Direct Testimony and Schedules
Ian R. Benson

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(IRB-1)

Transmission

November 1, 2019

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ian Benson. I am the Area Vice President for Transmission Strategy and Planning for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company – Minnesota (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 28 years of experience in the utility industry and have served in positions in nuclear generation, retail electric marketing, wholesale power purchases and sales, and transmission. In my current position as the Area Vice President for Transmission Strategy and Planning, my responsibilities include supervising department engineers in planning electric transmission system expansions, recommending specific construction projects to Xcel Energy management and the Midcontinent Independent System Operator, Inc. (MISO), and overseeing transmission related agreements with MISO and other counterparties and resolving wholesale customer transmission service concerns. My resume is attached as Exhibit___(IRB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital forecasts and operation and maintenance (O&M) expense requests for the transmission organization for purposes of determining electric revenue requirements and final rates in this proceeding. I also provide information related to third-party transmission expenses and wholesale transmission revenues and their impact on the Company's revenue requirements. Further, I discuss a pending Federal

Energy Regulatory Commission (FERC) complaint against the MISO transmission owners related to the return on equity (ROE) and its potential impact on our third-party transmission expenses and wholesale revenues. Finally, I report on methods for calculating transmission system line losses as required by the Commission's order in the Company's last electric rate case (Docket No. E002/GR-15-826).

Q. WHAT ARE THE KEY RESPONSIBILITIES AND OBJECTIVES OF THE TRANSMISSION ORGANIZATION?

A. The NSP Companies, NSPM and Northern States Power Company – Wisconsin (NSPW), own, operate, and maintain an integrated transmission system that has facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan (NSP System).

The transmission organization is responsible for the maintenance, management, and construction of these transmission facilities that allow energy to be safely and reliably transported from generating resources (both Company-owned and third-party owned) to the distribution systems that serve customers. The transmission organization is focused on ensuring that that NSP System is reliable, resilient, and able to efficiently accommodate an increasingly diverse and dispersed number of generators.

To meet these objectives, the transmission organization makes investments that maintain and improve the reliability of the transmission system. This includes investments that are necessary to maintain compliance with the mandatory standards set by the North American Electric Reliability Corporation (NERC) and the FERC. We are constantly studying our system to determine what additional infrastructure investments are needed as these standards are updated and as customer loads and generation mixes change.

Another important component of maintaining the reliability of the transmission system is replacing or refurbishing facilities that have either reached the end of their life or are in poor condition. Many of our transmission facilities were placed in-service more than 50 years ago and are reaching the end of their useful lives. The transmission organization has several programs that are focused on examining and evaluating the performance and condition of each component of the transmission system. We then prioritize new investments based on condition and past performance of the existing aging assets and make the necessary upgrades to maintain reliability of the system.

Finally, our transmission organization also makes investments to reliably and cost-effectively accommodate new generation. In recent years, we have witnessed unprecedented amounts of renewable energy seeking to interconnect to the grid. As of September 1, 2019, there were more than 92.4 gigawatts of new capacity in the MISO queue, the vast majority of which was new wind and solar projects. At the same time, Xcel Energy and other utilities are in the process of retiring large fossil fuel generation plants. This shifting generation mix has and will require transmission investment to provide additional capacity to the transmission system to facilitate integration of these new generators.

In the past, the Company's investments in initiatives such as CapX2020 and MISO's Multi-Value Projects (MVPs) provided the additional transmission capacity necessary to integrate large quantities of low-cost renewable energy, as well as reduce system congestion and support the reliability of the system. During this multi-year rate plan we will continue to further these objectives by constructing the Huntley–Wilmarth 345 kilovolt (kV) Project that will be placed in service in 2021. The Huntley–Wilmarth 345 kV Project is a MISO designated Market Efficiency Project that is designed to provide economic benefits by providing additional transmission capacity to allow low-cost wind generation in southern Minnesota and northern Iowa to reach customers.

The Huntley–Wilmarth 354 kV Project is the last major regional expansion project that the Company currently has planned, but additional capacity will be needed to accommodate the wind and solar currently in the MISO queue. Additional transmission investment will also be needed to support the Company's goal of serving customers with 100 percent carbon-free electricity by 2050.

To that end, Xcel Energy, along with its other CapX2020 partners, announced plans in August 2019 to conduct the CapX2050 Transmission Vision Study. This study will examine the transmission system that serves the Upper Midwest and identify system improvements and upgrades to accommodate the unprecedented amount of renewable energy in the MISO queue and to achieve regional utilities' renewable energy goals, including Xcel Energy's goal.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In my Direct Testimony, I will discuss the transmission organization and the NSP System. I will also describe the numerous entities, in addition to the Minnesota Public Utilities Commission, that regulate the transmission system.

I will explain that the transmission organization is proposing capital additions of approximately $134.3 million for 2020, $353.5 million for 2021, and $273.5 million for 2022 for NSPM and NSPW to support the objectives I discussed above. These capital additions include the Huntley–Wilmarth 345 kV Project for which the Company will seek rate recovery through the Transmission Cost Recovery (TCR) Rider. Company witness Mr. Benjamin C. Halama will discuss the TCR Rider in greater detail. I will describe the six capital budget categories that are driving transmission investments and the importance of these investments in maintaining a safe, reliable, and robust transmission system. I will provide details about the major planned investments and key capital projects that the transmission organization will place in service during the term of the multi-year rate plan.

I will also discuss the transmission O&M budgets for 2020 to 2022, which are driven by internal labor, contract labor and consulting, fees, and materials. The transmission O&M budget for 2020 is $39.2 million, $37.9 million in 2021, and $38.1 million in 2022. The budget for each of these years is below the most recent three-year historic average (2016 to 2018) of $41.6 million. I will provide further explanation as to why our O&M budget for each year is reasonable and allows us the ability to perform the work necessary to construct and maintain the transmission system.

Further, I will discuss the MISO third-party transmission expenses and wholesale transmission revenues that are budgeted for 2020 to 2022. The third-party transmission expense for 2020 is $88.1 million, 2021 is $92.4 million, and 2022 is $94.6 million, and these costs are the result of the NSP Companies serving their native load customers in five other MISO pricing zones and a small load outside of MISO. The wholesale transmission revenues for 2020 is $89.3 million, $92.1 million for 2021, and $94.5 million for 2022, and this revenue is the result of transmission services and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets.

Finally, I discuss potential methods to calculate line losses on the transmission system as required by the Commission's Order in the Company's last electric rate case.

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- *Section II* – Transmission System Business Unit
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – Third-Party Transmission Expenses and Wholesale Revenues
- *Section VI* –Transmission System Line Loss Analysis

II. TRANSMISSION SYSTEM BUSINESS UNIT

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S TRANSMISSION SYSTEM.

A. The NSP Companies, NSPM and NSPW are vertically-integrated electric utilities that own and operate electric transmission facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan. Together, the NSP Companies own an integrated transmission system comprising approximately 8,400 miles of transmission facilities operating at voltages between 34.5 kV and 500 kV, and approximately 551 transmission and distribution substations. The NSP Companies are transmission owning members of MISO. The NSP System is planned and operated on an integrated basis, and has been under the functional control of MISO since it began operations in February 2002. Transmission service over the NSP System is open access, and transmission service reservations can be requested and approved under the terms of the MISO Tariff.

Q. CAN YOU DESCRIBE THE CUSTOMERS SERVED BY THE NSP SYSTEM?

A. The NSP System serves the following two customer groups: (1) retail native loads in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan; and (2) the loads of other investor-owned utilities, cooperatives, and municipal LSEs, or wholesale customers. The wholesale customers comprise approximately 20 percent of the total demand on the NSP System with the remaining demand comprised of retail native load customers. From a transmission planning and transmission service perspective, our retail customers and the wholesale customers require the same level of service, and as a result, the system is planned to serve the needs of each type of customer equally.

Q. OTHER THAN STATE REGULATORY COMMISSIONS, SUCH AS THE MINNESOTA PUBLIC UTILITIES COMMISSION, WHAT OTHER ENTITIES REGULATE THE NSP SYSTEM?

A. The NSP System is regulated primarily by three entities other than state regulatory commissions. The first is FERC. FERC is a federal independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The Energy Policy Act of 2005 gave FERC additional responsibilities. As part of that responsibility related to electric transmission, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Reviews the siting applications for electric transmission projects under limited circumstances;
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Enforces FERC regulatory requirements through imposition of civil penalties and other means; and
- Administers accounting and financial reporting regulations and conduct of regulated companies.

The second is NERC. NERC's primary role is to assure the reliability of the country's bulk transmission system. NERC does this by issuing and enforcing reliability standards which transmission operators, including the Company, are required to comply with; annually assessing seasonal and long-term reliability; monitoring the Bulk Electric System through system awareness; and educating, training, and certifying industry personnel. As the certified Electric Reliability Organization (ERO), NERC is subject to oversight by FERC.

Third is the Midwest Reliability Organization (MRO). MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO is one of eight regional entities in North America operating under authority from regulators in the United States through a delegation agreement with NERC, and in Canada through arrangements with provincial regulators. The primary purpose of MRO is to ensure compliance with reliability standards and perform regional assessments of the grid's ability to meet the demands for electricity. MRO audits the NSP Companies for compliance with NERC's reliability standards.

Q. PLEASE DESCRIBE MISO AND ITS ROLE WITH RESPECT TO THE NSP SYSTEM.

A. NSPM and NSPW are transmission-owning members of MISO. This means that while the NSP Companies own and maintain their transmission assets, MISO operates the NSP System, in conjunction with the transmission systems of the other 56 transmission owners. Furthermore, MISO establishes: (1) the process and rules for wholesale customers to access the NSP System on a non-discriminatory basis; (2) the annual transmission planning process for expanding or upgrading the regional transmission system, which includes the NSP System (i.e., MISO Transmission Expansion Plan (MTEP)); 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.

Q. PLEASE DESCRIBE THE DEPARTMENTS WITHIN THE TRANSMISSION ORGANIZATION AND THEIR KEY FUNCTIONS.

A. There are six different departments within the transmission organization and each department reports to the Senior Vice-President of Transmission. The key functions of these departments are as follows:

- Asset management is responsible for substation field engineering which includes routine and emergency maintenance and operational activities for all Xcel Energy substations. The organization also provides field implementation of certain NERC and Critical Infrastructure Protection (CIP) compliance activities, and "commissioning" new substation facilities. Commissioning of Xcel Energy substation facilities involves ensuring that our substation facilities meet the operational and reliability requirements of FERC and NERC as well as Xcel Energy. The Quality Assurance/Quality Control (QA/QC) process performed by Xcel Energy commissioning engineers and technicians thoroughly tests the equipment and control systems of our electric substations prior to energizing. This organization is also responsible for system sustainability. System sustainability provides, among other things, electric material and design standards for the design, construction, and maintenance of our transmission assets by interpreting industry standards such as the American National Standards Institute (ANSI). System sustainability is also responsible for developing Xcel Energy's reliability-centered maintenance programs that ensure the health and reliability of existing assets. These processes establish the baseline performance expected by our operations and maintenance organizations and confirm the performance for compliance standards.

- Transmission strategy and planning is responsible for: (1) life cycle planning, transmission system planning, and associated capital budgeting; (2) negotiating transmission service related contracts with generators, transmission owners, and distribution utilities; and (3) resolving wholesale customer transmissions service concerns. In addition, this organization manages Xcel Energy's participation in key regional projects throughout its service territory, as well as other regional projects on and adjacent to Xcel Energy's transmission systems, including the NSP System. This group is also responsible for Xcel Energy's policies and procedures in the competitive transmission acquisition processes pursuant to various requirements of FERC Order 1000. I serve as the Area Vice President for this organizational area.
- Field operations provides field services for construction, maintenance, and emergency repairs for transmission assets.
- Transmission portfolio delivery is responsible for managing capital projects, programs, and portfolios, including designing and engineering transmission assets, managing third-party contractors, and securing and managing transmission land rights.
- System operations is primarily responsible for the NERC Balancing Authority and Transmission Operations function for all Xcel Energy transmission systems, including the NSP System.
- Transmission business operations directs the transmission business unit's efforts pertaining to compliance with NERC CIP requirements and directs business performance achievement efforts.

Q. HOW IS THE COMMISSION INFORMED ABOUT TRANSMISSION PROJECTS ABSENT A RATE CASE FILING?

A. In November in odd numbered years, Xcel Energy along with other Minnesota transmission owners is required by Minn. Stat. § 216B.2425 to file a Biennial Transmission Projects Report. This report provides information on the status of the transmission system, including identifying possible solutions to anticipated inadequacies in the transmission system. In addition, the Company also files for Commission approval of Certificates of Need and Route Permits for certain new large transmission line projects or in some cases, rebuilds. Further, the Company is allowed to seek cost recovery for transmission line projects that have been granted a Certificate of Need through the TCR Rider. In these yearly TCR Rider filings, the Company provides updates on the status and current cost estimates for these transmission projects.

III. CAPITAL INVESTMENTS

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss capital budget trends for transmission from 2016 to 2019 and discuss major planned investments and key capital projects for 2020, 2021, and 2022. I will also provide details regarding how the transmission business unit develops its annual capital budget and correspondingly identifies and prioritizes transmission capital projects within the confines of the capital budget. Furthermore, I will discuss how transmission monitors and controls spending on capital projects as they move from approval through construction.

Q. GENERALLY SPEAKING, WHAT TYPE OF CAPITAL INVESTMENTS ARE MADE BY THE TRANSMISSION ORGANIZATION?

A. Our capital projects require investments in transmission line components, such as poles, conductors, gang-operated switches, and land rights for transmission line easements. They also include investments in substation components such as transformers, capacitor banks, reactors, circuit breakers, relay and communication equipment, remote terminals, and real property.

Our capital projects fall into two main types. The first are large capital projects that are often multi-year projects. These projects are capital intensive and are aimed at improving the transmission system; upgrading existing facilities to meet NERC compliance requirements and to accommodate new generation; replacing aging facilities; and making improvements to communication infrastructure and physical security.

In addition to these larger capital projects, Transmission also completes many smaller capital projects each year. These smaller projects comprise a majority of the total number of projects that we complete each year. However, these smaller projects make up only a minor part of our overall capital budget. Some examples of these smaller projects include replacement of one to two structures or cross-arms due to age, condition, or storm damage. Figure 1 and Figure 2 below depict this breakdown for 2020-2022 for NSPM and NSPW. As shown in these figures, our capital projects with greater than $10 million in capital additions make up 75 percent of our capital additions each year for NSPM and NSPW, but comprise only 23 percent of our total number of projects.

Figure 1

2020-2022 Total Number of Capital Projects

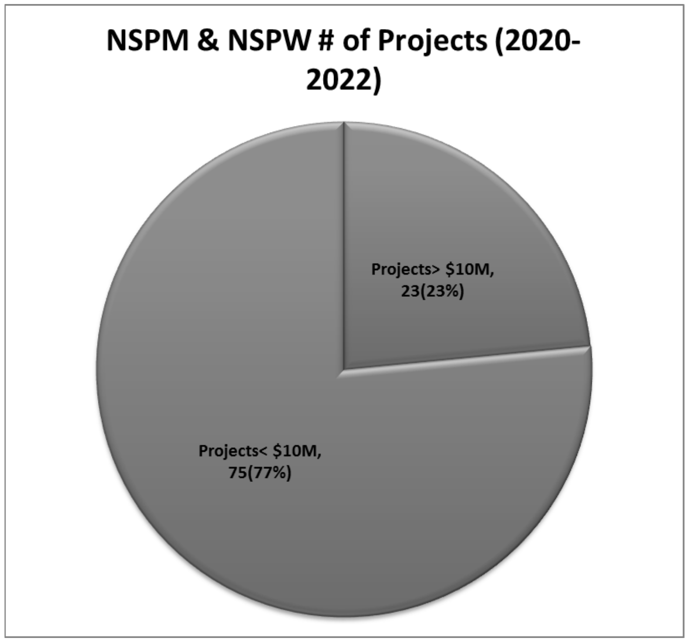
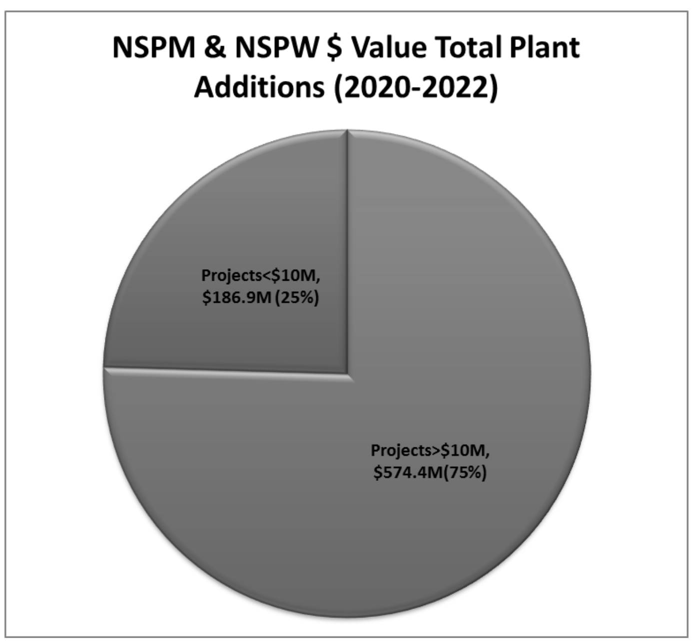


Figure 2

2020-2022 Total Budgeted Capital Additions



Q. ARE THERE ANY OTHER UNIQUE FEATURES OF TRANSMISSION'S CAPITAL INVESTMENTS?

A. Yes. Transmission's capital projects often require several years of development and construction before they are placed in-service as capital additions. This is because many of our transmission projects require multiple steps such as transmission study work and planning, route selection, initial design, permitting, final design, land acquisition, site preparation, and then construction. As a result, the Company may have capital expenditures for a particular project that span multiple years, with an in-service date several years after the first expenses are incurred.

Q. HOW DOES TRANSMISSION CATEGORIZE ITS CAPITAL ADDITIONS?

A. Our capital projects fall into six capital budget groupings depending on the main purpose of the project. These grouping are:

- Regional Expansion: This category includes major high voltage transmission line projects that are developed through the regional planning process and serve multiple needs including regional and local reliability and renewable energy outlet. Generally, these are multi-year initiatives and the types of projects for which the Company seeks a Certificate of Need and/or Route Permit from the Commission. This category also includes projects necessary to support economic development.
- Reliability Requirement: Reliability projects are constructed to ensure that the transmission system is complaint with all NERC reliability standards. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the Bulk Electric System. FERC, NERC, and regional reliability entities monitor and enforce compliance.

Any entity found non-compliant may be subject to fines of up to $1.2 million per day per violation. The Transmission organization is continually studying the transmission system to assess compliance with NERC standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation needs, and new generation interconnections to determine whether transmission upgrades are necessary.

- Asset Renewal: This category is primarily for managing the health and performance of transmission assets. The main goal is to ensure that critical assets including transmission lines, substations, and other related assets meet reliability and capacity requirements, while minimizing life-cycle costs. This includes planned replacement of aging transmission lines and substation equipment; unplanned replacement of lines or equipment damaged by storms; additions to, or replacement of, aging fleet vehicles and tools that support capital additions; and line relocations due to road projects.
- Interconnection: This category includes projects that the Company is required to construct under the FERC Open Access Transmission Tariff (OATT) to accommodate interconnection requests from generators, transmission lines, and new load.
- Communication Infrastructure: This category includes the fiber optic build-out on the transmission system to improve connectivity for all business areas. This category also includes required communication infrastructure upgrade projects to allow the digital transfer of Supervisory Control and Data Acquisition (SCADA) data and tele-protection services as telecommunication service providers are retiring the existing obsolete "frame relay" and analog connections. Reducing

dependencies on outside telecommunications providers improves system reliability.

