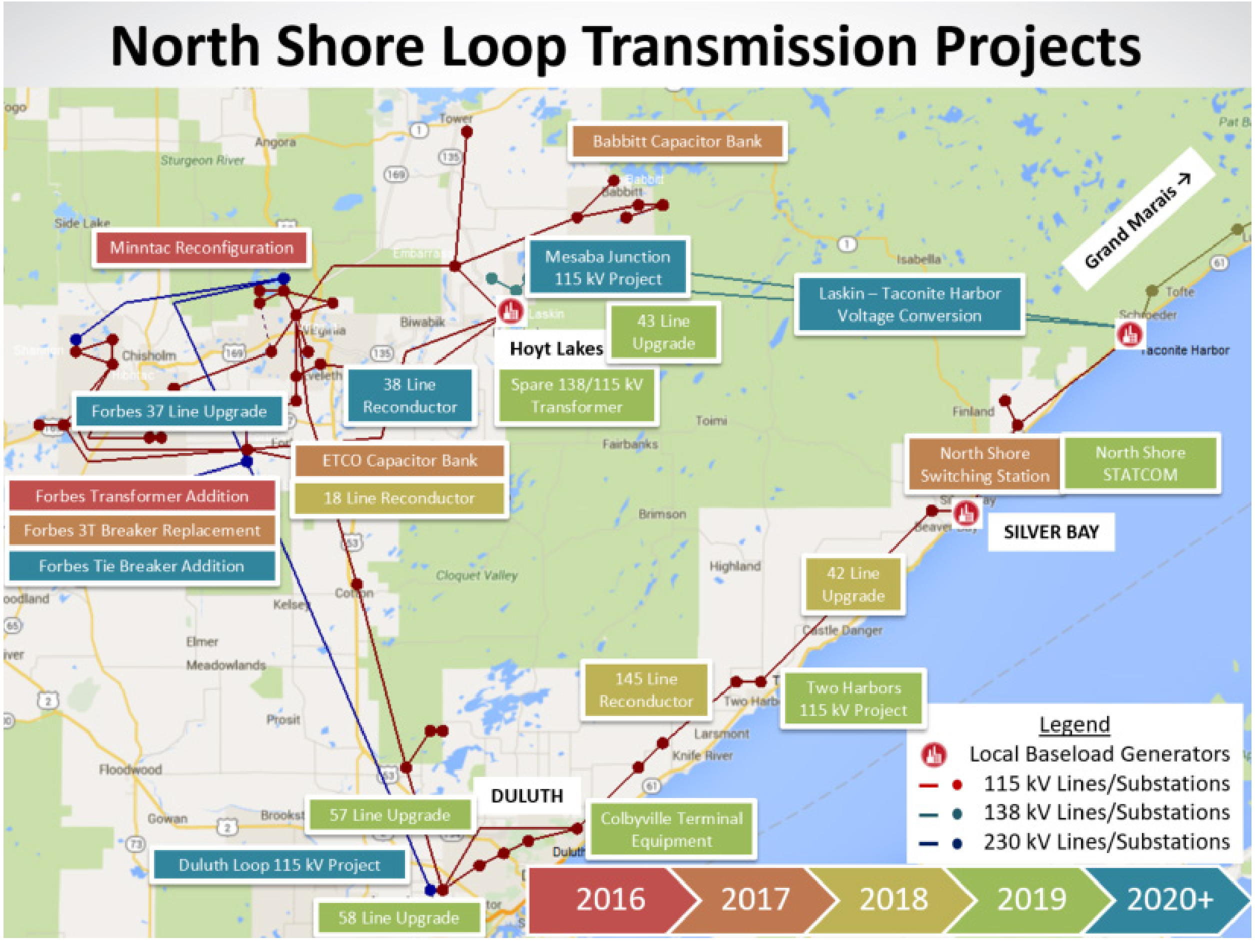
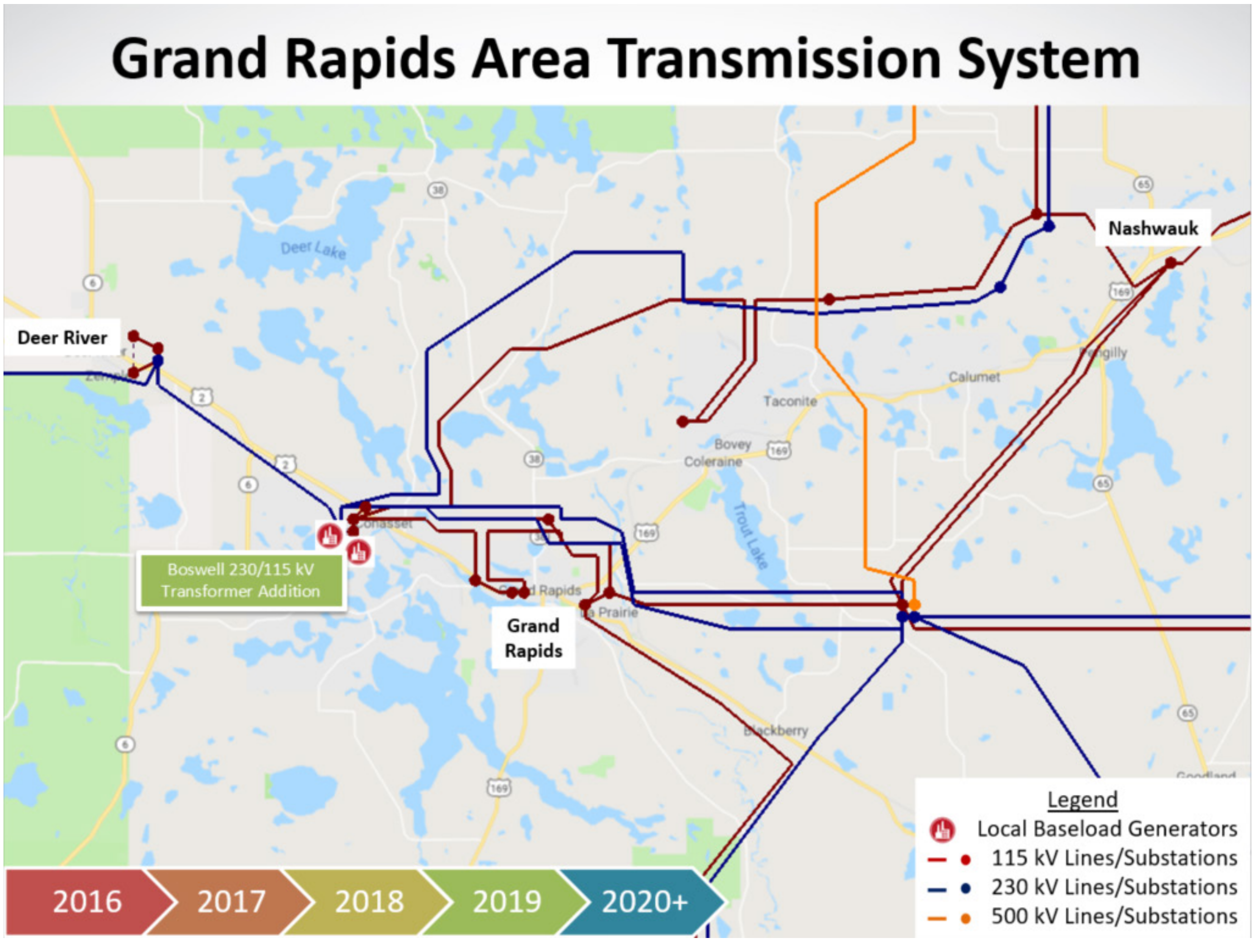
25 12.5 0 25
Miles
minnesota power
AN ALLETE COMPANY
Service Layer Credits: © OpenStreetMap (and) contributors, CC-BY-SA


North Shore Loop Transmission Projects
Babbitt Capacitor Bank
Minntac Reconfiguration
Mesaba Junction 115 kV Project
Laskin – Taconite Harbor Voltage Conversion
Grand Marais ↗
43 Line Upgrade
Hoyt Lakes
38 Line Reconductor
Spare 138/115 kV Transformer
Forbes 37 Line Upgrade
ETCO Capacitor Bank
18 Line Reconductor
Forbes Transformer Addition
Forbes 3T Breaker Replacement
Forbes Tie Breaker Addition
North Shore Switching Station
North Shore STATCOM
SILVER BAY
42 Line Upgrade
145 Line Reconductor
Two Harbors 115 kV Project
DULUTH
57 Line Upgrade
Colbyville Terminal Equipment
Duluth Loop 115 kV Project
58 Line Upgrade
Legend
Local Baseload Generators
115 kV Lines/Substations
138 kV Lines/Substations
230 kV Lines/Substations
2016
2017
2018
2019
2020+


Grand Rapids Area Transmission System
Deer River
Nashwauk
Deer Lake
Taconite
Calumet
Bovey
Coleraine
Trout Lake
Boswell 230/115 kV Transformer Addition
Grand Rapids
La Prairie
Blackberry
Legend
Local Baseload Generators
115 kV Lines/Substations
230 kV Lines/Substations
500 kV Lines/Substations
2016
2017
2018
2019
2020+

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

Year Type	Actuals												Projected Year			Test Year		
Year	2017			2018			2019			2020			2021			2022		
Recovery	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin
Base Rates	**38.3M**	**35.9M**	**2.5M**	**28.8M**	**35.5M**	**-6.7M**	**34.6M**	**32.4M**	**2.2M**	**50.1M**	**33.7M**	**16.4M**	**57.3M**	**32.0M**	**25.4M**	**57.0M**	**34.2M**	**22.8M**
Admin Schedule	0.0M	2.3M	-2.3M		2.4M	-2.4M		2.3M	-2.3M		2.3M	-2.3M		1.6M	-1.6M		2.7M	-2.7M
Ancillary Services	0.7M	0.4M	0.3M	0.6M	0.6M	0.0M	0.5M	1.1M	-0.5M	0.2M	0.9M	-0.7M	0.1M	0.1M	0.1M	0.8M	0.4M	0.3M
Base Transmission	28.5M	22.7M	5.9M	26.4M	24.4M	2.0M	26.2M	23.3M	3.0M	26.7M	21.3M	5.5M	25.1M	22.0M	3.2M	27.0M	21.5M	5.5M
GRE Joint Pricing Zone	0.0M	2.8M	-2.8M	0.0M	2.8M	-2.8M		2.8M	-2.8M	0.3M	0.4M	-0.1M	1.0M	0.0M	1.0M	0.0M	1.3M	-1.2M
Manitoba Must Take Fee										12.9M		12.9M	22.3M		22.3M	20.9M		20.9M
MISO / FERC Refund Accrual	0.0M	0.0M	0.0M		0.0M	0.0M	-3.8M	-4.3M	0.5M									
MISO Transmission Rates True-Up				-4.4M		-4.4M	3.4M		3.4M	-0.6M		-0.6M	0.4M		0.4M	0.3M		0.3M
NREAC	8.7M	7.7M	0.9M	5.6M	5.3M	0.3M	7.7M	7.2M	0.4M	10.0M	8.8M	1.2M	7.6M	8.4M	-0.7M	7.7M	8.3M	-0.6M
Wheeling	0.5M		0.5M	0.6M		0.6M	0.6M		0.6M	0.4M		0.4M	0.7M		0.7M	0.4M		0.4M
Direct Customer	**3.8M**		**3.8M**	**2.0M**		**2.0M**	**2.9M**	**1.0M**	**1.9M**	**2.8M**	**1.2M**	**1.6M**	**3.0M**	**1.3M**	**1.8M**	**3.1M**	**1.3M**	**1.8M**
Customer	1.1M		1.1M	0.0M		0.0M	1.0M	1.0M	0.0M	1.2M	1.2M	0.0M	1.3M	1.3M	0.0M	1.3M	1.3M	0.0M
GRE Distribution	2.7M		2.7M	2.0M		2.0M	1.9M		1.9M	1.6M		1.6M	1.8M		1.8M	1.8M		1.8M
Transmission Cost Recovery Rider	**27.2M**	**35.4M**	**-8.2M**	**25.2M**	**34.4M**	**-9.2M**	**19.7M**	**36.4M**	**-16.7M**	**17.5M**	**32.1M**	**-14.6M**	**19.2M**	**32.1M**	**-12.9M**	**19.0M**	**33.7M**	**-14.7M**
Cost Shared Projects	27.2M	35.4M	-8.2M	25.2M	34.4M	-9.2M	19.7M	36.4M	-16.7M	17.5M	32.1M	-14.6M	19.2M	32.1M	-12.9M	19.0M	33.7M	-14.7M
Total	**69.4M**	**71.2M**	**-1.9M**	**56.0M**	**69.9M**	**-14.0M**	**57.1M**	**69.8M**	**-12.6M**	**70.4M**	**67.0M**	**3.4M**	**79.6M**	**65.4M**	**14.2M**	**79.0M**	**69.3M**	**9.8M**