- Physical Security and Resiliency: There are two critical aspects to this grouping of projects: physical security and grid resiliency. Physical security addresses physical threats to utility infrastructure, such as transmission lines and substation equipment. Grid resiliency addresses the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages; oftentimes by adding redundancy to our transmission system. This category also includes projects intended to address NERC standards related to physical security and grid resiliency.

Many of our capital additions serve multiple purposes, but for budgeting purposes, we classify the capital project according to its primary purpose.

B. Transmission Capital Budget Development and Management

1. *Reasonableness of Overall Budget*

Q. PLEASE MAKE THE BUSINESS CASE FOR TRANSMISSION'S CAPITAL PROGRAM.

A. Reliable and efficient electric service for our customers depends on a strong transmission system that is able to accommodate a diverse mix of generators. The capital investments made by the transmission business unit are necessary to allow the electricity generated by Company-owned and third-party generators to reach our customers. To maintain the reliability and health of the transmission system, the transmission organization has made and continues to make reasonable investments in maintaining existing facilities and building new transmission infrastructure to provide additional capacity as needed to integrate new generation. These investments ensure the reliable electric service that homes and businesses expect, while also supporting a competitive wholesale electricity market that allows access to low-cost generation across the MISO system.

Absent ongoing investments in our transmission system, we put the reliability and efficiency of this important system at risk. The transmission organization also recognizes that the Company's overall budget is limited and we seek to prioritize projects in a manner that achieves an appropriate balance in maintaining the health and reliability of our transmission system but also making long-term, cost-effective investments for our customers.

Q. HOW DOES TRANSMISSION ESTABLISH A REASONABLE CAPITAL BUDGET FOR A GIVEN YEAR?

A. The annual capital budget for transmission is based on collaboration between corporate management of the overall Company finances and the business needs that are identified by transmission. Company witness Mr. Gregory J. Robinson explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and the overall needs of the Company.

2. *Transmission's Capital Budgeting Process*

Q. CAN YOU PROVIDE A SUMMARY OF THE TRANSMISSION CAPITAL BUDGETING PROCESS?

A. Transmission employs a "bottom-up" budgeting process to identify the capital projects that we need to complete within a specific year for our business area. All of our transmission capital projects are executed under our Capital Project Governance Process. This governance process has policies and procedures in place that enable transmission to prioritize and balance our budget such that we appropriately allocate funds. Our capital budgeting process includes four main steps:

1. Identification of potential projects,
2. Vetting of potential projects,
3. Prioritization of potential projects, and
4. Rebalancing and reprioritization of projects based on corporate budget requirements.

a. New Project Identification

Q. WHAT IS THE FIRST STEP IN YOUR BUDGETING PROCESS?

A. We begin our budgeting process by identifying and assessing the potential work that is proposed for integration into the current five-year budget period. New projects must satisfy a clearly defined purpose and need. The criteria used to identify and assess transmission projects are based on the six capital budget groupings I discussed earlier. The budgeting process also takes into account existing projects that were previously approved based on the corporate governance approval requirements that Mr. Robinson describes. The annual budget is a very dynamic process where new project needs and financial requirements are prioritized against existing projects that most often take multiple years from initial budget approval to construction completion and close out.

Q. HOW ARE RELIABILITY REQUIREMENT PROJECTS IDENTIFIED?

A. NERC requires utilities to perform annual assessments of their transmission system for the 10-year planning horizon. The Company performs this annual assessment working through the Transmission Assessment and Compliance

Team (TACT), which is a group of transmission-owning utilities in Minnesota and surrounding states. NERC requires utilities to demonstrate plans to keep the transmission system within limits (voltage, thermal, and stability limits) throughout the 10-year planning period. These limits are set to ensure the reliability of the transmission system. TACT participants work together to analyze the transmission system for deficiencies (high voltage, low voltage, lines or transformers beyond their rated capability, etc.), and when deficiencies are identified, plans are created to manage the transmission system to stay within limits. To the extent that keeping the transmission system within limits requires a new capital investment—such as a transmission line or transformer upgrade to increase the capability of the transmission system—the timing of that needed upgrade is identified (i.e., the year the thermal overload shows up in the analysis is the year the project is needed) and a capital project is identified to address the issue. As part of the planning process, various system solutions are evaluated to meet the identified needs and planners select the alternative that provides the best long-term cost-effective solution to meet the NERC standard.

Q. HOW ARE REGIONAL EXPANSION PROJECTS IDENTIFIED?

A. As I mentioned earlier, the Company takes part in regional transmission planning efforts to identify needed Regional Expansion projects. The Company is involved with the CapX2020 initiative, which identified and constructed the CapX2020 group of projects. As I mentioned above, the CapX2020 initiative is now working on a study to determine what transmission improvements will be needed to meet the 2050 carbon reduction goals proposed by utilities and policy makers. The Company also takes part in

MISO's yearly MTEP which works with all MISO transmission owners and stakeholders to identify Regional Expansion projects.

Through these regional transmission planning processes, regional system needs are identified and possible solutions are developed and vetted. The solutions that best meet the long-term needs of the regional transmission system are then approved by the MISO Board of Directors in the MTEP process.

Q. HOW DO YOU IDENTIFY ASSET RENEWAL PROJECTS?

A. Our system sustainability group identifies facilities in need of replacement or refurbishment based on a variety of factors. For transmission lines, these factors include: the importance of a particular line to being able to reliably serve customers, the line's age and condition, and the line's reliability history. These factors receive different weights to determine which lines are in the greatest need of replacement. Generally speaking, those lines that will negatively affect the most customers if they fail are placed higher on the list for replacement. For substation assets, a similar matrix is used. The system sustainability group then uses these lists to determine the urgency of each replacement and identifies specific projects for possible inclusion in the budget.

Asset Renewal projects also include relocations required by road construction projects. We work with federal, state, and local highway and road departments to identify needed relocations.

Q. HOW DO YOU DEVELOP AN INITIAL LIST OF INTERCONNECTION PROJECTS FOR THE BUDGETING PROCESS?

A. Our transmission planning department gathers all available information from interconnection requests submitted to the Company, either internally, from other utilities, or from MISO who administers generation interconnections.

Q. DO YOU DEVELOP A BUDGET TO ACCOUNT FOR PREVIOUSLY UNIDENTIFIED INTERCONNECTION REQUESTS?

A. Yes. The Company typically receives interconnection requests year-round, some of which will require specific funding in years that were not previously planned for in our typical budget cycle. For the projects not accounted for in our typical budget cycle, the Company holds funding in a program called Interconnection Agreement (IA) Tariff Fund. The amount budgeted for this program is based on historical averages and known demand of Interconnection project requests. As the Company receives these previously unplanned requests, funding is made available from the IA Tariff Fund to a specific interconnection project as appropriate.

Q. HOW ARE COMMUNICATION INFRASTRUCTURE PROJECTS FIRST IDENTIFIED?

A. Our substation communication engineering group identifies and assesses projects based on a specific rubric that considers issues like Bulk Electric System criticality, past performance of systems currently in-service, O&M costs associated with existing leased connections, telecommunication companies phasing out certain technology, benefit to other business areas, and integration into existing Company-owned infrastructure. Based on this analysis, the substation communication engineering group identifies certain projects for possible inclusion in the transmission budget.

Q. HOW ARE PHYSICAL SECURITY AND RESILIENCY PROJECTS IDENTIFIED?

A. Physical Security projects are identified based on the 2015 NERC CIP-014-2 standard. In 2018, the Company performed a vulnerability analysis of our Bulk Electric System (100 kV and above) substations within the NSP System. The analysis identified critical facilities and physical security improvements at multiple BES substations throughout the NSP system and was validated by third-party review as is required by the NERC standard. After validation, each identified site is prioritized for possible inclusion in the budget. CIP-014 requires that the Company reevaluate our system every two years so we anticipate that this biennial study will continue to identify these capital projects as our transmission system evolves.

Grid Resiliency projects address the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages. For example, based on FERC Order 754, non-redundant equipment required to facilitate breaker operation was added, as a contingency event, to the NERC TPL-001-4 standard. System planning identifies projects annually as part of their TPL-001-4 study to remediate reliability impacts caused by contingencies for possible inclusion into the transmission budget.

b. Project Origination and Budget Approval

Q. AFTER THE LIST OF POSSIBLE CAPITAL PROJECTS IS DEVELOPED, WHAT IS THE NEXT STEP IN THE BUDGETING PROCESS?

A. The project originator develops a proposed statement of work for each project normally consisting of the proposed preliminary scope, project description, need and benefits description, alternatives and proposed option, desired completion date, consequences of not doing the project, and a basic electric circuit diagram.

Multi-disciplinary project teams are then assembled. These project teams have a diverse set of functional skills including financial management, project management, design and engineering, system operations, construction, siting and land rights, scheduling, vegetation management, and planning. The project teams develop a detailed preliminary scope and schedule for the project with supporting documentation. The project team may also prepare high-level cost estimates to assess alternatives and weigh proposed solutions against other alternatives. These estimates help determine the most reasonable electrical and financial solution to meet the identified transmission needs. The preliminary project scope for the preferred solution is entered into transmission's budgeting and forecast software tool, called Tamcasting.

Q. WHAT HAPPENS AFTER THE PRELIMINARY SCOPE IS DEVELOPED?

A. The proposed project is presented for preliminary scope approval at the regular occurring Constructability (C1) meeting. All projects must pass through this C1 gate before proceeding to the next project phase. At this C1 meeting, the project's preliminary scope is peer reviewed by employees from relevant functional areas of the transmission organization (including project management, engineering design, transmission planning, siting and land rights, construction, and operations). The objective of this meeting is to review and challenge the project need and the proposed preliminary scope while looking for fatal flaws or better solutions. Project alternatives are reviewed to determine whether the proposed solution is the most cost-effective and provides the most long-term value for our customers.

Approval at the C1 meeting allows the project to pass through the C1 gate to the next step in the process. Projects not approved at the C1 meeting are either cancelled or returned to the project origination phase for further need and preliminary scope development based on peer review feedback at the C1 meeting. The project may be re-presented at a future C1 meeting for approval.

Q. IF A PROJECT IS APPROVED AT A C1 MEETING, WHAT IS THE NEXT STEP?

A. The project proceeds to the budget estimate package phase. Based on the C1 approved preliminary scope, the project manager coordinates the development of a budget estimate by reviewing the project deliverables with the project team, identifying and documenting routing and design assumptions, conducting field visits, and collecting estimates generated by engineering, siting and land rights, construction, and vegetation management. In special circumstances, pre-construction work orders are generated for planning and development costs—such orders require immediate, out-of-cycle budget approval. The project group also begins to develop an outage plan, a project-specific safety plan and site security plan, and prepares a preliminary risk register. The project team then assembles the budget estimate package and presents it for approval as part of the annual budget process. This is referred to as the "Budget Approval" phase.

Q. WHAT ACTIVITIES TAKE PLACE IN THE BUDGET APPROVAL PHASE?

A. The Budget Approval phase involves the creation of transmission's annual budget and schedule for capital projects. This annual budget aligns with the budgeting and budget governance process that Mr. Robinson addresses in his testimony. Each business unit including transmission works closely with corporate financial performance and reporting to develop capital budgets.

Q. WHAT IS THE FIRST STEP IN THE BUDGET APPROVAL PHASE?

A. The first activity for transmission in the Budget Approval phase involves the project managers refreshing the cost estimates for previously approved projects as well as entering the new proposed project attributes, proposed monthly cash flows, and in-service dates into Tamcasting.

Q. ARE DIFFERENT LEVELS OF APPROVAL REQUIRED FOR LARGE CAPITAL PROJECTS?

A. Yes. Special consideration is given to Tier 1 projects. Tier 1 projects are those projects that cost between $10 million and $50 million and must receive discrete approval from the Investment Review Committee (IRC) (for projects over $10 million) or Financial Council (for projects over $20 million). Tier 1 projects in excess of $50 million must receive discrete approval from IRC, Financial Council, and the Board of Directors. Tier 2 and Tier 3 projects (less than $10 million) must receive portfolio approval by the Board of Directors. A project that receives these various approvals has "Financial Authorization to Proceed," which enables the project to advance into the project development phase.

c. Project Prioritization

Q. AFTER ALL POSSIBLE CAPITAL PROJECTS ARE PLACED IN TAMCASTING, WHAT IS THE NEXT STEP?

A. Our directors and managers, along with other key employees review all possible projects that are entered into Tamcasting and represent our proposed budget to determine which ones should be implemented and included in the transmission budget.

As many of our Regional Expansion and Reliability Requirement projects are multi-year projects, once these projects have commenced, it is difficult to halt or defund these projects in subsequent budget years. We do, however, examine all capital expenditures for a given year to determine whether they are necessary to carry out the final execution of those projects. As a result, these projects often receive higher priority in our budgeting process as they move forward toward completion. Similarly, given our MISO Tariff obligations, we do not have much latitude to deny specific Interconnection projects from being included in our budget.

After we determine the portion of our budget that is committed to these projects, we examine our remaining budget and determine how to prioritize the remaining proposed projects and previously planned projects. We prioritize those projects based on the risk and urgency of a particular project.

After a series of meetings to discuss all of the potential projects and the appropriate prioritization given funding availability, the result is an initial capital budget for transmission.

Q. AFTER THE INITIAL BUDGET IS DETERMINED, WHAT IS THE NEXT STEP?

A. Transmission's proposed capital budget then moves through the corporate budgeting process discussed by Mr. Robinson. Based on the corporate budgeting process, a higher or lower percentage of the Company's overall budget may be allocated to transmission depending on the priority of needs at the Company level. Once the corporate budgeting process is complete, transmission may be able to maintain its capital budget as proposed or it may need to adjust based on the thresholds established at a corporate level.

d. Reprioritization of Projects

Q. WHAT HAPPENS IF TRANSMISSION DOES NOT RECEIVE ALL OF ITS REQUESTED FUNDING?

A. The capital projects that transmission identifies as necessary in a particular year often exceed the budget thresholds established at a corporate level. When this occurs, our directors and managers reexamine our budget and reprioritize our capital projects based on the new thresholds. During the reprioritization process, we carefully evaluate all of the system risks associated with each of these budget reduction scenarios and reevaluate all mitigation plans that may mean a suboptimal operation of the transmission system but ensure our compliance with all mandated system reliability standards.

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT THAT WAS ELIMINATED FROM TRANSMISSION'S CAPITAL BUDGET BASED ON THIS REPRIORITIZATION?

A. Yes, a project called High Pressure Fluid Filled (HPFF) Minneapolis Upgrade was proposed for inclusion in our 2022 budget but it was deferred until 2023 due to budget reprioritization.

Q. IF YOU ARE ABLE TO DEFER THIS PROJECT, IS IT EVEN NECESSARY?

A. The HPFF Minneapolis Upgrade is needed but is not urgent and therefore can be delayed one year. The HPFF Minneapolis Upgrade project replaces the HPFF 115 kV underground transmission lines that serve a large portion of the downtown Minneapolis area. HPFF is a pipe-like underground transmission line where the conductors are insulated with oil-impregnated kraft paper and covered metal shielding (pipe). Inside the pipe the conductors are surrounded by a dielectric oil that is pressurized which prevents electrical discharges in the conductors' insulation. The fluid also transfers heat away from the conductors.

These HPFF lines, installed in the 1960s, are beyond their expected useful life and are showing signs of degradation and antiquation; however, they remain in-service and are functioning for their intended purpose. As with all aging assets failure is an eventual reality; however, predicting when that failure may occur and whether the failure will cause service disruption is difficult. An increased focus for maintaining these assets in recent years has allowed transmission the ability to defer this project until there is sufficient room in the budget for it to be executed.

Q. DOES THIS BUDGETING PROCESS THAT YOU HAVE DESCRIBED ENSURE THAT TRANSMISSION'S CAPITAL ADDITIONS ARE REASONABLE AND NECESSARY IN EACH YEAR OF THIS MULTI-YEAR RATE PLAN?

A. Yes. This budgeting process results in a reasonable budget that is representative of the capital investments needed to maintain the reliability of the transmission system used to provide electric service to our customers, provide necessary upgrades to the regional transmission system, comply with

NERC reliability requirements and other policy drivers, meet system capacity needs, and ensure the health of existing assets.

e. Project Performance

Q. PLEASE EXPLAIN THE PROCESS YOU FOLLOW TO MANAGE CAPITAL EXPENDITURES AFTER BUDGET APPROVAL.

A. From a financial perspective, capital projects are reviewed on a monthly basis after approval to compare the monthly budget to actual funds spent. We perform a monthly project forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. Through this process, the entire transmission project portfolio is reviewed and consolidated each month. Any variances are immediately addressed. All projects that indicate they may be outside of allowed variances are reevaluated and assessed internally by the transmission business unit and may be escalated to the corporate level. For larger projects, greater than or equal to $10 million, we adhere to the corporate guidelines to seek "re-approval" of projects outside allowed variances.

Review is also performed to compare year-to-date actual performance with year-to-date and year-end forecasts. Deviations are identified and recommendations to meet financial targets are reviewed and approved. Changes are reported to the financial performance and planning group, which monitors capital spending. The Transmission business unit is expected to manage its capital additions to its capital budget once that budget has been developed, fully-vetted, and approved. The budgeting process and accountability tools allow us to do so.

C. Capital Investment Trends for 2016 to 2019

Q. FOR 2016-2018, WHAT WERE THE PRIMARY DRIVERS FOR TRANSMISSION'S CAPITAL ADDITIONS?

A. From 2016 to 2018, our capital investments were focused on in-servicing several large Regional Expansion projects. This included the remaining CapX2020 projects, which were completed in 2017, as well as the Badger Coulee Project, a MISO designated Multi-Value Project, that was completed in 2018 (also referred to as the La Crosse – Madison Project). Apart from these large Regional Expansion projects, transmission also completed work on several smaller Reliability Requirement projects. These included the Bluff Creek 115 kV Substation and the Gleason Lake Substation projects in Minnesota and the Minot Load Serving and Prairie Substation expansion in North Dakota. Also during this period, Transmission continued to make investments in Asset Health projects such as Storm & Emergency – NSP Lines and our End-of-Life-Replacement programs. In 2016, there was a storm event near Rogers, Minnesota that damaged approximately 10 miles of two 345 kV lines in a shared corridor. This storm restoration project contributed to $16.3 million in plant additions to our Asset Renewal category during this period.

Q. FOR 2016 TO 2018, HOW DID YOUR CAPITAL INVESTMENTS BREAK INTO CAPITAL BUDGET GROUPINGS?

A. Table 1 below shows the breakdown of capital expenditures by each capital budget grouping for 2016 to 2018.

Table 1

2016-2018 Capital Expenditures (Excludes AFUDC) (Dollars in Millions)			
NSPM and NSPW Transmission – Business Unit	**2016 Actual**	**2017 Actual**	**2018 Actual**
Regional Expansion	$85.5	$76.8	$60.1
Reliability Requirement	$45.0	$53.9	$72.5
Asset Renewal	$62.7	$67.5	$73.3
Communication Infrastructure	$7.3	$3.3	$1.9
Interconnection	$10.2	$1.6	$10.8
Physical Security and Resiliency	$4.6	$17.6	$16.5
Totals	**$215.3**	**$220.7**	**$235.1**

Table 2 below shows the breakdown of capital additions by each of the six capital budget groupings for 2016 to 2018. The amounts presented in my testimony include costs recovered or intended to be recovered through the TCR Rider. Mr. Halama will discuss the TCR Rider in greater detail. I am including these amounts here as these projects are part of our overall transmission capital budget.

Table 2

2016-2018 Capital Plant Additions (Includes AFUDC) (Dollars in Millions)			
NSPM and NSPW Transmission – Business Unit	**2016 Actual**	**2017 Actual**	**2018 Actual**
Regional Expansion	$76.0	$74.1	$183.6
Reliability Requirement	$74.0	$56.9	$94.0
Asset Renewal	$56.5	$53.9	$73.2
Communication Infrastructure	$2.0	$8.7	$4.5
Interconnection	$5.7	$7.3	$9.8
Physical Security and Resiliency	$7.2	$16.9	$14.4
Totals	**$221.3**	**$217.7**	**$379.4**

Q. CAN YOU EXPLAIN THE INCREASE IN CAPITAL ADDITIONS IN 2018 AS COMPARED TO 2016 AND 2017?

A. Yes. This increase is primarily due to the in-servicing of one large Regional Expansion project in 2018 – the Badger Coulee Project. The Badger Coulee Project is a 180-mile 345 kV transmission line from La Crosse, Wisconsin to Madison, Wisconsin. In 2018, we also placed in service a number of Reliability Requirement projects including the Gleason Lake Substation and Pomerleau Lake Substation projects in Minnesota and the Minot Load Serving project in North Dakota. From 2016 to 2018, we also made increasing investments in the Physical Security and Resiliency category to make necessary physical security upgrades at nine of the Company's substations in Minnesota.

Q. WHAT ARE THE COMPANY'S FORECASTED CAPITAL ADDITIONS FOR 2019?

A. In 2019, we are forecasting approximately $165.5 million in capital additions which is a substantial decrease from our 2018 actuals of $379.4 million.

Q. WHY ARE TRANSMISSION CAPITAL ADDITIONS FOR 2019 SIGNIFICANTLY LOWER THAN 2018?

A. This decrease is due to lower capital additions for Regional Expansion projects and Reliability Requirement projects. As I mentioned above, the CapX2020 projects and Badger Coulee were all placed in service by 2018 and our next large Regional Expansion project, Huntley–Wilmarth, will not be placed in service until 2021. Also, due to the timing of in-service dates, there is also only one Reliability Requirement project that will be placed in-service in 2019, the Maple River to Red River project, which has a plant addition of $19.6 million. As a result, our capital additions in this category are lower in both 2019 and 2020 as compared to past years.

D. Overview of Capital Investments for 2020 to 2022

Q. WHAT ARE YOUR CAPITAL FORECASTS FOR 2020-2022 BY CAPITAL BUDGET CATEGORY?

A. Table 3 and Table 4 (Figure 3) below provide both planned capital expenditures and additions for 2020 to 2022.

Table 3

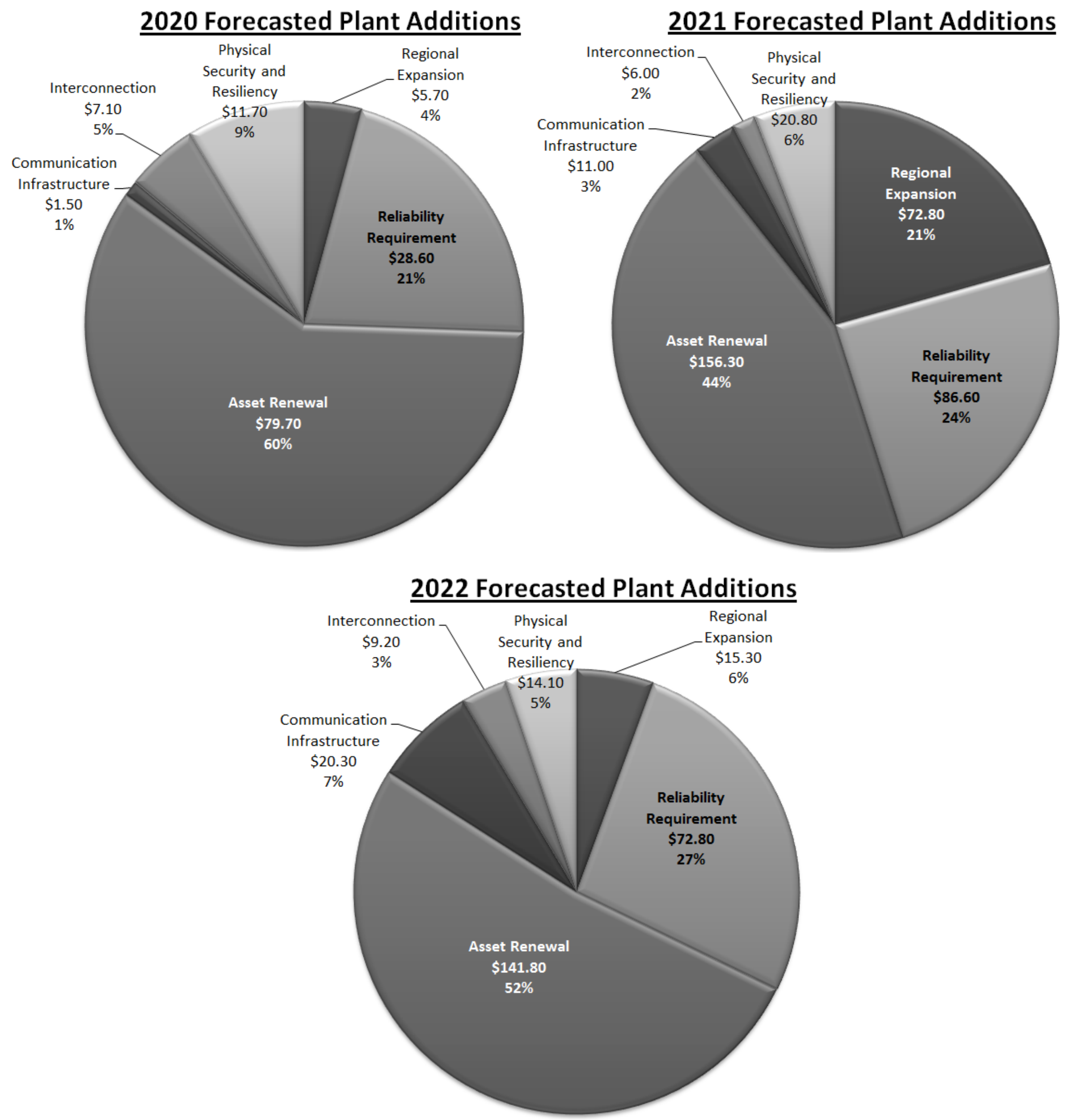
2020-2022 Forecasted Capital Expenditures (Dollars in Millions)			
NSPM & NSPW Transmission – Business Unit	**2020**	**2021**	**2022**
Regional Expansion	$39.1	$73.4	$39.1
Reliability Requirement	$57.4	$108.8	$93.5
Asset Renewal	$80.7	$157.8	$174.8
Communication Infrastructure	$1.3	$10.8	$20.6
Interconnection	$7.2	$7.4	$21.0
Physical Security and Resiliency	$11.8	$19.8	$13.9
Totals	**$197.5**	**$377.9**	**$363.0**

Table 4

2020-2022 Forecasted Capital Plant Additions (Dollars in Millions)			
NSPM & NSPW Transmission – Business Unit	**2020**	**2021**	**2022**
Regional Expansion	$5.7	$72.8	$15.3
Reliability Requirement	$28.6	$86.6	$72.8
Asset Renewal	$79.7	$156.3	$141.8
Communication Infrastructure	$1.5	$11.0	$20.3
Interconnection	$7.1	$6.0	$9.2
Physical Security and Resiliency	$11.7	$20.8	$14.1
Totals	**$134.3**	**$353.5**	**$273.5**

Figure 3

(Dollars in Millions)



Q. PLEASE EXPLAIN WHY CAPITAL INVESTMENTS ARE INCREASING OVER THE TERM OF THE MULTI-YEAR RATE PLAN?

A. During the term of the multi-year rate plan, we will be increasing our investments in Reliability Requirement and Asset Renewal projects. This includes increasing our investments in line rebuild and refurbishment projects that are necessary to maintain the health of our aging assets. We will also be making increasing investments in our Communication Infrastructure to privatize Xcel Energy's communication network infrastructure across the NSPM and NSPW service territories for SCADA, teleprotection, and remote engineering access to reduce our exposure to cybersecurity threats from the publicly available service provided by third-party telecommunication providers. Finally, due to the number of interconnection requests currently pending in the MISO queue, our investments in Interconnection projects will also increase from 2020 to 2022. On the other hand, our investments in Regional Expansion projects are declining during the term of the multi-year rate plan as compared to recent years. The exception to this decline is in 2021 when the Huntley–Wilmarth Project will be placed in service.

Q. WHAT KEY PROJECTS WILL YOU BE INVESTING IN OVER THIS TIME PERIOD?

A. A large portion of our capital budget from 2020 to 2022 will be devoted to Asset Renewal projects in Minnesota, Wisconsin, and the Dakotas. Specifically we will be rebuilding large segments of existing transmission lines that have been experiencing poor line performance due to their age and condition. Also during these years we will be completing construction of the Huntley–Wilmarth Project and a Reliability Requirement project in Wisconsin – the Bayfield Loop Project.

Q. WHY IS IT NECESSARY FOR TRANSMISSION TO MAKE INVESTMENTS IN WISCONSIN LIKE THE BAYFIELD LOOP PROJECT?

A. The reliability of the NSP System depends not just on the reliability of the transmission facilities located in the State of Minnesota but, due to the integrated nature of the grid, the facilities located in other states. As a result, it is important to make the necessary investments across all portions of the NSP System.

Q. HOW DO TRANSMISSION CAPITAL INVESTMENTS IN 2020 TO 2022 COMPARE TO HISTORIC TRENDS?

A. Our 2016 through 2022 capital expenditures and capital additions are set forth in Table 5 and Table 6 below. As these tables illustrate, our capital additions for 2020 are lower than historic amounts, due to the timing of the in-service dates for several large projects, but our capital additions for 2021 and 2022 are in line with historic trends.

Table 5

2016-2022 Actual and Forecasted Capital Expenditures (Includes AFUDC) (Dollars in Millions)							
NSPM and NSPW Business Unit - Transmission	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**
Regional Expansion	$85.5	$76.8	$60.1	$12.8	$39.1	$73.4	$39.1
Reliability Requirement	$45.0	$53.9	$72.5	$44.7	$57.4	$108.8	$93.5
Asset Renewal	$62.7	$67.5	$73.3	$108.6	$80.7	$157.8	$174.8
Communication Infrastructure	$7.3	$3.3	$1.9	$1.0	$1.3	$10.8	$20.6
Interconnection	$10.2	$1.6	$10.8	$7.3	$7.2	$7.4	$21.0
Physical Security and Resiliency	$4.6	$17.6	$16.5	$12.7	$11.8	$19.8	$13.9
Totals	**$215.3**	**$220.7**	**$235.1**	**$187.2**	**$197.5**	**$377.9**	**$363.0**

Table 6

2016-2022 Actual and Forecasted Capital Plant Additions (Includes AFUDC) (Dollars in Millions)							
NSPM and NSPW Business Unit – Transmission	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**
Regional Expansion	$76.0	$74.1	$183.6	$19.1	$5.7	$72.8	$15.3
Reliability Requirement	$74.0	$56.9	$94.0	$41.3	$28.6	$86.6	$72.8
Asset Renewal	$56.5	$53.9	$73.2	$79.7	$79.7	$156.3	$141.8
Communication Infrastructure	$2.0	$8.7	$4.5	$0.7	$1.5	$11.0	$20.3
Interconnection	$5.7	$7.3	$9.8	$8.9	$7.1	$6.0	$9.2
Physical Security and Resiliency	$7.2	$16.9	$14.4	$15.9	$11.7	$20.8	$14.1
Totals	**$221.3**	**$217.7**	**$379.4**	**$165.5**	**$134.3**	**$353.5**	**$273.5**

Q. WHAT KINDS OF CHANGES COULD OCCUR THAT MAY LEAD TO A RE-PRIORITIZATION OF YOUR INVESTMENTS AND CHANGE THE PERCENTAGES THAT YOU INVEST IN EACH CAPITAL BUDGET GROUPING DURING THE TERM OF THE MULTI-YEAR RATE PLAN?

A. There are several reasons why we may need to reprioritize capital investments in a particular year or over several years. For example, the recent severe weather incidents have resulted in renewed industry-wide focus to address the aging infrastructure of the grid. As shown in Table 7 this focus is reflected in transmission's budget during the multi-year rate plan period which has increasing investments in our Asset Renewal group.

Q. WHY IS THE ABILITY TO CHANGE THESE INVESTMENT PERCENTAGES IMPORTANT TO THE COMPANY AND YOUR CUSTOMERS?

A. When we make adjustments to our capital investment plans, we do so to better serve our customers' and our Company's most urgent needs in the most cost-effective way. When the need arises to accelerate a project or develop a new project, we assess the situation to make sure we are doing so for the right reasons and in a prudent way. Similarly, we assess potential project delays or cancellations to make sure we are still meeting business and customer needs in a reasonable way.

Q. EVEN IF YOUR INVESTMENT PERCENTAGES CHANGE FROM THE CURRENT FORECAST, WILL TRANSMISSION STILL WORK TO MANAGE ITS OVERALL CAPITAL INVESTMENTS WITHIN ITS OVERALL BUDGET?

A. Yes. While our investments in particular capital budget groupings may change to address unanticipated issues, ultimately, we will invest as necessary to meet our overall goals of safe and reliable transmission of energy for our customers.

Q. WHAT DO YOU CONCLUDE ABOUT THE TRANSMISSION 2020 – 2022 CAPITAL INVESTMENT FORECASTS?

A. I conclude that our capital forecasts represent an accurate and reasonable picture of our investments over these years. Therefore, these forecasts can be relied on to set just and reasonable rates for our customers.

E. Major Planned Investments for 2020 to 2022

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony discusses the major planned investments transmission anticipates in 2020 through 2022. The State of Minnesota jurisdictional figures for each capital addition are included as Exhibit___(IRB-1), Schedule 2.

Q. HOW DID TRANSMISSION IDENTIFY ITS MAJOR PLANNED INVESTMENTS OVER THE PLAN PERIOD?

A. To identify these investments, we looked for those unique projects that require a greater than normal quantity of transmission resources to complete and that contribute to our overall major planned investments.

Q. WHAT MAJOR PLANNED INVESTMENTS DOES TRANSMISSION ANTICIPATE COMPLETING OVER THE PERIOD OF THIS MULTI-YEAR RATE PLAN?

A. As depicted in Table 7, we anticipate undertaking four major planned investments between 2020 and 2022. These projects include one Regional Expansion project, the Huntley–Wilmarth Project, two Asset Health projects, NSPW Major Line Rebuild and NSPM Major Line Rebuild, and one Reliability Requirement project, the Bayfield Loop Project.

Table 7

Transmission Major Planned Investment Projects

	Capital Additions (Dollars in Millions)		
	2020	**2021**	**2022**
Huntley–Wilmarth 345 kV Project	$3.5	$72.8	$1.3
NSPM Major Line Rebuild	$0.0	$12.6	$48.5
NSPW Major Line Rebuild	$32.1	$33.7	$15.0
Bayfield Loop Project	$0.0	$0.0	$39.8

These projects will continue over multiple years, with portions of the projects placed in-service as they are put to use each year. These major planned investments, as well as the additional key capital projects we anticipate completing in 2020, 2021, and 2022 are discussed in more detail below.

Q. DOES THE COMPANY PLAN TO RECOVER ANY OF THESE PROJECTS THROUGH THE TRANSMISSION COST RECOVERY (TCR) RIDER?

A. Yes. The Huntley–Wilmarth 345 kV Project will be recovered through the TCR Rider. I am including this project here as it also qualifies, for ratemaking purposes, as major planned investments during the plan period. Mr. Halama will provide additional information on TCR Rider recovery of this project.

F. Key Capital Additions for 2020 to 2022

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I describe the main projects under each of the capital budget groupings I noted earlier. Unless otherwise stated, all dollar figures are at the NSPM and NSPW level. The State of Minnesota jurisdictional amounts for these capital additions are included in Exhibit___(IRB-1) Schedule 2.

1. Regional Expansion Projects

Q. WHAT ARE THE KEY REGIONAL EXPANSION PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. There are two key Regional Expansion projects that will be placed in-service between 2020 and 2022: (1) the Huntley–Wilmarth 345 kV Project; and (2) the Google Data Center Project.

Q. DESCRIBE THE HUNTLEY–WILMARTH 345 KV PROJECT.

A. The Huntley–Wilmarth 345 kV Project is a joint project between Xcel Energy and ITC Midwest and involves the construction of an approximately 50 mile, 345 kV transmission line in southern Minnesota and associated substation modifications. The transmission line will connect Xcel Energy's Wilmarth

Substation, located north of Mankato, and ITC's Huntley Substation, located south of Winnebago. The project will also include modifications at both the Huntley and Wilmarth substations to accommodate the new 345 kV transmission line.

The Huntley–Wilmarth Project is needed to reduce congestion on the transmission grid in southern Minnesota and northern Iowa to deliver low-cost electricity to consumers from generation facilities in the area, including wind farms. The project was studied, reviewed, and approved by MISO as a Market Efficiency Project (MEP) in December 2016 as MISO found that the project will reduce congestion on the transmission system, which will improve the efficiency of MISO's energy markets resulting in lower wholesale energy costs. The Commission granted a Certificate of Need and Route Permit for the Huntley–Wilmarth Project on August 5, 2019.[1]

The project is currently in the final design and land acquisition phase and will be placed in-service in December 2021, which is the project's MISO designated in-service date. The project has total plant additions of approximately $78.5 million ($0.9 million in 2019; $3.5 million in 2020; $72.8 million in 2021; $1.3 million in 2022).

Q. DESCRIBE THE GOOGLE DATA CENTER PROJECT.

A. The Company has negotiated several agreements with affiliates of Google LLC that are intended to help bring a new Google data center to the City of

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[1] *In the Matter of the Application of Xcel Energy and ITC Midwest LLC for a Certificate of Need and for a Route Permit for the Huntley–Wilmarth 345-kV Transmission Line Project*, ORDER FINDING ENVIRONMENTAL IMPACT STATEMENT ADEQUATE, GRANTING CERTIFICATE OF NEED, ISSUING ROUTE PERMIT, AND REQUIRING ADDITIONAL ANALYSIS, Docket Nos. E002, ET-6675/CN-17-184, TL-17-185 (Aug. 5, 2019).