Year Type	Actuals												Projected Year			Test Year		
Year	2017			2018			2019			2020			2021			2022		
Recovery	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin
Base Rates	38.3M	35.9M	2.5M	28.8M	35.5M	-6.7M	34.6M	32.4M	2.2M	50.1M	33.7M	16.4M	57.3M	32.0M	25.4M	57.0M	34.2M	22.8M
Direct Customer	3.8M		3.8M	2.0M		2.0M	2.9M	1.0M	1.9M	2.8M	1.2M	1.6M	3.0M	1.3M	1.8M	3.1M	1.3M	1.8M
Transmission Cost Recovery Rider	27.2M	35.4M	-8.2M	25.2M	34.4M	-9.2M	19.7M	36.4M	-16.7M	17.5M	32.1M	-14.6M	19.2M	32.1M	-12.9M	19.0M	33.7M	-14.7M
Total	**69.4M**	**71.2M**	**-1.9M**	**56.0M**	**69.9M**	**-14.0M**	**57.1M**	**69.8M**	**-12.6M**	**70.4M**	**67.0M**	**3.4M**	**79.6M**	**65.4M**	**14.2M**	**79.0M**	**69.3M**	**9.8M**

Amounts may not total due to rounding.

Minnesota Power System Third-Party Revenues and Expenses
(MN Jurisdiction)