Becker, Minnesota. If the project moves forward, it would generate at least $600 million in capital investment by Google and presents an opportunity to be one of the largest private economic development endeavors in central Minnesota. To facilitate the development of the new data center, the Company sought and received approval from the Commission for several agreements, associated cost recovery, and certain tariff amendments and waivers that would enable the Company to provide retail electric service at transmission voltage to the new Google data center.[2]

Among the several agreements, the Company executed an Interconnection Agreement for Retail Electric Service at Transmission Voltage (IA), which provides the terms and conditions for the Company's build-out of certain transmission voltage facilities to support interconnection of the Google data center. The IA provides different transmission voltage configurations to support varying amounts of data center load in line with the customer's issuance to the Company of a "Notice to Construct," after which the Company is obligated to construct the necessary facilities at its cost. Should the IA be terminated prior to the conclusion of the 10-year IA period, Google would make a termination payment to the Company equivalent to the net book value of the transmission facilities as of the date of termination.

The Company also requested and received approval of a one-time waiver from the Company's General Time-of-Day Service Tariff requiring that a customer bear the cost of interconnection upgrades required to serve the customer. Rather than recover these costs directly from Google via a contribution in aid

[2] *In the Matter of the Pet. by N. States Power Co. d/b/a Xcel Energy for Approval of Contracts and Ratemaking Treatment for Provision of Elec. Serv. to Google's Data Center Project*, ORDER APPROVING PETITION WITH CONDITIONS, Docket Nos. E002/M-19-39 and E002/M-19-60 (July 15, 2019).

of construction (CIAC), the Company requested – and the Commission granted – authorization to seek recovery of these costs in a future rate case.[3]

The project has total plant additions from 2020-2022 of approximately $15.3 million ($1.2 million in 2020; $14.1 million in 2022).

Q. WHY IS THE GOOGLE DATA CENTER PROJECT CLASSIFIED AS A REGIONAL EXPANSION PROJECT?

A. In addition to large regional infrastructure, our Regional Expansion Projects also include those projects driven by economic development needs, which is the primary driver for the Google Data Center project.

2. Reliability Requirement Projects

Q. WHAT IS DRIVING THE COMPANY'S INVESTMENTS IN RELIABILITY REQUIREMENT PROJECTS?

A. NERC develops and enforces reliability standards on all transmission owners, operators, and users. The Company performs transmission planning studies to identify necessary upgrades to the system to ensure compliance with NERC standards. Through these studies, transmission planners evaluate all various alternatives to meet the identified electrical needs for the system and select the option that considers the incremental impact of the project for future needs in the area and best meets the long-term electrical needs of the area in a cost-effective manner.

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[3] *Id*. at 23.

Q. WHAT WOULD BE THE IMPACT OF EITHER FOREGOING OR DEFERRING A RELIABILITY REQUIREMENT PROJECT?

A. If a Reliability Requirement project is either deferred or cancelled, the Company could be found to be in violation of NERC reliability standards. In addition, as NERC standards are in place to promote the health and reliability of the transmission system. Deferring or foregoing a necessary Reliability Requirement project could impact system reliability.

Q. WHAT ARE THE KEY RELIABILITY REQUIREMENT PROJECTS THAT TRANSMISSION WILL PLACE IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. There are five key Reliability Requirement projects and programs that will be placed in-service between 2020 and 2022:

- Bayfield Loop Project;
- Wilson Substation Conversion Project;
- Hibbing Taconite 500 kV Project;
- TACT Project; and
- NSPM Galloping Conductors program.

Q. PLEASE DESCRIBE THE BAYFIELD LOOP PROJECT.

A. The Bayfield Loop Project, which is also referred to as the Bayfield Second Circuit Transmission Project, is needed to improve system reliability by constructing a second 34.5 kV transmission line and two new substations in the Bayfield Peninsula area of Wisconsin. Depending on the route selected by the Public Service Commission of Wisconsin (PSCW), the proposed new transmission line would extend approximately 19 to 26 miles, and would connect the two new substations: the Fish Creek Substation, located approximately four miles west of Ashland, Wisconsin, and Pikes Creek Substation, located approximately two miles west of Bayfield, Wisconsin.[4] The project will increase electric reliability and reduce power outages across the Bayfield Peninsula by providing voltage support and a second source of power to the east side of the Bayfield Peninsula. The proposed 34.5 kV transmission line is called the "second circuit" or "second source" because there is an existing 34.5 kV line extending to Bayfield.

This project is currently scheduled to be placed in service in 2022. The project has total plant additions of approximately $39.8 million, all to be added in 2022.

Q. PLEASE DESCRIBE THE WILSON SUBSTATION CONVERSION PROJECT.

A. The Wilson Substation Conversion Project converts the existing Wilson Substation, which is located in Bloomington, Minnesota, from a 115 kV straight bus configuration to a breaker-and-a-half design. The project provides for the installation of six 115 kV breaker-and-a-half rows, thereby allowing for the addition of a fourth distribution transformer. This additional transformer will address load growth and distribution reliability concerns in the area, all without the need to expand the existing substation footprint. The existing transformers will connect to the new breaker-and-a-half positions via underground cable. The project also includes the installation of a new 24-foot by 80-foot electrical equipment enclosure (EEE) to the west of the existing EEE, which is required to accommodate the controls for the new equipment. Following completion of the project, the substation will be able to

[4] *Application of N. States Power Co.-Wisc. for a Certificate of Auth. to Construct the Bayfield Second Circuit Transmission Project, to be Located in Bayfield Cnty., Wisc.*, PSCW Docket No. 4220-CE-182.

accommodate maintenance outages to service the nine terminations in the substation (five lines, three distribution transformers, and one capacity bank).

The new substation design also requires the Company to reconfigure four existing transmission lines that terminate at Wilson Substation. The transmission line reconfigurations also require relay and control equipment upgrades at the Black Dog, Nine Mile Creek, and East Bloomington substations.

The project has total plant additions of approximately $22.7 million. The Company plans to complete the relay upgrades, control equipment, and setting upgrades at the Black Dog, Nine Mile Creek, and East Bloomington Substations in 2020 with a plant addition of $1.2 million. Then in 2021, the Company will complete all transmission line reconfigurations, along with the physical expansion and electrical construction work at Wilson Substation that will result in a plant addition of $21.6 million.

Q. PLEASE DESCRIBE THE HIBBING TACONITE (HIBTAC) 500 KV PROJECT.

A. The Hibbing Taconite 500 kV Project includes the removal, replacement, and relocation of approximately 10 miles of an existing 500 kV line that is located on Cleveland-Cliffs, Inc.'s land where HibTac has mining operations. The license agreement with the mine that granted Xcel Energy the right to construct and maintain the 500 kV line on the mine property also gave the mine the right to request relocation of the line. We are in the process of extending and revising the license agreement with Cleveland-Cliffs to relocate the line elsewhere on HibTac mining land.

This project is in the engineering stage and is nearing the end of the siting and land rights negotiations with the mine and surrounding landowners. The Company will seek a minor route alteration from the Commission for this relocation, and material purchases are expected to take place at the end of 2020 with construction planned to take place during 2021. This project places $15.54 million of plant in-service in 2021.

Q. WHY IS THE COMPANY REQUIRED TO PAY FOR THIS PROJECT INSTEAD OF THE CUSTOMER?

A. The license agreement for this portion of the 500 kV line included a condition that stated that after the first 15 years of the license agreement the costs for relocating the 500 kV line would be borne by the Company rather than HibTac.

Q. PLEASE DESCRIBE THE TACT PROJECT.

A. NERC requires utilities to perform annual assessments of their transmission system for the 10-year planning horizon. The Company performs this annual assessment by its participation on the Transmission Assessment and Compliance Team (TACT), which is a group of transmission-owning utilities in Minnesota and surrounding states. NERC requires utilities to demonstrate plans to keep the transmission system within specified voltage, thermal, and stability limits throughout the 10-year planning period. TACT participants work together to analyze the transmission system for deficiencies (high voltage, low voltage, lines or transformers beyond their rated capability, etc.) and to ensure compliance with NERC Standard TPL-001-4. The TACT studies the performance of the system using 1-year, 5-year, and 10-year future models. When deficiencies are identified, TACT creates a plan to manage the transmission system to stay within the specified limits. The TACT typically finalizes its annual study in January or February of each year.

The Company established the TACT Project program to allocate resources necessary to address reliability issues on the NSP System that are required as a result of the annual TACT studies.

For both NSPM and NSPW this project has total plant additions of approximately $20.0 million ($6.8 million in 2021; $13.2 million in 2022).

Q. PLEASE DESCRIBE THE NSPM GALLOPING CONDUCTORS PROGRAM.

A. The NSPM Galloping Conductors program encompasses projects that will mitigate line galloping on circuits identified on the NSP System that have shown vulnerability to line galloping. Transmission line galloping is the high-amplitude, low-frequency oscillation of overhead power lines as a result of certain wind conditions. The movement of the wires occurs most commonly in the vertical plane, although horizontal or rotational motion is also possible. The oscillations can sometimes cause the phase conductors to come too close to each other, causing flashover and occasional outages. Though rare, persistent galloping oscillations can cause fatigue to the conductor or fastening equipment securing the conductor or insulator to a structure, resulting in a mechanical failure.

The scope for projects in this program includes either the installation of anti-galloping devices or installing an anti-galloping conductor. In particularly vulnerable segments of a transmission circuit, a combination of both mitigation methods can be deployed in different segments of a single circuit.

The Company has identified a total of six discrete planned projects for a total $10.7 million in plant additions from 2020-2022 ($9.0 million in 2021; $1.6 million in 2022).

3. Asset Renewal Projects

Q. WHAT ARE THE PRIMARY ISSUES FACING TRANSMISSION RELATED TO ASSET RENEWAL?

A. Our organization is charged with maintaining a large and aging transmission infrastructure. In fact, in Minnesota more than 3,317 miles of transmission line was placed in-service during the 1960s and 1970s. While transmission facilities generally have long life spans, these facilities do not last forever. The Company examines both the condition and performance of our aging facilities to determine which facilities are in greatest need of replacement. We also prioritize replacement of aging facilities based on which facilities are most likely to fail and then which equipment will have the biggest impact to the transmission system when it does fail. Taking into account these factors helps us to prudently leverage our investment in our existing assets while still maintaining a reliable system. In addition to replacements due to age and condition, we must also make investments to replace facilities damaged by storms or other weather events.

Q. WHAT ARE THE KEY ASSET RENEWAL PROGRAMS AND PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. There are eight key Asset Renewal programs and one key Asset Renewal project that will be placed in-service between 2020 and 2022:

- NSPM and NSPW Major Line Rebuild program, which includes the West St. Cloud – Black Oak Rebuild Project;
- NSPM and NSPW Major Line Refurbishment program;
- Numerous End of Life Replacement (ELR) programs, including:
  - NSPM and NSPW Relay ELR program;
  - NSPM and NSPW Line ELR program;
  - NSPM Nuclear Substation ELR program; and
  - NSPW Substation Breaker ELR program.
- NSPM and NSPW Storms & Emergencies (S&E) Line program;
- Transmission UAV Flights program; and
- Tools and Equipment.

Q. PLEASE DESCRIBE THE NSPM/NSPW MAJOR LINE REBUILD PROGRAM.

A. The Major Line Rebuild program for NSPM and NSPW represents a group of projects that rebuild large segments of transmission lines on the NSP System that have a concentrated number of defects that contribute to poor line performance. These projects are typically required either because the existing line circuits are at risk for increased outage frequency or because the number of structural defects on the circuit makes it unreasonable to refurbish only the defective portions. A rebuild project scope requires complete wreck-out/removal of the physical line assets, which are then replaced with new line assets (structures, conductor, switches, etc.) either within the existing right-of-way (ROW) or with minor, targeted right-of-way expansion to accommodate outage constraints and safe construction practices.

The Company performs various types of assessments on the transmission line facilities at different points in time. Our construction department does comprehensive inspections to one-twelfth of all wood poles on an annual basis and does foot patrol inspections of one-sixteenth of all transmission line circuits annually. In addition, helicopter inspections of all FAC-003 (200 kV and above) transmission line facilities are performed on an annual basis. In these assessments, the Company identifies those transmission lines that require rebuilding, and specific projects are subsequently developed and prioritized using the Company's Line Prioritization Matrix, which is a tool developed by the transmission line performance group that uses internal and external information to quantitatively rank each transmission circuit. Each line is scored and ranked against each other incorporating the following drivers:

- Importance
    - What happens if the circuit has an outage
    - Operational concerns
    - Design concerns
- Reliability
    - Frequency of outages
    - Duration of outages
    - Benchmarking rating
- Condition Assessment
    - Incorporates two scoring groups
        - Field Engineer's Field Assessment
        - Transmission Asset Management System (TAMS) Identified Defects
            - Defect count and severity
            - Repair cost estimates

Through the assessment process, the Company may identify defective line circuits requiring a full rebuild as early as five years before the rebuild is needed. However, we typically budget lines for this program only two to three years in advance because upgrades in the system area, storms and emergencies, and changing system needs may alter the overall asset health score for identified lines beyond the two- to three-year window. The Company identifies, budgets for, and develops specific projects during our annual budget process and on the basis of the total asset health score of the line as determined by the Line Prioritization Matrix. These individual projects are then prioritized against the rest of the planned transmission capital portfolio. Lastly, the Company budgets for projects in the three- to five-year range based on the remaining projects that are in the top quartile of the Line Prioritization Matrix following the historical trends of this program.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 AS PART OF THE MAJOR LINE REBUILD PROGRAM?

A. The Company has budgeted $61.1 million for the NSPM Major Line Rebuild program ($12.6 million in 2021; and $48.5 million in 2022). The Company has budgeted $80.9 million for the NSPW Major Line Rebuild program ($32.1 million in 2020; $33.7 million in 2021; and $15.0 million in 2022).

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE TOTAL NUMBER OF PROJECTS ENCOMPASSED BY THE MAJOR LINE REBUILD PROGRAM?

A. There are 19 discrete rebuild projects that are planned to be executed between 2020 and 2022. Eight are planned to be completed in 2020; seven in 2021; and four in 2022. These 19 projects make up 66 percent of the total budget for the Major Line Rebuild program during the term of the multi-year rate plan. The remaining budget for this program will be allocated to discrete projects once these projects are prioritized within and against the rest of the transmission portfolio.

Q. CAN YOU PROVIDE INFORMATION ABOUT A SPECIFIC REBUILD PROJECT THAT HAS BEEN IDENTIFIED FOR 2020 TO 2022?

A. Yes. The West St. Cloud – Black Oak Project involves rebuilding the Company's Line 0795, which is a 63-year old 69 kV transmission line that originates at Great River Energy's West St. Cloud Substation in St. Joseph, Minnesota and runs westerly approximately 25 miles to the Millwood Tap Switch in Freeport, Minnesota. This line is important because it serves the Company's as well as other utilities' distribution loads in the area.

This project was initially identified as part of the Company's systematic Major Line Rebuild program described above. Through the Company's Line Prioritization Matrix, the Company identified Line 0795 as being a poor performer due to its age and condition. The 1953 vintage line consists of direct embedded cedar wood poles. Many of the poles are past their useful life and over the years, many have been replaced through the Storm and Emergency program due to their poor condition. Continuing to replace singular structures is no longer an option due to the number of structures requiring replacement as well as the poor condition of the existing cross-arms and conductor. The cross-arms show evidence of physical decay and the conductor has failed in several locations. This project will be placed in service in 2022 and has a total plant addition of $18.5 million.

Q. PLEASE DESCRIBE THE NSPM/NSPW MAJOR LINE REFURBISHMENT PROGRAM.

A. The Major Line Refurbishment program for NSPM and NSPW encompasses a group of individual, targeted projects that aims to replace specific transmission line components, such as defective cross-arms, poles, and other line appurtenance components. This program differs from the Major Line Rebuild program in that the Rebuild program involves the complete removal and replacement of existing assets; whereas the Refurbishment program addresses specific defects on an entire line segment (breaker to breaker), replacing all like property units on the line segment.

The Company identifies these defective components as at or near failure by means of routine foot patrols, aerial patrols, or Field Engineer's Field Assessment (which occurs only as required by damage reports-estimated two percent of all lines annually). By refurbishing specific components of a line segment, and rather than rebuilding an entire line, the Company's intent is to increase circuit reliability and performance and extend the residual circuit life by more than 20 years, at a lower cost than a full line replacement.

Similar to our Rebuild program, the Company utilizes its assessment of the transmission system to help identify specific projects, which are then developed and prioritized in accordance with the Company's Line Prioritization Matrix. As with the Rebuild program, each transmission line is scored and ranked against each other based on the drivers noted above.

As with the Rebuild program assessment process, the Company may identify defective line circuits requiring refurbishment as early as five years before repairs are necessary. However, we typically budget lines for this program only two to three years in advance because upgrades in the system area, storms and emergencies, and changing system needs may alter the overall asset health score for identified lines beyond the two- to three-year window. The Company identifies, budgets for, and develops specific projects during our annual budget process and on the basis of the total asset health score of the line as determined by the Line Prioritization Matrix. These individual projects are then prioritized against the rest of the planned transmission capital portfolio. Lastly, the Company budgets for projects in the three- to five-year range based on the remaining projects that are in the top quartile of the Line Prioritization Matrix following the historical trends of this program.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 AS PART OF THE MAJOR LINE REFURBISHMENT PROGRAM?

A. The Company has budgeted $27.9 million for the NSPM Major Line Rebuild program ($7.8 million in 2020; $5.1 million in 2021; and $15.0 million in 2022). The Company has budgeted $20.0 million for the NSPW Major Line Refurbishment program ($3.3 million in 2020; $10.6 million in 2021; and $6.1 million in 2022).

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE TOTAL NUMBER OF PROJECTS INCLUDED IN THE MAJOR LINE REFURBISHMENT PROGRAM?

A. There are 20 discrete projects planned to be executed between 2020 and 2022. Nine are planned to be completed in 2020; three in 2021; and eight in 2022. These 20 projects make up 61 percent of the total of the budget of the Major Line Refurbishment program during the term of the multi-year rate plan. The remaining budget for this program will be allocated to discrete projects once these projects are prioritized within and against the rest of the transmission portfolio.

Q. CAN YOU PROVIDE INFORMATION ABOUT A SPECIFIC REFURBISHMENT PROJECT THAT HAS BEEN IDENTIFIED FOR 2020 TO 2022?

A. Yes, included in this program is a refurbishment of the Company's 69 kV transmission line located between Dodge Center and Zumbrota in southeastern Minnesota. This refurbishment project encompasses the entire length of the line (approximately 29 miles) but for a small section between structures 33 and 73 (approximately two miles) that was rebuilt to double circuit with the CapX2020 Hampton –La Crosse 345 kV Project.

The scope of the project includes the removal of all existing wood cross-arms with two vertical cap and pin insulators, which are located on the ends of the wood cross arms and have a history of failing. The wood cross-arms themselves have decayed over time and are beyond their expected useful life. These assets will be replaced with new horizontal post insulators. In addition, the scope includes the complete removal and replacement of 21 poles that have been identified as defective though our comprehensive inspection program. In total, approximately 448 structures will be modified and 21 wood poles will be replaced. The project is broken into three segments: 1) between the Company's Dodge Center Substation and Kasson Substation; 2) between Kasson Substation and Pine Island Substation; and 3) between Pine Island Substation and Zumbrota Substation.

Q. PLEASE PROVIDE AN OVERVIEW OF THE END-OF-LIFE REPLACEMENT (ELR) PROGRAMS.

A. The Company's ELR programs are a set of programs that are focused on replacing key components of our transmission facilities that have reached the end of their life. This includes a relay program, a substation transformer program, a substation breaker program, and line structure program.

Q. HOW DOES THE COMPANY IDENTIFY THOSE FACILITIES THAT HAVE REACHED THE END OF THEIR LIFE AND REQUIRE REPLACEMENT?

A. The Company's system sustainability group identifies facilities in need of replacement or refurbishment based on multiple factors. For transmission lines, these factors include:

- Age;
- Technology;
- Specific and Documented issues with the Asset Type;
- Synergy with other planned capital projects;
- Modernization initiative;
- Outage availability;
- Environmental issues;
- Condition of the asset known issues with a specific asset; and
- Part availability.

These factors receive different weights to determine which lines are in the greatest need of replacement. The system sustainability group prioritizes substation assets based on system criticality and asset condition. The priority list is then used to determine the urgency of each replacement and identifies specific projects.

Q. PLEASE DESCRIBE THE NSPM/NSPW ELR – RELAY PROGRAM.

A. The ELR – Relay program encompasses projects that target for replacement relays that exhibit poor performance and lack available replacement parts. As transmission infrastructure continues to age or nears or is at its end of life, these components must be changed before failures occur. As the structural integrity of aging assets diminishes, outages will increase in frequency and duration.

While we may identify a number of relays that require replacement as early as five years in advance of the asset's end of life, we typically budget for this program only two to three years in advance. During our annual budget process, the poorest performing relay projects are added to the budget. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year range are then planned for transmission's remaining relay infrastructure based on age and asset health. The pace of this replacement program may vary because many aging relays may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this project can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 FOR THE ELR – RELAY PROGRAM?

A. The Company has budgeted a total of $19.7 million for the ELR – Relay program: $7.3 million for the NSPM ELR – Relay program ($2.3 million in 2020; $3.3 million in 2021; and $1.7 million in 2022) and $12.4 million for

NSPW ELR – Relay program ($2.7 million in 2020; $7.7 million in 2021; and $2.0 million in 2022).

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE TOTAL NUMBER OF PROJECTS INCLUDED IN THE ELR – RELAY PROGRAM DURING THE TERM OF THE MULTI-YEAR RATE PLAN?

A. The Company has identified 22 discrete projects that comprise nearly 80 percent of the amount budgeted for 2020 to 2022. The remaining budget for this program will be allocated to discrete projects once these projects are prioritized within and against the rest of the transmission portfolio.

Q. PLEASE DESCRIBE THE NSPM/NSPW LINE ELR PROGRAM.

A. The Line ELR program for NSPM and NSPW encompasses projects that target the replacement of defective cross arms, poles, and other line appurtenance components on the NSP System that have been reported as defective by routine foot and aerial patrols and are nearing their end of life. Overall, Line ELR allows for the extension of the life of NSP transmission line assets when full line replacement is not necessary. Line ELR is utilized primarily when the individual defect has occurred but the overall line segment is otherwise in sound condition with many years of additional life remaining.

Q. HOW DOES THE LINE ELR PROGRAM DIFFER FROM THE MAJOR LINE REFURBISHMENT PROGRAM DISCUSSED ABOVE?

A. The Major Line Refurbishment program replaces specifically identified defective transmission line property units (cross-arms or poles or other line appurtenances) when the majority of similar property units of the same vintage and design have been identified as defective on a line circuit. Any property units found to be in good operational condition are left in place.

In contrast, the Line ELR program replaces only individual transmission line property units that are defective, but not similar property units of the same vintage and design that are generally in good operating condition.

When defects are identified through patrols, typically one to three years in advance, they are classified as either Major Line Refurbishment or Line ELR, and they are budgeted and executed. These two programs are managed separately because the severity of the identified defects on a circuit, along with the frequency of the defects, determines which program will be utilized.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 FOR THE LINE ELR PROGRAM?

A. The Company has budgeted \$9.6 million for the NSPM Line ELR program (\$2.3 million in 2020; \$3.6 million in 2021; and \$3.7 million in 2022). The Company has budgeted \$11.3 million for the NSPW Line ELR program (\$9.0 million in 2021; and \$2.3 million in 2022).

Q. PLEASE DESCRIBE THE NSPM NUCLEAR SUBSTATION ELR PROGRAM.

A. This program has been separated from the Company's other ELR programs so that it can more easily be completed in coordination with our Nuclear business unit's compliance needs. The Nuclear Substation ELR program addresses the programmatic replacement of substation equipment at the substations that serve the Monticello and Prairie Island nuclear generating plants. The timing of these replacements is designed to align transmission's substation replacement activities with power plant refueling and maintenance activities at these two nuclear facilities. The equipment identified for replacement consists largely of circuit breakers, switches, relays, and power transformers. While the program can be flexible from year to year, replacement of these facilities is necessary to maintain the ability to transport the energy generated by these plants to customers.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 FOR THE NSPM ELR NUCLEAR PROGRAM?

A. The Company has budgeted $12.3 million for the NSPM ELR Nuclear program ($1.0 million in 2020; $4.5 million in 2021; and $6.8 million in 2022).

Q. PLEASE DESCRIBE THE NSPM/NSPW SUBSTATION BREAKER ELR PROGRAM.

A. The NSPM/NSPW Substation Breaker ELR program targets circuit breakers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. As transmission infrastructure ages or nears or is at its expected end of life, components must be changed before failures occur. As the structural integrity of these aging assets diminishes, outages will increase in frequency and duration.

As with the ELR – Relay program, while we may identify a number of circuit breakers through the Substation Breaker ELR program that require replacement as early as five years in advance, typically we budget lines for this program only two to three years in advance. During our annual budget process, the poorest performing circuit breaker projects are pulled into the budget. These projects are then prioritized against the rest of the planned transmission portfolio. Budgets for projects in the three- to five-year range are then planned for transmission's remaining circuit breaker infrastructure based on the age and asset health. The pace of this replacement program may vary because many aging breakers may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this project can be accelerated or decelerated dependent on other transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 FOR THE NSPM/NSPW SUBSTATION BREAKER ELR PROGRAM?

A. The Company has budgeted $4.6 million for the NSPM Substation Breaker ELR program for seven discrete projects ($1.2 million in 2020; $1.3 million in 2021; and $2.1 million in 2022). The Company has budgeted $11.2 million for the NSPW Substation Breaker ELR program for five discrete projects as well as several yet to be determined projects ($1.6 million in 2020; $7.8 million in 2021; and $1.8 million in 2022).

Q. PLEASE DESCRIBE THE NSPM/NSPW STORMS AND EMERGENCY (S&E) LINE PROGRAM.

A. The S&E Line program for NSPM and NSPW is a funding program for equipment that fails while in-service due to storm events or is identified through condition assessment as having a high probability of failure and cannot wait for the next normal budget cycle for replacement. This work is typically performed in response to weather events, unforeseen events, and other unscheduled maintenance work that, if not completed, puts the system at imminent risk of failure. The work typically includes the replacement of arms, poles, conductor, insulators, and other line appurtenances.

The Company sets its budgeting for this program based on a historical annual average because the nature of the work to be performed is not known until the time of an incident. The forecast is then adjusted throughout the year based on actual incidents, while factoring in the probability of storm or emergency events for the remainder of the calendar year.

Based on historical average budgeting for this program, transmission's plant additions for any given year range between $3.5 million and $5.5 million per year. One of the reasons for this budget range is because the Company occasionally experiences late season storms or emergencies for which the physical work and capital expenditure must carry over from one budget year to the next, causing the plant addition to be carried over from one year to the next.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 FOR THE NSPM/NSPW S&E LINE PROGRAM?

A. The Company has budgeted $13.8 million for the NSPM S&E Line program ($3.7 million in 2020; $5.2 million in 2021; and $5.0 million in 2022). The Company has budgeted $14.5 million for the NSPW S&E Line program ($5.4 million in 2020; $5.6 million in 2021; and $3.6 million in 2022). These costs are typically budgeted based on a historical costs as well as an assessment of the overall state of our transmission facilities. For Minnesota, we are budgeting increasing amounts for the S&E Line Program in 2021 and 2022 due to the slight decrease in spending on non-emergency asset renewal. In contrast, due to slight increases in spending on non-emergency asset renewals in Wisconsin, we are budgeting a reduction in S&E Line Program investment for 2022.

Q. DESCRIBE THE TRANSMISSION UAV PROJECT.

A. Xcel Energy is using new technology to enhance safety and efficiency of its operations. The Company is leading the utility industry with the use of Unmanned Aircraft Systems (or "drones") to fly Beyond the Visual Line Of Sight that will collect electronic (inspection) data on transmission lines. This data collected will integrate into the Company's existing GIST models to create a complete 3D model of the transmission lines. This complete model with all of the data collected then aids the transmission business area in line and substation ratings, operations, and maintenance decisions. UAV technology is a new way for Xcel Energy's data collection that is safer than traditional helicopters and allows for better data quality since the UAVs can fly lower and slower above our transmission lines. UAV also offers a potential advantage to inspect hard to reach sites, reduce costs, and improve response time. The technology also allows advantages in accessing environmentally sensitive areas by minimizing ground impact.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2020 TO 2022 FOR THE TRANSMISSION UAV PROJECT?

A. The Company has budgeted 12.3 million for the Transmission UAV Project ($8.4 million for NSPM and $3.9 million for NSPW), all to be incurred in 2021.

4. *Communication Infrastructure Projects*

Q. WHY ARE INVESTMENTS IN COMMUNICATION INFRASTRUCTURE NECESSARY?

A. In the past, the Company has relied on third-party telecommunication providers for the infrastructure necessary for our SCADA and teleprotection circuits (i.e., communication circuits between our substations and between our substations and our control center). However, many of the telecommunication companies are phasing out their dedicated frame relay and analog wide area network (WAN) technology and replacing it with Ethernet over fiber optics or other broadband services. These new services, while capable of carrying large volumes of data, are not able to carry the small amount of data that we transmit at the speeds acceptable for the teleprotection of our transmission system. As a result, we need to invest in Company-owned and controlled communication infrastructure using fiber optic cable that will serve our operational and system protection needs without the reliance on and vulnerability exposure from a publicly available third-party network.

Similarly, cyberattacks pose a threat to the reliability of our transmission system as hackers could cause system outages by disabling telecommunications or key pieces of equipment. Every day there are coordinated attempts to infiltrate communication systems and disrupt the grid. Federal regulatory agencies have responded to these growing threats by adopting cybersecurity standards for transmission facilities. The Company-owned telecommunications network we are investing in enables the Company to reduce our exposure to cybersecurity threats from the publicly available service provided by third-party telecommunication providers.

Q. WHAT ARE THE KEY COMMUNICATION INFRASTRUCTURE PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. The Communication Infrastructure projects that will be placed in-service between 2020 and 2022 will arise out the Communication Network program.

Q. DESCRIBE THE COMMUNICATIONS NETWORK PROGRAM.

A. The Communication Network program aims to privatize Xcel Energy's communication network infrastructure across the NSPM and NSPW service territories, wherever possible, at all transmission and distribution substations for SCADA, teleprotection, and remote engineering access. Specifically, the program addresses aging analog circuit technology, particularly technology that is anticipated to become obsolete within five years. The Company will then build secure communication architecture for physically isolated operational technology (OT) and information technology (IT) networks to support islanding of the energy management system (EMS). The program will enable the Company to reduce dependency on third-party circuit providers, which will improve the Company's troubleshooting response time and reduce circuit down time. The Company will also be able to save on recurring O&M costs.

The Company has budgeted $20.1 million for the NSPM Communication Network program ($0.4 million in 2020; $4.9 million in 2021; and $14.8 million in 2022). The Company has budgeted $9.8 million for the NSPW Communication Network program ($4.9 million in 2021; and $4.9 million in 2022).

5. Interconnection Projects

Q. WHAT IS DRIVING TRANSMISSION'S INTERCONNECTION INVESTMENTS?

A. Under our tariff, we are required to make the necessary transmission upgrades to accommodate interconnection requests. There are three general types of Interconnection projects that drive our interconnection investments: transmission interconnections, load interconnections, and generation interconnections. Transmission interconnections are where one utility is requesting to interconnect a transmission line to our transmission line. Load interconnections are where a new substation serving electric load is needed and is requesting to interconnect to our transmission system, or an existing load serving substation is being modified. Generation interconnections are where a new generator is requesting to interconnect to our transmission system.

Q. WHAT ARE THE KEY INTERCONNECTION PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. The Interconnection projects that will be placed in-service between 2020 and 2022 will arise out the IA Tariff Fund program.

Q. DESCRIBE THE IA TARIFF FUND PROGRAM.

A. This program fund is for interconnection related transmission capital investments as a result of developments or requests by organizations outside the Company or by internal NSP departments, other than the transmission planning department. The program is for load interconnection requests that have not yet reached the specificity to be defined as specific capital projects but nonetheless are expected based on announced plans or interconnection requests in the MISO queue that require capital funding during the five-year budget period.

The Company has budgeted \$8.6 million for the NSPM IA Tariff Fund (\$1.5 million in 2020; \$3.0 million in 2021; and \$4.1 million in 2022). The

Company has budgeted $9.2 million for the NSPW IA Tariff Fund ($0.99 million in 2020; $3.1 million in 2021; and $5.1 million in 2022).

6. *Physical Security and Resiliency Projects*

Q. WHAT ARE THE MAJOR ISSUES FACING TRANSMISSION WITH REGARD TO PHYSICAL SECURITY AND RESILIENCY?

A. Transmission is focused on maintaining the physical security of our assets. High voltage transformers comprise less than three percent of transformers in U.S. electric power substations, but they carry 60 to 70 percent of the nation's electricity. Because they serve as vital nodes and carry bulk volumes of electricity, these transformers are critical elements of the nation's electric power grid. They are also the most vulnerable to intentional damage from malicious acts. In April 2013, for example, a substation in California was subject to a coordinated military-type sniper attack that disabled 17 high voltage transformers, rendering this substation useless.

Federal regulatory agencies have since responded to these growing threats by adopting physical security standards for transmission facilities. On March 7, 2014, FERC issued an Order on Reliability Standards for Physical Security Measures, which ultimately led to NERC standard CIP-014 addressing risks due to physical security threats and vulnerabilities. To address these threats and meet these new NERC standards, we are making necessary investments to make our grid more resilient so that we can respond quickly to physical security threats.

Q. WHAT ARE THE KEY PHYSICAL SECURITY AND RESILIENCY PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. The Physical Security and Resiliency projects that will be placed in-service between 2020 and 2022 will arise out of two programs: (1) NSPM Physical Security; and (2) NERC Circuit Protection Order.

Q. PLEASE DESCRIBE THE NSPM/NSPW PHYSICAL SECURITY PROGRAM.

A. The NSPM/NSPW Physical Security program was developed to ensure the Company's compliance with the NERC-CIP-014 Physical Security Standard. Additionally, the program aims to improve substation site security where the Company's Protection Services department has identified ongoing theft issues. The purpose of this program is to improve the physical security of the Company's substations. The Company is developing site-specific security plans for specific substations and is obtaining third-party verification of the effectiveness of these plans. These site-specific security plans may include the following security measures: cameras, fencing/barrier improvements, ballistic shielding of identified key substation equipment, site access controls, ground sensory monitoring, and radar technology. This program is planned for 15 discrete substation sites in 2020, 10 discrete substation sites in 2021, and eight discrete substation sites in 2022.

The Company has budgeted $28.6 million for the Physical Security program ($8.8 million in 2020; $11.5 million in 2021; and $8.3 million in 2022).

Q. PLEASE DESCRIBE THE NERC CIRCUIT PROTECTION ORDER PROGRAM.

A. The NERC Circuit Protection program was initiated to comply with FERC Order 754, which required that the Company have redundant relaying and circuit breaker tripping to prevent large-scale system impacts in the event of a fault during the loss of primary relaying. The scope requires that multiple substations upgrade relays, separate primary and secondary relaying, and add redundant DC circuits over multiple years of construction.

On September 15, 2011, FERC issued Order No. 754 Interpretation of Transmission Planning Reliability Standard in which FERC stated, "there is an issue concerning the study of the non-operation of non-redundant primary protection systems e.g., the study of a single point of failure on protection systems." FERC also directed NERC to initiate a process "to explore this reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter." The resulting NERC assessment confirmed the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. In response, Order 754 modified NERC Transmission Planning Standards to address single points of failure within a system to eliminate the reliability risk.

Under FERC Order 754, the Company must identify single point failures at critical substations with voltages of 200 kV or above and report the results to NERC. The Company has studied the relevant substations and identified certain required modifications to eliminate these single point failures. This project includes separating primary and secondary relaying and adding redundant direct current circuits at several Company-owned substation facilities. This separation allows a back-up battery to continue to provide protection services in the case the primary battery fails.

The Company has budgeted \$14.7 million for the NERC Circuit Protection Order program for NSPM (\$3.0 million in 2020; \$7.8 million in 2021; and \$3.9 million in 2022).

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE OVERALL LEVEL OF TRANSMISSION CAPITAL COSTS THE COMPANY IS SEEKING TO RECOVER IN THIS RATE CASE?

A. The overall level of transmission capital costs is reasonable, as shown by the above discussion, and is necessary to support an appropriate level of service to our customers and to meet the applicable NERC requirements. Finally, the costs included in our 2020 through 2022 capital budgets are representative of the types of work we must and will do year over year.

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN THE TRANSMISSION O&M BUDGET?

A. The transmission O&M budget includes costs associated with the operation and maintenance of our transmission system. This includes internal and contract labor, employee expenses, fees, and materials.

Q. WHAT ARE THE TRANSMISSION O&M BUDGETS FOR 2020 TO 2023?

A. As shown in Table 8, we have budgeted \$39.2 million for transmission O&M in 2020, \$37.9 million in 2021, and \$38.1 million in 2022.

Table 8 also provides our actual O&M costs for 2016-2018 and the 2019 forecast for O&M spend (half year actuals and half year forecast). I provide the dollar figures for both NSPM and NSPM– State of Minnesota Jurisdiction. Exhibit___(IRB), Schedule 3 also provides the transmission O&M costs by cost element for 2016-2018.

Table 8

Transmission O&M Budget by Category NSPM-Electric (Dollars in Millions)								
Cost Category	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2016 – 2018 Average**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
Internal Labor	$23.50	$21.40	$22.00	$22.30	$22.10	$22.50	$23.00	$23.60
Contract Labor and Consulting	$6.80	$4.70	$4.50	$5.30	$4.20	$3.70	$3.70	$3.80
Employee Expenses	$2.40	$2.70	$2.90	$2.70	$2.60	$2.80	$2.80	$2.90
Fees*	$3.70	$3.50	$3.50	$3.60	$3.60	$3.70	$4.10	$4.30
Materials	$3.00	$3.60	$3.30	$3.30	$2.80	$3.20	$2.60	$2.70
Other	$3.80	$5.10	$4.10	$4.30	$1.00	$3.30	$1.70	$0.80
Total	**$43.20**	**$41.00**	**$40.30**	**$41.50**	**$36.30**	**$39.20**	**$37.90**	**$38.10**
* The "Fees" cost category includes Dues, Fees, and Licenses, which includes professional & utility association dues, as well as land and railroad permits and license fees, as well as NERC and FERC assessments.								