Year Type	Actuals												Projected Year			Test Year		
Year	2017			2018			2019			2020			2021			2022		
Recovery	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin
Base Rates	**31.7M**	**29.7M**	**2.0M**	**24.1M**	**29.8M**	**-5.7M**	**29.5M**	**27.6M**	**1.8M**	**41.7M**	**28.0M**	**13.7M**	**47.3M**	**26.4M**	**21.0M**	**47.0M**	**28.1M**	**18.9M**
Admin Schedule	0.0M	1.9M	-1.9M		2.0M	-2.0M		1.9M	-1.9M		1.9M	-1.9M		1.3M	-1.3M		2.2M	-2.2M
Ancillary Services	0.5M	0.3M	0.2M	0.5M	0.5M	0.0M	0.4M	0.9M	-0.5M	0.2M	0.7M	-0.5M	0.1M	0.0M	0.1M	0.6M	0.3M	0.3M
Base Transmission	23.6M	18.7M	4.9M	22.1M	20.4M	1.7M	22.3M	19.9M	2.5M	22.3M	17.7M	4.6M	20.7M	18.1M	2.6M	22.3M	17.7M	4.6M
GRE Joint Pricing Zone	0.0M	2.3M	-2.3M	0.0M	2.3M	-2.3M		2.4M	-2.4M	0.3M	0.4M	-0.1M	0.8M	0.0M	0.8M	0.0M	1.0M	-1.0M
Manitoba Must Take Fee										10.7M		10.7M	18.4M		18.4M	17.2M		17.2M
MISO / FERC Refund Accrual	0.0M	0.0M	0.0M		0.0M	0.0M	-3.2M	-3.7M	0.4M									
MISO Transmission Rates True-Up				-3.7M		-3.7M	2.9M		2.9M	-0.5M		-0.5M	0.3M		0.3M	0.3M		0.3M
NREAC	7.2M	6.4M	0.8M	4.7M	4.5M	0.2M	6.5M	6.2M	0.3M	8.4M	7.3M	1.0M	6.3M	6.9M	-0.6M	6.3M	6.8M	-0.5M
Wheeling	0.4M		0.4M	0.5M		0.5M	0.5M		0.5M	0.4M		0.4M	0.6M		0.6M	0.3M		0.3M
Direct Customer	**3.2M**		**3.2M**	**1.7M**		**1.7M**	**2.5M**	**0.8M**	**1.6M**	**2.4M**	**1.0M**	**1.4M**	**2.5M**	**1.0M**	**1.5M**	**2.6M**	**1.1M**	**1.5M**
Customer	0.9M		0.9M	0.0M		0.0M	0.9M	0.8M	0.0M	1.1M	1.0M	0.0M	1.1M	1.0M	0.0M	1.2M	1.1M	0.1M
GRE Distribution	2.2M		2.2M	1.7M		1.7M	1.6M		1.6M	1.3M		1.3M	1.4M		1.4M	1.4M		1.4M
Transmission Cost Recovery Rider	**22.5M**	**29.2M**	**-6.8M**	**21.1M**	**28.8M**	**-7.8M**	**16.8M**	**31.1M**	**-14.3M**	**14.6M**	**26.7M**	**-12.1M**	**15.9M**	**26.5M**	**-10.6M**	**15.6M**	**27.7M**	**-12.1M**
Cost Shared Projects	22.5M	29.2M	-6.8M	21.1M	28.8M	-7.8M	16.8M	31.1M	-14.3M	14.6M	26.7M	-12.1M	15.9M	26.5M	-10.6M	15.6M	27.7M	-12.1M
Total	**57.4M**	**58.9M**	**-1.5M**	**46.8M**	**58.6M**	**-11.8M**	**48.7M**	**59.5M**	**-10.9M**	**58.6M**	**55.7M**	**2.9M**	**65.7M**	**53.9M**	**11.8M**	**65.2M**	**56.9M**	**8.3M**

Year Type	Actuals												Projected Year			Test Year		
Year	2017			2018			2019			2020			2021			2022		
Recovery	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin	Revenue	Expense	Margin
Base Rates	31.7M	29.7M	2.0M	24.1M	29.8M	-5.7M	29.5M	27.6M	1.8M	41.7M	28.0M	13.7M	47.3M	26.4M	21.0M	47.0M	28.1M	18.9M
Direct Customer	3.2M		3.2M	1.7M		1.7M	2.5M	0.8M	1.6M	2.4M	1.0M	1.4M	2.5M	1.0M	1.5M	2.6M	1.1M	1.5M
Transmission Cost Recovery Rider	22.5M	29.2M	-6.8M	21.1M	28.8M	-7.8M	16.8M	31.1M	-14.3M	14.6M	26.7M	-12.1M	15.9M	26.5M	-10.6M	15.6M	27.7M	-12.1M
Total	**57.4M**	**58.9M**	**-1.5M**	**46.8M**	**58.6M**	**-11.8M**	**48.7M**	**59.5M**	**-10.9M**	**58.6M**	**55.7M**	**2.9M**	**65.7M**	**53.9M**	**11.8M**	**65.2M**	**56.9M**	**8.3M**

Amounts may not total due to rounding.