Table 9

Transmission O&M Budget by Category Minnesota Electric Jurisdiction (Net of Interchange Billings to NSPW) (Dollars in Millions)								
Cost Category	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2016 – 2018 Average**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
Internal Labor	17.3	15.8	16.2	16.5	16.2	16.4	16.8	17.2
Contract Labor and Consulting	5.0	3.5	3.3	3.9	3.1	2.7	2.7	2.7
Employee Expenses	1.8	2.0	2.2	2.0	1.9	2.0	2.1	2.1
Fees*	2.7	2.6	2.6	2.6	2.6	2.7	3.0	3.1
Materials	2.2	2.7	2.5	2.5	2.0	2.3	1.9	1.9
Other	2.9	3.7	3.1	3.2	0.7	2.5	1.2	0.8
Total	31.9	30.3	29.9	30.7	26.5	28.6	27.7	27.8

* The "Fees" cost category includes Dues, Fees, and Licenses, which includes professional & utility association dues, as well as land and railroad permits and license fees, as well as NERC and FERC assessments.

Q. WHAT ARE THE TRANSMISSION O&M BUDGET CATEGORIES?

A. As can be seen from Table 9 above, the transmission business unit O&M budget consists of six main cost categories: (1) internal labor; (2) contract labor and consulting; (3) employee expenses; (4) fees; (5) materials; and (6) other. I describe these categories in detail later in my testimony.

B. O&M Budgeting Process

Q. HOW DOES THE COMPANY SET THE O&M BUDGET FOR THE TRANSMISSION BUSINESS UNIT?

A. As with our capital budget, the O&M budget for the transmission business unit is built using a bottom-up approach. Each budget manager reviews their needs factoring in work plans as well as any anticipated efficiency gains for the coming years and develops budgets in accordance with those needs and anticipated efficiency improvements. As part of this bottom-up process, the field operations and construction units review those facilities that need repairs to extend their asset life, addressing issues like broken insulators, loose hardware, woodpecker damage, broken or damaged guy wires, etc. In this way, Asset Renewal projects are a driver of the O&M budgeting process. The individual manager budgets are then consolidated for a total transmission O&M budget and analyzed for reasonableness and accuracy as compared to recent actual trends. This process includes normalizing the actual spend for those expenses that are not expected to continue into the budget year due to changes in business conditions or one-time events. The total transmission business unit budget is compared to the overall Company targets, which are discussed further in Mr. Robinson's Direct Testimony. If the budget is greater than the overall Company targets provided to transmission, the needs are prioritized with the most critical needs funded first and the least critical needs funded last.

Q. DOES THE TRANSMISSION BUSINESS UNIT EVER NEED TO CHANGE THE ALLOCATION OF O&M FUNDS DURING THE FINANCIAL YEAR?

A. Yes, the transmission business unit has had to change the allocation of O&M funds during the financial year. Unexpected operational or regulatory events, such as additional NERC compliance requirements, during the year can cause additional unplanned transmission O&M costs. When this occurs, we make every effort to re-evaluate activities within the transmission business unit to absorb the unexpected costs. In addition, the transmission business unit will periodically receive a request from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. This again results in the re-evaluation of activities and the reduction of non-critical activities. While the transmission business unit makes every effort to respond to changes in business conditions within the given targets, there are times where circumstances dictate that we will need to spend more than the targets provided by the Company in order to maintain safe, reliable service to our customers and to properly address certain items that come about during a given budget year. For example, there are certain CIP standards that require compliance by a particular deadline and our work on meeting these standards cannot be delayed.

Q. HOW DOES THE COMPANY DETERMINE CHANGES IN THE O&M BUDGET?

A. The transmission business unit re-evaluates the business needs annually in development of the O&M budget. As those needs change, the budget is prioritized to fund the most critical needs first. If the funding required for critical needs is greater than the Company target provided to the transmission business area, the critical needs that are not funded within the targets provided are brought to the Company to be prioritized along with the needs of the other business units. For example, if a new NERC compliance requirement is implemented that will cause a substantial change in O&M expenditures and was not contemplated in the targets provided by the Company, additional funding may be requested by the transmission business area to cover that need.

During any given year, we are routinely monitoring our O&M actual expenditures versus their associated budgets and identifying any variances of significance as they materialize. As budget pressures are identified in certain areas or programs, options are reviewed to mitigate those pressures. One mitigation option would be the reallocation of funds from other areas, where budgeted work of a lower priority or more discretionary nature in the short-term may be reallocated to cover the programs experiencing the budget pressures. If the amount needing funding cannot be funded prudently within the overall transmission business unit O&M budget, the issue is brought forward to the Company as a request to increase the overall O&M target for the transmission business unit.

Q. PLEASE EXPLAIN HOW THE TRANSMISSION BUSINESS UNIT MONITORS O&M EXPENDITURES.

A. The transmission business unit is supported by a dedicated finance team. The finance team prepares monthly reporting for the transmission business area that includes reviews of the current month actual versus budget, year-to-date actual versus budget, and year-end forecast versus target. This reporting is provided to the individual budget managers with summaries at the director and overall transmission business unit level. The summarized reporting is reviewed on a monthly basis with the transmission leadership team, where concerns or issues are also discussed.

Q. HOW DOES THE TRANSMISSION BUSINESS UNIT O&M BUDGET PROCESS AND GOVERNANCE COMPARE TO INDUSTRY PRACTICE?

A. The process the transmission business unit uses in the development of the O&M budget is consistent with the practices used in the other business units across the Company. As discussed above, the budget development is accomplished through a bottom-up approach where each budget manager develops their budget based on identified work plans and efficiency gains for the budget year and prioritized based on the most critical activities to ensure the Company targets are met. During the year, governance is accomplished through the monthly reporting and monitoring of performance as well as formal tracking of changes to the year-end targets by director within an operating company, as discussed above. Any changes to the year-end targets within the transmission business unit are approved by the Senior Vice President of Transmission. Any changes to the overall transmission business unit targets and brought forward to the Company for consideration. Further discussion of the overall Company budget process and governance is discussed in the Direct Testimony of Mr. Robinson.

Q. HOW ARE THE TRANSMISSION BUSINESS UNIT LONG-TERM O&M COSTS TRENDING?

A. The transmission business unit has made efforts to decrease our O&M budget from recent historical trends. Overall, the transmission O&M budget for 2020 to 2022 trends lower than 2016 to 2018 actuals. This decrease is primarily driven by productivity improvement initiatives that have been implemented by transmission. These efforts have driven improved scheduling and field productivity, resulting in more efficient and effective ways for transmission crews to schedule and complete their work, thus reducing O&M expenditures. Additionally, an industry benchmarking analysis resulted in changes to the Company's repair versus replacement policies to promote replacement over repair for assets that required repeated costly repairs. These initiatives, and the resulting reductions in O&M expense, have been executed to offset ongoing inflationary pressures, as well as pressures resulting from the Company's asset growth. For example, scheduling efficiencies have driven the organization from a 41 percent to a 90 percent average scheduling efficiency. This allows work to be planned and executed in a more efficient manner reducing the overall O&M cost of the work. Some examples of the efforts that led to the increased efficiency include locking in the schedules a week prior, more detailed scheduling, formalized job readiness checklists, minimization of schedule changes, and daily huddles with leadership and crews to discuss daily work plans.

Q. HOW DOES THE TRANSMISSION O&M BUDGET FOR 2020 TO 2022 COMPARE TO 2018 ACTUALS?

A. Transmission's O&M budget for each of these three years is lower than 2018 actuals by an average of five percent. This is driven primarily by productivity improvement initiatives, which have been implemented by the business.

Q. WHAT ARE THE OTHER MAJOR COST DRIVERS OF THE TRANSMISSION O&M BUDGET FOR 2020 TO 2022 THAT HAVE RESULTED IN AN OVERALL DECREASE IN O&M COSTS FROM 2018?

A. The overall decrease from 2018 actuals to the 2020 to 2022 O&M budget is driven by the productivity improvements mentioned above. This decrease was only partially offset by increases in the following categories: 1) base pay increases; 2) non-labor inflation; 3) fees; 4) asset growth and compliance. Table 10 summarizes the impacts of these items on the O&M budget.

Table 10

Transmission 2020-2022 Budget vs. 2018 Actual O&M Expenditures NSPM-Electric (Dollars in Millions)		
Cost Drivers	**Amount**	**Total**
2018 Actual		**$40.3**
Base Pay (3% annual increase)	$1.3	
Non-labor Inflation (1% annual increase)	$0.3	
Fees: NERC, Professional and Association Dues, and License Fees	$0.2	
Productivity Improvement Initiatives	$-3.0	
Miscellaneous Other	$0.1	
2020 Budget		**$39.2**
Base Pay (3% annual increase)	$0.7	
Non-labor Inflation (1% annual increase)	$0.1	
Fees: NERC, Professional and Association Dues, and License Fees	$0.4	
Productivity Improvement Initiatives	$-2.9	
Asset Growth and Compliance	$0.3	
Miscellaneous Other	$0.1	
2021 Budget		**$37.9**
Base Pay (3% annual increase)	$0.7	
Non-labor Inflation (1% annual increase)	$0.1	
Fees: NERC, Professional and Association Dues, and License Fees	$0.2	
Productivity Improvement Initiatives	$-1.2	
Asset Growth and Compliance	$0.3	
Miscellaneous Other	$0.1	
2022 Budget		**$38.1**

Q. HOW DO THE 2020 TO 2022 O&M BUDGETS COMPARE WITH THE 2019 FORECAST?

A. Transmission's O&M budget for each of these three years is slightly higher than the 2019 forecast due to annual base pay increases as well as increases in fees from 2020 through 2022. In addition, as compared to our historic O&M spend, the 2019 forecast is an outlier in that it is $5.2 million below the 2016-2018 historic average. This is the result of the acceleration of certain O&M expenses into late 2018 that then reduced 2019 O&M

expenses. Transmission's 2019 O&M expenses are also lower due to a backlog of maintenance projects due to prioritization of other types of work during 2019. This backlog of maintenance work will be addressed in 2020 thus increasing the 2020 O&M budget as compared to 2019.

Q. HOW DOES THE 2021 O&M BUDGET COMPARE TO THE 2020 BUDGET?

A. The 2021 O&M budget is three percent lower than the 2020 budget. This is due to the full realization of productivity improvement initiatives implemented by transmission, resulting in reduced O&M expenditures. These reductions are partially offset by the impacts of base pay increases, non-labor inflation, and growth in fees.

Q. HOW DOES THE 2022 O&M BUDGET COMPARE TO THE 2021 BUDGET?

A. The 2022 O&M budget is one percent higher than the 2021 budget. This is primarily driven by base pay increases, non-labor inflation, fee increases, and asset growth but is partially offset by additional realization of productivity improvement initiatives implemented by the transmission organization.

C. O&M Budget Detail

1. Internal Labor

Q. WHAT INTERNAL LABOR COSTS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT O&M BUDGET?

A. This category represents the O&M portion of salaries, straight time labor, overtime, and premium time for internal employees. An attrition factor of four percent is also applied, which reduces labor costs to account for retirements, hiring delays, and other employee transfers. These amounts include costs for both NSPM employees and the appropriate allocation of

Xcel Energy Services employees. For capital construction-focused positions, the vast majority of the labor costs are allocated to capital; however, some labor costs are charged to O&M activities like employee meetings, training, and administrative functions.

Q. WHAT CHANGES IN INTERNAL LABOR COSTS DO YOU ANTICIPATE FOR 2020 TO 2022?

A. We are expecting an average annual increase of three percent in internal labor costs for 2020 to 2022, as compared to the 2016 to 2018 average for internal labor costs.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN INTERNAL LABOR COSTS FROM 2020 TO 2022?

A. The 2020-2022 budgets include increases in labor expenses over the average 2016-2018 actuals due to the annual base pay increase of three percent. The transmission business unit budgets for base pay increases at the level determined by human resources for non-bargaining employees, and as set forth in collective bargaining agreements for bargaining employees. For non-bargaining employees, the 2020 to 2022 base pay increases reflect a percentage increase which is consistent with market median values. With that said, the annual base pay increases for our bargaining and non-bargaining employees and the historical trends for base pay increases are discussed more fully in the Direct Testimony of Company witness Ms. Ruth K. Lowenthal.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN INTERNAL LABOR COSTS.

A. The transmission business unit closely monitors our overall headcount numbers, ensuring that any increases in headcount above the budgeted levels are prudent and fully reviewed. In addition, we closely monitor the amount of time spent on capital activities on a monthly basis as part of the overall monthly reporting to manage the amount of internal labor being charged to O&M.

2. *Contract Labor and Consulting*

Q. WHAT COSTS ARE INCLUDED IN THE O&M BUDGET FOR CONTRACT LABOR AND CONSULTING?

A. This category represents our use of contract labor and consultants, which allows the Company to increase and decrease its staffing levels as workloads require rather than bringing on more full-time staff, and to retain the services of experts as needed for specific tasks or project efforts. We believe utilizing contractors and consultants in this way is an efficient and cost-effective way to complete required work while ensuring the cost for the resources is only incurred during time it is needed.

Q. WHAT CHANGES IN CONTRACT LABOR AND CONSULTING COSTS DO YOU ANTICIPATE FOR 2020 TO 2022?

A. We are expecting an average decrease of 30 percent in contract labor and consulting costs for 2020 to 2022, as compared to the average of the 2016-2018 actual costs.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THIS DECREASE IN CONTRACT LABOR AND CONSULTING COSTS?

A. While utilizing contractors and consultants can be a cost-effective method of managing labor costs on projects with variable workloads, the transmission business unit continues to take steps to minimize the cost of contract labor and consulting costs. This includes increasing the reliance on workload planning to ensure the staffing levels, including both internal and external resources, are at the minimum levels required to achieve the optimal staffing levels. Furthermore, the transmission business unit utilizes strategic sourcing and the competitively bid Master Service Agreement program to obtain qualified and cost-effective contract labor. The Master Service Agreement program creates supply agreements with several preferred vendors to obtain bulk discounts and better service. The 2020-2022 budgets include decreased contract labor and consulting costs, as compared to the average 2016-2018 actuals. This is driven by productivity improvement initiatives, which have been implemented by the business. These efforts have resulted in improved scheduling and field productivity, resulting in more efficient and effective ways for transmission crews to spend their time, thus reducing the need for contractor support and the outsourcing of certain O&M activities.

3. Fees

Q. WHAT FEES ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists of fees we are required to pay to the NERC and MRO for the operation of the transmission system. As a regulated utility, the Company is required to pay fees for each of those organization's operating costs. It also includes professional and utility association dues, as well as land and railroad permits and license fees, and other similar fees necessary for the operation of our business.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN FEES FROM 2020 THROUGH 2022?

A. The increase in the fees cost category for 2020 through 2022 is primarily attributable to increases in regulatory fees. The Company forecasts its regulatory fees based on guidance from the regulatory bodies. Guidance from NERC and MRO suggested an eight to 10 percent increase in 2020 for both organizations. Consistent with this guidance, the Company has budgeted an average increase of nine percent for 2020 to 2022 as compared to the 2016-2018 actuals.

4. *Materials*

Q. WHAT MATERIALS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists primarily of consumables, hardware, and refurbished materials used in substation maintenance and repair operations. Additionally, tools, small equipment, and supporting supplies are included.

Q. WHAT CHANGES IN MATERIALS COSTS DO YOU ANTICIPATE FOR 2020 TO 2022 AS COMPARED TO 2018 ACTUALS?

A. We are expecting an average decrease of 15 percent in materials for 2020 to 2022, as compared to the average of the 2016-2018 actual materials. The 2020 budget for materials is 14 percent higher than the 2019 forecast for materials. This is driven by certain O&M expenditures, which were accelerated from 2019 into late 2018, resulting in a reduction in materials spend in 2019.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND DECREASES IN MATERIAL COSTS?

A. The 2020-2022 budget for material costs trends lower than the 2016-2018 actual material costs. These decreases are driven by policy reviews conducted by the Company, leading to enhanced repair versus replace decisions, thus reducing O&M expenditures for materials. In addition, the transmission business unit continues to take advantage of the Master Service Agreement program, utilizing negotiated supply agreements with several preferred vendors to obtain bulk discounts and better service. We are also continuing to look for opportunities to optimize the sourcing for materials through efficiencies gained within the supply chain organization.

5. Miscellaneous

Q. WHAT COSTS ARE INCLUDED IN THE MISCELLANEOUS CATEGORY?

A. The miscellaneous category is primarily fleet costs. This category consists of costs for the internal fleet assets as directed to O&M accounts on an hourly basis by transmission operations. This is an aggregate cost of all fleet equipment charged to transmission O&M, including cars, trucks, construction equipment and trailers. In addition to fleet costs, the miscellaneous budget for 2020-2022 includes anticipated reductions in O&M as a result of productivity enhancements expected to be implemented by the Company.

Q. WHAT CHANGES IN MISCELLANEOUS COSTS DO YOU ANTICIPATE FOR 2020 TO 2022 AS COMPARED TO 2018 ACTUALS?

A. We are expecting an average decrease of 56 percent in miscellaneous costs for 2020 to 2022, as compared to the 2016-2018 average. Efforts to reduce per unit expense for transportation costs have resulted in decreased total fleet expenditures. Additionally, improvements in vehicle utilization tracking have resulted in fleet time and dollars being more accurately assigned to capital versus O&M projects, resulting in reduced O&M spend. Lastly, certain anticipated O&M reductions resulting from efficiency efforts initiated by the Company are captured in the miscellaneous cost category for the 2020-2022 budget. As the total impact of these initiatives has not been fully realized, a portion of the expected cost reductions has been included in miscellaneous, as opposed to the individual cost categories.

V. THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES

A. Overview of the Transmission System in Minnesota and the Upper Midwest

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the Company's third-party transmission revenues and expenses and the impact that pending FERC proceedings have on those revenues and expenses.

Q. GENERALLY SPEAKING, WHAT ARE THIRD-PARTY TRANSMISSION EXPENSES?

A. While NSP System loads and transmission facilities are primarily located within the NSP pricing zone, the NSP Companies serve loads in five other MISO pricing zones, and a small load outside MISO. The NSP Companies also collect revenue for transmission facilities located in the Great River Energy (GRE) pricing zone, and several other utilities collect revenue for transmission facilities located in the NSP pricing zone.

As a result, the NSP System incurs third-party transmission expenses where the NSP Companies serve their native load customers in other zones, including Joint Pricing Zone (JPZ) arrangements developed to compensate other utilities for their facilities in the NSP pricing zone consistent with the MISO Transmission Owners Agreement. On the other hand, the NSP System also receives revenues for transmission and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets.

Q. WHAT IS THE RELATIONSHIP OF THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES TO THE COMPANY'S COST OF SERVICE?

A. Third-party transmission expenses and wholesale transmission revenues can either serve as a credit or debit to the transmission business unit's O&M costs.

Q. PLEASE DESCRIBE THE HISTORIC DEVELOPMENT OF THE 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. The Company serves the Twin Cities, several major cities including St. Cloud, Mankato, and Winona, and about 400 other communities in Minnesota, while other utilities serve areas between the Company's territories. This is because electric utilities in Minnesota and the upper Midwest (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 THE HISTORY OF COOPERATION 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 a general decrease in costs to customers throughout Minnesota.

Today, access to that multi-owner transmission grid is available under the MISO Tariff. Essentially, the Company receives revenue from other entities that use our transmission system and incurs an expense for using the transmission system of other entities.

B. Third-Party Transmission Expenses and Revenues

Q. PLEASE EXPLAIN HOW THE WHOLESALE REVENUES AND THIRD-PARTY EXPENSES ARE RECOVERED.

A. The MISO Tariff recovers the costs of transmission facilities through rates established and billed by "pricing zones," which 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. HOW DOES THE BILLING WORK?

A. The Company is party to "Joint Pricing Zone" (JPZ) agreements for both the NSP pricing zone and the Great River Energy (GRE) pricing zone. Under these agreements, 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. Since the NSP Companies are both transmission owners and load serving entities in both pricing zones, the NSP System (1) receives revenues for its facilities in the NSP and GRE pricing zone, and (2) incurs expenses for its loads in the NSP and GRE pricing zones.

Furthermore, as a MISO transmission owner, the NSP Companies collect third-party wholesale transmission service revenues for others' use of the NSP System under both the MISO Tariff and other wholesale transmission agreements. The NSP System also incurs transmission and/or ancillary expenses for its loads in other MISO pricing zones.

Q. PLEASE DESCRIBE THE TRANSMISSION THIRD-PARTY EXPENSES AND WHOLESALE REVENUES FOR 2020 TO 2022.

A. The NSP System (NSPM and NSPW combined) 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 NSP System loads, including NSPM retail native loads in Minnesota, and thus the costs should be included in rates. However those costs are offset by various transmission service revenues, thereby reducing total costs to NSPM customers in Minnesota. Table 11 summarizes the 2020-2022 budgets for MISO third-party transmission revenues and expenses and administrative charges for the total NSP System, compared to 2018 actual and 2019 forecast amounts.

Table 11

NSP System Third Party Transmission Expenses and Revenues ($000s)					
Third Party Transmission Expenses	**2018 Actual**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
JPZ Payments (NSP and GRE Zones)	$ 58,636	$ 60,181	$ 55,412	$ 59,439	$ 60,608
MISO Network Service, Point to Point, and Ancillary Services	$ 20,565	$ 18,438	$ 21,738	$ 21,876	$ 22,262
MISO Admin Charges (Sch. 10)	$ 11,674	$ 10,807	$ 10,812	$ 10,918	$ 11,564
Other (Transmission Facilities/Other Native Load Deliveries, etc.)	$ 171	$ 146	$ 179	$ 181	$ 184
Total Third-Party Expenses	$ 91,047	$ 89,572	$ 88,141	$ 92,413	$ 94,617
Wholesale Transmission Revenues	**2018 Actual**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
JPZ Revenues (NSP and GRE Zones)	$ 49,926	$ 55,129	$ 48,861	$ 54,356	$ 55,913
MISO Network Service	$ 26,017	$ 28,020	$ 30,863	$ 28,052	$ 28,894
MISO Point to Point	$ 8,054	$ 7,882	$ 7,334	$ 7,341	$ 7,349
GFAs	$ 407	$ 407	$ 414	$ 417	$ 420
Other (Ancillary Services/LBA Services, etc.)	$ 2,038	$ 1,776	$ 1,878	$ 1,910	$ 1,945
Total Third-Party Revenues	$ 86,443	$ 93,213	$ 89,350	$ 92,076	$ 94,521
Net Expense (Revenue)	$ 4,604	$ (3,641)	$ (1,209)	$ 337	$ 97

Since NSPM and NSPW operate the NSP System as an integrated system, the table above reflects NSP System revenues and expenses. The third-party transmission expenses and revenues are described in more detail later in my testimony and in Exhibit___(IRB-1), Schedules 4 and 5. The 2020 budget shows net revenue which serves to reduce the Company's overall retail cost of service.

Q. DO THE TRANSMISSION EXPENSES YOU DESCRIBE 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 an MVP. 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 and 26A revenues in the TCR Rider as an offset to Schedules 26 and 26A expenses paid to MISO.

Q. PLEASE DESCRIBE THE 2020, 2021, AND 2022 NSP SYSTEM THIRD-PARTY TRANSMISSION EXPENSES.

A. There are several types of third-party costs, which are summarized in Exhibit ___(IRB-1), Schedule 4. These are NSP System transmission costs necessary to serve NSP System loads, including NSP retail native loads in Minnesota, pursuant to rate schedules accepted for filing by FERC. My testimony provides the NSP System costs; Mr. Halama's cost of service reflects the portion allocated to the Minnesota jurisdiction.

- *JPZ Costs* – As I previously discussed, the NSP System incurs costs for serving its native loads within the NSP Joint Pricing Zone and in the GRE Joint Pricing Zone. The Company, GRE, Southern Minnesota Municipal Power Agency (SMMPA), Central Minnesota Municipal Power Agency (CMMPA), Northwestern Wisconsin Electric Company (NWEC), Minnesota Municipal Power Agency (MMPA), Missouri River Energy Services (MRES), and Rochester Public Utilities (RPU) each own transmission facilities and serve loads in the NSP pricing zone. The Company's payments consist of both expense and revenue components. The 2020-2022 expense is for our use of the GRE, SMMPA, CMMPA, NWEC, MMPA, MRES, and RPU transmission facilities to serve the NSP System loads in the NSP pricing zone. The revenue reflects use of the NSP System facilities by other utilities to serve their respective loads in the NSP zone. The NSP System 2020, 2021, and 2022 net payment under the NSP-JPZ arrangement is forecast to be \$8.3 million, \$6.7 million, and \$6.3 million, respectively, based on the JPZ expense and JPZ revenue summarized in Table 12 below.

Table 12

(Dollars in Millions)

Joint Pricing Zone – NSP Zone			
	Revenue	**Expense**	**Net Payment**
2020	\$ 42.9	\$ 51.2	\$ (8.3)
2021	\$ 48.2	\$ 54.9	\$ (6.7)
2022	\$ 49.5	\$ 55.9	\$ (6.4)

Similarly, the NSP System has both native load and transmission facilities located in the GRE pricing zone, which is also a multi-utility zone. The Company pays GRE a net payment consisting of expense and revenue components: the expense of using other parties' facilities to serve the Company's native load; and the revenue paid by other parties for their use of NSP's facilities in the GRE zone. The NSP System 2020, 2021, and 2022 net receipt for the GRE JPZ is forecast to be $1.7 million, $1.6 million, and $1.7 million, respectively, based on the JPZ expense and JPZ revenue summarized in Table 13 below.

Table 13

(Dollars in Millions)

Joint Pricing Zone - GRE Zone			
	Revenue	**Expense**	**Net Receipt**
2020	$ 6.0	$ 4.3	$ 1.7
2021	$ 6.2	$ 4.6	$ 1.6
2022	$ 6.4	$ 4.7	$ 1.7

Thus, the combined 2020, 2021, and 2022 impact of both the NSP JPZ and GRE JPZ is a net payment of $6.6 million, $5.1 million, and $4.7 million based on total expense and revenue summarized in Table 14 below and in Exhibit ___(IRB-1), Schedule 6.

Table 14

(Dollars in Millions)

Joint Pricing Zone - NSP and GRE Zones			
	Revenue	**Expense**	**Net Receipt**
2020	$ 48.9	$ 55.5	$ (6.6)
2021	$ 54.4	$ 59.5	$ (5.1)
2022	$ 55.9	$ 60.6	$ (4.7)

- *Network Integration Transmission Service (NITS) Costs* – The NSP Companies currently incur costs under the MISO Tariff for Reactive Supply and Voltage Control ancillary service needed by the NSP System to serve native load within the NSP pricing zone. The NSP Companies also incur costs under the MISO Tariff for services needed to serve other native loads that are within MISO, but located outside of the NSP pricing zone or GRE zone. These services include NITS service to serve Company loads in the Dairyland Power Cooperative, ITC Midwest, and Minnesota Power pricing zones, and charges for ancillary services for Company loads in the Otter Tail Power pricing zone. The MISO Tariff also requires the Company to use MISO PTP services to export power supply resources to the Company's native load in Berthold, North Dakota, outside the MISO region. The NSP System 2020, 2021, and 2022 payments to MISO for these services are forecasted to be $21.8 million, $21.9 million, and $22.2 million, respectively.
- *MISO Administrative Charges* – MISO charges its transmission service customers, such as the NSP System, its Schedule 10 administrative charge to recover the costs of administering its Tariff and providing other transmission functions. The 2020, 2021, and 2022 charges of $10.8 million, $10.9 million, $11.6 million, respectively, are based on the MISO's forecast of its Schedule 10 rate.
- *Other Transmission Expense/Facility Charges.* The NSP Companies incur these costs to secure delivery rights for the integration of NSP System loads. This cost consists of payments to Dairyland Power Cooperative, Minnkota Power Cooperative, McLeod Cooperative Power Association, Redwood Electric Cooperative, Stearns Electric

Association, and SPP (point-to-point transmission service), for use of their respective facilities to enable the Company to serve certain native loads. The NSP System 2020, 2021, and 2022 payments to these entities are forecast to be $178,500, $180,600, and $183,900, respectively.

Q. WHAT ARE THE 2020, 2021, AND 2022 WHOLESALE TRANSMISSION REVENUES?

A. As shown in Table 13, the total NSP System 2020 test year wholesale revenues are estimated to be $89.3 million, a 3.21 percent increase compared to 2018. The NSP System wholesale revenues for the 2021 and 2022 plan years are estimated to be $92.1 million and $94.5 million. Exhibit___(IRB-1), Schedule 5 provides more detailed information on the various transmission service revenues by type of service (NITS, point-to-point, etc.) for 2018 and 2020, 2021, and 2022. The revenues from these wholesale services are reflected as revenue credits in the cost of service study supported by Mr. Halama, thereby offsetting some of the third-party transmission expenses and reducing total costs to our Minnesota customers.

Q. HOW ARE THE WHOLESALE TRANSMISSION REVENUES KEPT ACCURATE AND CURRENT?

A. The NSP Companies update their MISO Attachment O ATRR every year. This update is 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. The 2020 NSP System ATRR, which reflects our 2020 projected revenue requirement and a true-up of 2018 revenues and loads, is now under review by MISO. The preliminary 2020 ATRR is $346.5 million, an increase from approximately $338.2 million in 2018, and will result in higher MISO zonal transmission service revenues.

C. Pending FERC ROE Proceedings

Q. PLEASE EXPLAIN THE BACKGROUND OF THE PENDING FERC ROE PROCEEDINGS IN FERC DOCKET NOS. EL14-12-000 AND EL15-45-000.

A. On November 12, 2013, a group of industrial customers in the MISO region filed a complaint (FERC Docket No. EL14-12, or the "First Complaint") asking FERC to reduce the base rate of ROE used in the transmission formula rates of jurisdictional MISO transmission owners, including the NSP Companies, from 12.38 percent to 9.15 percent. On September 28, 2016, the FERC issued an order (the "September 2016 Order") based on its methodology originally adopted in FERC Opinion 531, a case involving the base ROE for transmission owners in the New England ISO. In the September 2016 Order, the FERC ordered the base ROE to be set at 10.32 percent, with that rate applying to the EL14-12 refund period (November 12, 2013 to February 10, 2015) and prospectively from the date of the Order. Per the September 2016 Order, refunds were issued during the first half of 2017; however, multiple parties requested rehearing of the September 2016 Order, and those requests for rehearing remain pending before the FERC.

In February 2015, due to the impending expiration of the 15-month statutory limit on refund periods for complaints under section 206 of the Federal Power Act, a second Complaint (FERC Docket No. EL15-45, the "Second Complaint", or, together with the First Complaint, the "MISO ROE Complaints") was filed proposing to reduce the base ROE from 12.38 percent to 8.67 percent. The Second Complaint created a period of potential refunds from February 12, 2015 to May 11, 2016.

In June 2016, based on the Opinion 531 methodology, the ALJ recommended a base ROE of 9.70 percent, the midpoint of the upper half of the discounted cash flow (DCF) range (ALJ Recommendation). Multiple parties filed exceptions to the ALJ's Recommendation, and the complaint is pending action by the FERC.

On April 14, 2017, the United States Court of Appeals, D.C. Circuit (D.C. Circuit Court) vacated and remanded Opinion 531, finding that the FERC had not properly established that the existing ROE was unjust and unreasonable and also failed to adequately support the newly approved base ROE. As the September 2016 Order and ALJ Recommendation both cited Opinion 531 as the basis for the respective decisions, the ultimate outcome of the First Complaint and Second Complaint are expected to be impacted by FERC's response to the D.C. Circuit Court's decision.

In October 2018, the FERC issued an order in the New England ISO case addressing the D.C. Circuit Court's actions. As Company witness Mr. John Reed discusses in his Direct Testimony, under a newly-proposed, two-step ROE approach, the FERC indicated an intention to first assess whether an existing base ROE is unjust and unreasonable by establishing a range of reasonableness based on equal weighting of the DCF model, Capital Asset Pricing Model, and Expected Earnings model, and to dismiss an ROE complaint if the existing ROE falls within the resulting range of just and reasonable ROEs. Second, if necessary, the FERC would then set a new ROE by averaging the results of these models, plus a Risk Premium model. This proposed methodology differs significantly from the FERC's previous reliance entirely on the DCF model. Prior to the FERC establishing a new ROE based on its newly-proposed methodology, the FERC ordered parties in that case to file briefs regarding application of the new approach.

On November 15, 2018, the FERC issued an order in the MISO ROE Complaints proposing to apply the same methodology previously presented in the October 2018 order in the New England ISO case and ordering parties in the MISO ROE Complaints to file briefs on its application to the pending cases. The FERC's preliminary determinations indicated that the MISO TO's base ROE in effect for the First Complaint period (12.38 percent) was outside the range of reasonableness and, based on initial application of its proposed four-model average, should be reduced to 10.28 percent instead of the previously ordered base ROE of 10.32 percent. The ordered briefings were filed in February and April 2019, with parties advocating a variety of potential outcomes. The cases remain pending FERC action.

Q. WHAT IS THE NSP COMPANIES' MOST RECENT FERC-APPROVED ROE AT THIS TIME?

A. The most recent FERC order establishing a new base ROE for the NSP Companies is the FERC's September 2016 Order in the First Complaint, which set the base ROE at 10.32 percent. Although that Order remains subject to change from ongoing litigation, billed rates are currently based on that Order and use a total ROE of 10.82 percent (10.32 percent base ROE, plus a 50 basis point incentive adder for RTO participation).

Q. ARE THERE OTHER PENDING FERC PROCEEDINGS THAT COULD IMPACT THE FERC-JURISDICTIONAL TRANSMISSION ROE EARNED BY THE NSP COMPANIES?

A. Yes. On March 21, 2019, the FERC announced a general Notice of Inquiry (NOI) seeking public comments on whether, and if so how, to revise ROE policies in light of the D.C. Circuit Court decision.[5] This gives interested parties not involved in the New England ISO cases or the MISO ROE Complaints the opportunity to also comment on the FERC's proposed methodology for evaluating ROE complaints and establishing authorized base ROEs. Concurrently, the FERC also initiated an NOI on whether to revise its policies on incentives for electric transmission investments, including the incentive adder for RTO membership.[6] Initial comments on both NOIs were due in June 2019, with reply comments due in July and August of 2019. The timing and scope of potential FERC action as a result of these NOIs is uncertain but could include changes in the proposed methodology for establishing the base ROE and/or to ROE-related transmission incentives, such as the RTO participation adder.

Q. DOES THE COMPANY HAVE CERTAINTY AT THIS POINT AS TO THE FINAL MISO ROE THAT WILL BE ADOPTED BY THE FERC?

A. Not at this time. As evidenced by the multiple complaints and NOIs that are currently pending, there is still quite a bit of uncertainty as to the final ROE that will be adopted by the FERC.

[5] *See* FERC Docket No. PL19-4

[6] See FERC Docket No. PL19-3

Q. WHAT HAS BEEN THE IMPACT OF THE MISO ROE COMPLAINTS ON NSPM'S FINANCIAL RESULTS FOR ITS MINNESOTA ELECTRIC JURISDICTION?

A. In previous Minnesota rate cases, the transmission revenue credit, which represents the pass-through to retail customers of revenues received for providing transmission service to other utilities, resulting in a reduction to the cost of service, has been calculated using the previously-effective MISO ROE of 12.38 percent. However, since November 2013, those revenues have been subject to refund, and, in fact, the Company has issued initial refunds for the time period from November 2013 through February 2015. As a result, the transmission revenues actually earned have fallen short of the level credited to Minnesota retail customers, causing financial loss to the Company.

Q. IS THERE A TRUE-UP MECHANISM TO PROTECT THE COMPANY AND RETAIL CUSTOMERS FROM THE FINANCIAL IMPACTS RESULTING FROM CHANGES TO THE MISO ROE DUE TO THE MULTIPLE PENDING FERC PROCEEDINGS?

A. No, at least not for transmission revenues credited to customers through base rates. Certain types of transmission revenue are credited to customers through the TCR Rider, which includes a true-up to ensure customers are credited with the actual amount, no more and no less, of the revenues received. However, for items included in base rates, there has been no true-up mechanism in place.

Q. CAN YOU QUANTIFY THE AMOUNT OF LOSSES EXPERIENCED BY THE COMPANY AS A RESULT OF THE DIFFERENCE BETWEEN THE ULTIMATE FERC ROE AND THE ROE USED TO CALCULATE THE MINNESOTA REVENUE CREDIT?

A. As I discussed previously, the ultimate outcome of the MISO ROE Complaints, including refunds for the time period since November 2013, is uncertain at this time. However, Table 12 below summarizes the estimated impact, on a Minnesota jurisdictional basis, to the level of the Company's transmission revenues included as a revenue credit in its base rates between the 12.38 percent ROE utilized in previous rate cases and the 10.28 percent base ROE (10.78 percent for periods after January 6, 2015, including the 50 basis point RTO participation adder) proposed in the FERC's November 2018 order:

Table 15

Estimated Impact of ROE on Transmission Revenues

(MN Jurisdiction)

Year	**12.38% vs. FERC proposed outcome ($000s)**
2013	$547
2014	$4,644
2015	$4,042
2016	$2,613
2017	$3,974
2018	$3,409
2019	$3,423
Total	**$22,652**

Thus, the Minnesota jurisdiction has received a revenue credit of approximately $22.7 million in excess of the transmission revenue earned from 2013 to 2019.

Q. WHAT DOES THE COMPANY RECOMMEND WITH RESPECT TO THE TRANSMISSION REVENUE CREDIT IN THIS CASE?

A. As discussed by Mr. Halama, the Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base. Therefore, the transmission revenue credit has been calculated using the Company's most recently approved ROE of 9.06 percent as approved by the Commission in the Company's latest TCR Rider proceeding.[7] The Company further proposes to make an adjustment as part of its compliance filings to reflect the final authorized ROE in this case.

Q. WHAT IS THE IMPACT OF A LOWER FERC AUTHORIZED ROE?

A. For the 2020 test year, a 10 basis point (0.1 percentage point) reduction in the FERC authorized ROE is estimated to result in a reduction in wholesale transmission revenues, net of third-party transmission expenses, of approximately $400,000. This amount excludes revenues and expenses under MISO Schedules 26 and 26A, which are excluded from base rates and instead included in the TCR Rider.

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[7] *In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor*, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS, Docket No. E002/M-17-797 (Sept. 27, 2019).

D. Other Adjustments

Q. DO YOU PROPOSE ANY OTHER ADJUSTMENTS TO THE COMPANY'S WHOLESALE TRANSMISSION REVENUE AND EXPENSES FORECAST FOR PURPOSES OF THIS CASE?

A. Yes. The Company's transmission revenue and expense forecast for 2020 includes the recoupment of $3.8 million from GRE related to a 2019 dispute regarding GRE's transmission formula rate. The amounts involved relate to 2019, outside the time period covered by this case, were originally paid in 2019 by NSP subject to an ongoing dispute, and were never included in Minnesota retail rates. Therefore, the recoupment of such amounts, which is forecasted to occur during 2020, should be excluded for ratemaking purposes in this case.

Q. CAN YOU DESCRIBE THE NATURE OF THE DISPUTED CHARGES?

A. As previously mentioned, in order to serve its native load, NSP takes transmission service in pricing zones where GRE owns transmission assets. Therefore, NSP pays a portion of GRE's transmission formula rate. When GRE posted its 2019 projected rate, including its 2017 annual true-up (the effect of which is included in 2019 billed rates), GRE, for the first time, included a provision for income taxes as a component of the rate. As a not-for-profit cooperative corporation, it is our understanding that GRE does not incur income tax expense, and thus NSP disputed the rate.

In May 2019, NSP and GRE signed a Letter of Agreement, whereby GRE agreed to remove the income tax amounts from its 2019 projected rate, including the 2017 true-up. However, GRE's FERC-approved Annual True-Up, Information Exchange, and Challenge Procedures preclude mid-year rate changes. Thus, GRE is expected to include an adjustment in its 2020 rates to refund excess amounts collected during 2019.

Q. WHY DOES THIS IMPACT THE COMPANY'S 2020 FORECAST INSTEAD OF 2019?

A. Generally Accepted Accounting Procedures (GAAP) required NSP to record an expense for the amounts billed by GRE in 2019, despite them being under dispute. Further, although the Company was able to reach a settlement with GRE in May 2019, GAAP precludes accounting for that benefit until the funds are received in 2020. Therefore, NSP has included receipt of those funds in its 2020 corporate forecast. However, as mentioned previously, the amounts relate to 2019, outside the time period covered by this case, were originally paid in 2019 by NSP subject to an ongoing dispute, and were never included in Minnesota retail rates. Therefore, the recoupment of such amounts should be excluded for ratemaking purposes in this case.

VI. TRANSMISSION SYSTEM LINE LOSS ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In its June 12, 2017 Order in our last electric rate case, the Commission determined that the consideration of line losses—the amount of energy that is lost through the process of transmission and distribution—may further enhance the accuracy of the Class Cost of Service Study.[8] As a result, the Commission directed the Company to report in its next rate case on methods to conduct loss studies to measure line losses. The two general categories of losses on the Xcel Energy system are transmission losses and distribution

[8] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 49 (June 12, 2017).

losses. I will discuss the methods for measuring transmission losses, while Company witness Ms. Kelly A. Bloch discusses the methods for measuring distribution losses in her Direct Testimony.

Q. WHAT ARE ELECTRIC LOSSES?

A. The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class's total peak is reached.

Q. DOES THE COMPANY HAVE THE CAPABILITIES TO MEASURE ACTUAL LOSSES ON THE TRANSMISSION SYSTEM?

A. The Company does have the data and the theoretical ability to identify actual transmission losses across the transmission system on an hourly basis. Processing the data for this purpose, however, would require months of manual processing.

Q. WHAT TYPE OF DATA DOES XCEL ENERGY COLLECT REGARDING ACTUAL TRANSMISSION SYSTEM LOSSES?

A. At the beginning of 2013, Xcel Energy began storing hourly losses on transmission lines and transformers. Those transmission losses are calculated by a computer program called the "state estimator," which is basically an on-line power flow program. The state estimator is fed actual data, generally at four second intervals, supplied from Xcel Energy's Energy Management System (EMS). The EMS is an integrated set of computer hardware, software, and computer programs which aid Company transmission system operators in viewing, monitoring, and operating the transmission system. Significant investment in communication infrastructure (Remote Terminal Units, communication systems to retrieve data, etc.), along with investments in computer hardware and software have made it possible to collect the data from the transmission system necessary to conduct the line loss analysis.

Q. HOW COULD THE DATA COLLECTED BY XCEL ENERGY BE USED TO CALCULATE ACTUAL LOSSES ON THE TRANSMISSION SYSTEM?

A. There are approximately 1,653 transmission lines and transformers for which transmission loss data is stored. In a typical year with 8,760 hours, that means there are approximately 14.5 million data rows for each year of data being processed. Although the data exists, much of the manipulation and investigation of the data requires manual human intervention to ensure we are accessing the correct data such as data for a given hour. The large data files that are generated by our EMS contain a variable number of rows of data for each day and hour. This makes summarizing and analyzing the data difficult to automate. We estimate it will take approximately 300 hours to process and analyze the transmission losses by hour and align those results with hourly load data provided by other parts of the Company.

Q. HAS THE COMPANY ESTIMATED THE COSTS TO PROCESS THIS TRANSMISSION LOSS DATA?

A. The Company estimates the cost to process the data, including hiring some external engineering resources to assist in analyzing the data, at approximately $190,000.

Q. ARE THERE METHODS TO ESTIMATE TRANSMISSION SYSTEM LOSSES USING ACTUAL DATA?

A. Yes. As discussed above, the Company uses actual data from the Company's EMS to feed into a computer program called the state estimator, which is a powerflow program, pre-populated with some data necessary to calculate transmission losses such as actual transmission line and transformer resistance values, then the EMS data informs the state estimator using 4 second interval data and other information such as generation output levels and flows, which are the remaining data necessary to calculate transmission losses. Although transmission losses calculated from actual data exist, this large volume of transmission loss data still needs to be processed (i.e. processing the data to summarize and understand at which voltage levels the transmission losses occur since different customers take service at different voltage levels) if the Company is seeking to understand how losses vary hourly for various customer classes.

Q. ARE THERE METHODS TO ESTIMATE TRANSMISSION SYSTEM LOSSES IN THE ABSENCE OF USING ACTUAL DATA?

A. Yes. In the absence of using actual data, there are other methods to estimate transmission losses. The Company could perform or hire an engineering consultant to perform calculations of transmission losses on lines and transformers using transmission line and transformer resistance data, assumed generation outputs, and power transfer levels. Typically this type of study would be done for the transmission system by using a power flow program such as Siemen's PSS/E, since the transmission system is a network of power lines and transformers where the powerflow on a line is impacted by both customer electric load and also by power transfers across the system. In the absence of a powerflow program, it would be difficult to predict the current flow on each element in the transmission network. This type of off-line engineering study has some disadvantage compared to a study using actual data in that powerflow programs are designed to take a snapshot (similar to a picture) of the transmission system under one assumed condition, while the actual system conditions are varying as customer electric loads move up and down and power transfers move up and down as MISO dispatches the generation on an economic basis every five minutes.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The transmission organization constructs and maintains the transmission components for the NSP System that are necessary to enable the safe, reliable, and efficient delivery of energy from generating resources to customers. We anticipate completing $134.3 million of capital additions in 2020, $353.5 million in 2021, and $273.5 million in 2022 for NSPM. These capital additions include transmission projects for which we will seek rate recovery through the TCR Rider. These capital projects are needed to maintain the health of transmission facilities, meet reliability requirements, add capacity to support increasing amounts of new generation, interconnect new generators, and enable communication between our facilities.

We have budgeted $39.3 million for transmission O&M in 2020, $37.8 million in 2021, and $38.2 million in 2022. This is a decrease in O&M expenses as compared to our three-year historic average for 2016 to 2018 of $41.6 million.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications
Ian R. Benson

Current Responsibilities

My responsibilities include: supervising engineers in planning the electric transmission systems for the four Xcel Energy Inc. operating companies, NSPM, Northern States Power Company, a Wisconsin corporation (together the NSP Companies), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS); overseeing the development of local and regional transmission system plans, including coordinated joint planning with the Midcontinent Independent Transmission System Operator, Inc. (MISO), and other utilities to ensure reliable transmission service; recommending the construction of such plans to Xcel Energy Inc. management and MISO; participating in and supporting MISO sponsored transmission service studies, generation interconnection studies, long range regional plan development, load service planning and other transmission planning activities required by MISO to perform its obligations under the MISO Tariff and the MISO Transmission Owner's Agreement; and providing technical support for regulatory aspects of transmission system planning activities and contract development for the NSP Companies, PSCo, and SPS.

Education:

Bachelor of Geological Engineering - 1984
University of Minnesota

Bachelor of Science, Mathematics – 1991
University of Minnesota

Master of Business Administration – 2010
University of St Thomas

Previous Employment (1991 to 2010):

Senior Engineer - Northern States Power Company (1991 – 1994)
Lead Sales Representative - Northern States Power Company (1994 – 1998)
Mid-Term Marketing Representative - Northern States Power Company (1998 – 1999)
Manager, Mid-Term Markets - Northern States Power Company (1999 – 2000)
Director, Origination - Xcel Energy Services Inc. (XES) (2000 – 2004)
Director, Transmission Access - XES (2004 – 2009)
Director, Transmission Investment Development - XES (2009 – 2010)
Director, Transmission Business Relations and Asset Management - XES (2010 – 2013)
Director, Transmission Planning and Business Relations - XES (2013 – 2016)
Area Vice President, Transmission Strategy and Planning – XES (2016 – present)

U.S. Navy

Active Duty: 1984 to 1989
Naval Reserve: 1989 to 2006

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2020		2021		2022		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Regional Expansion	Huntley Wilmarth Precertification*	A.0000835.001	Huntley Wilmarth Precertification	0	0	1	0	0	0	12/30/2021
Regional Expansion	Huntley Wilmarth Precertification*	A.0000835.003	Huntley Wilmarth 345 ROW N/S	3,504	2,559	1,016	742	0	0	12/31/2021
Regional Expansion	Huntley Wilmarth Precertification*	A.0000835.004	Huntley Wilmarth 345 Line N S	0	0	71,825	52,448	1,250	913	12/31/2021
Regional Expansion	Google Interconnection	A.0001365.001	0827 SCL SNL	1,201	877	0	0	0	0	6/15/2020
Regional Expansion	Google Interconnection	A.0001365.002	0827 SNL LIB	0	0	0	0	520	379	7/15/2022
Regional Expansion	Google Interconnection	A.0001365.003	5573 SNL SHC	0	0	0	0	520	379	7/15/2022
Regional Expansion	Google Interconnection	A.0001365.004	5574 SNL SHC	0	0	0	0	520	379	7/15/2022
Regional Expansion	Google Interconnection	A.0001365.005	Snuffys Landing Sub	0	0	0	0	12,527	9,148	7/15/2022
Regional Expansion Total				**4,705**	**3,436**	**72,842**	**53,190**	**15,336**	**11,198**	
Reliability Requirement	0714:MDE(ITC)MDL(City)Tap Rbld	A.0000727.001	Line 714 rebuild Line	0	0	0	0	1,609	1,175	12/1/2022
Reliability Requirement	Aldrich	A.0000986.001	Aldrich DCP Upgrade Feeders, Sub	0	0	1,015	741	0	0	6/1/2021
Reliability Requirement	Black Dog-Wilson 115kV uprates	A.0000155.002	Black Dog Wilson 115kV Uprates Sub	0	0	5,118	3,737	0	0	3/1/2021
Reliability Requirement	Cannon Falls Retaining Wall	A.0000725.001	(TBD)Cannon Falls Site Imprvmn	331	242	0	0	0	0	1/15/2020
Reliability Requirement	Falls Capacitor Bank	A.0001185.001	Falls 40MVAR Cap Bank Sub	0	0	0	0	1,944	1,419	6/1/2022
Reliability Requirement	Forbes Substation SVC Retire	A.0001179.001	FBS Retire Forbes SVC	0	0	1,469	1,072	0	0	12/15/2021
Reliability Requirement	HIBTAC 500kV	A.0000901.001	HIBTAC 500kV Relocation Line	0	0	15,545	11,351	0	0	12/1/2021
Reliability Requirement	Hollydale - TAM/DCP	A.0000226.013	Hollydale TR Expansion TAM	1,761	1,286	10	7	0	0	12/1/2020
Reliability Requirement	Hollydale - TAM/DCP	A.0000226.021	Line5409 In/Out at HOL	0	0	534	390	0	0	12/1/2021
Reliability Requirement	Lincoln County Capacitor Bank	A.0001184.001	Lincoln Co 30MVAR Cap Bank Sub	0	0	1,676	1,224	0	0	6/1/2021
Reliability Requirement	MnTACT	A.0000943.007	2020 NSPM NERC TPL(MN-TACT)	4	3	4	3	4	3	12/31/2024
Reliability Requirement	MnTACT	A.0000943.008	2021 NSPM NERC TPL (MN-TACT)	0	0	3,771	2,753	8,191	5,981	12/31/2023
Reliability Requirement	NSPM Galloping Conductors	A.0000714.003	NSPM 2019 Galloping Mitigation	0	0	1,501	1,096	0	0	12/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.008	NSM5531 Galloping Mitigation L	0	0	3,187	2,327	0	0	12/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.010	NSM5545 Galloping MitigationLi	0	0	465	340	0	0	2/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.014	NSM5547 Galloping Mitigation Line	0	0	1,308	955	0	0	2/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.015	NSM0825 Galloping Mitigation Line	0	0	458	335	0	0	2/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.016	NSM5538 Galloping Mitigation Line	0	0	2,115	1,545	0	0	12/15/2021
Reliability Requirement	NSPM Galloping Conductors	A.0000714.017	NSM5545 Galloping Mitigation Line	0	0	0	0	1,617	1,181	2/15/2022
Reliability Requirement	NSPM Galloping Conductors	A.0000714.020	NSM5538 Galloping Mitigation Line S	0	0	1	1	0	0	2/15/2021
Reliability Requirement	Prairie Substation Capbank Remove	A.0001178.001	Prairie Sub Remve 40 MVAR Capbank	0	0	0	0	726	530	12/15/2022
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.001	ASK-Repl/Add DFR shelves	0	0	103	75	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.002	BLL-Repl/Add DFR shelves	0	0	103	75	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.003	RRK-Repl/Add DFR shelves	0	0	102	75	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.004	TER-Repl/Add DFR shelves	0	0	103	75	0	0	6/15/2021
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.005	WLM-Repl/Add DFR shelves	0	0	99	73	0	0	6/15/2021
Reliability Requirement	Red Rock 345kV BusDiffRly	A.0000726.001	Red Rock Bus Differential Rela	0	0	707	516	0	0	6/1/2021
Reliability Requirement	Rosemount Sub	A.0000715.001	Rosemount TR2 Sub	0	0	1,319	964	0	0	12/1/2021
Reliability Requirement	South Washington ERU	A.0010148.007	South Washington Sub In Out	611	446	2	1	0	0	11/20/2020
Reliability Requirement	South Washington ERU	A.0010148.008	South Washington Sub TAM	1,610	1,176	20	15	0	0	11/20/2020
Reliability Requirement	Stockyards Sub	A.0000718.001	Stockyards DCP TR3 Sub	0	0	1,245	909	2	1	10/15/2021
Reliability Requirement	Stockyards Sub	A.0000718.002	0818/5529 Tap Relo Line	0	0	141	103	0	0	10/15/2021
Reliability Requirement	Twin Cities Fault Current	A.0000595.001	Twin Cities Fault Current Sub Term	0	0	0	0	0	0	1/15/2020
Reliability Requirement	Wilmarth - TC Thru Flow Mitigation	A.0000385.001	Line 0717 GRI to CAR Rbld Line	0	0	0	0	4,185	3,056	3/1/2022
Reliability Requirement	Wilmarth/Mankato Energy Center Trans. Pr	A.0000660.001	ARL Main Bus Reconfig(USE) Sub	0	0	0	0	1,263	923	5/31/2022
Reliability Requirement	Wilmarth/Mankato Energy Center Trans. Pr	A.0000660.003	GRI Trans DE and Switches Sub	0	0	0	0	1,035	756	3/1/2022
Reliability Requirement	Wilson Substation Conversion	A.0000390.001	Wilson Breaker & 1/2 Sub	0	0	14,832	10,831	0	0	2/1/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.002	Black Dog Relay Replacement Su	863	630	0	0	0	0	6/15/2020
Reliability Requirement	Wilson Substation Conversion	A.0000390.003	NIne Mile Creek Relaying Sub	14	10	0	0	0	0	3/30/2020

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	WBS Level 2 #	Description	Addition Amount ($000s) 2020 NSPM	2020 MN Jur	2021 NSPM	2021 MN Jur	2022 NSPM	2022 MN Jur	In-Service Date
NSPM Additions										
Reliability Requirement	Wilson Substation Conversion	A.0000390.004	East Bloomington Relaying Sub	281	205	0	0	0	0	6/15/2020
Reliability Requirement	Wilson Substation Conversion	A.0000390.009	Line 0808 EBL Reterminate at WL	0	0	1,629	1,189	0	0	3/15/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.010	Line 0857 BDS NMC Reterminate at WL	0	0	1,780	1,300	0	0	3/15/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.011	Line 0816 NMC Reterminate at WL	0	0	2,276	1,662	0	0	3/15/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.012	Line 0815 BDS Reterminate at WL	0	0	876	639	0	0	1/15/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.013	WilSub Breaker and Half Comm	0	0	197	144	0	0	6/15/2021
Reliability Requirement	Wilson Substation Conversion	A.0000390.016	Line 0857-WIL to BDS OPGW	0	0	0	0	0	0	3/30/2020
Reliability Requirement Total				**5,475**	**3,998**	**63,710**	**46,522**	**20,576**	**15,025**	
Asset Renewal	0953 Replace OPGW	A.0001299.002	NSM0953 NOB SPK Repl OPGW MN	0	0	9076	6627	0	0	7/15/2021
Asset Renewal	BNSF Fridley Mitigation Line	A.0001211.001	BNSF Fridley Mitigation Line	285	208	0	0	0	0	6/30/2020
Asset Renewal	ELR - Breakers - NSPM	A.0000394.016	Souris - Repalce Breaker 5T70	0	0	0	0	347	253	10/31/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.026	Fifth St-Replace Bkrs 5M760,5M765,5	0	0	1329	971	0	0	12/15/2021
Asset Renewal	ELR - Breakers - NSPM	A.0000394.027	Hugo-Replace Bkrs 5P196 & 5P197	0	0	0	0	873	637	12/15/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.028	Inver Grove-Replace 4P8,4P9,4P10	0	0	0	0	877	640	12/15/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.031	Arlington-Replace Bkrs 4S191,4S192,	355	259	0	0	0	0	12/15/2020
Asset Renewal	ELR - Breakers - NSPM	A.0000394.032	Rogers Lake-Replace Bkr 5P69	366	267	0	0	0	0	5/15/2020
Asset Renewal	ELR - Breakers - NSPM	A.0000394.033	Rose Place-Replace Bkr 5P50	469	343	0	0	0	0	6/15/2020
Asset Renewal	ELR - Relay - NSPM	A.0000395.028	Red Rock Relaying - CGR CRY-RF	476	348	0	0	0	0	10/15/2020
Asset Renewal	ELR - Relay - NSPM	A.0000395.032	Cottage Grove Relaying - CHE R	442	323	0	0	0	0	5/15/2020
Asset Renewal	ELR - Relay - NSPM	A.0000395.061	Airport Relaying - RLK	351	256	0	0	0	0	12/15/2020
Asset Renewal	ELR - Relay - NSPM	A.0000395.064	Elliot Park Relaying-MST,RIV	0	0	700	511	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPM	A.0000395.065	Fifth St Relaying - RIV	0	0	355	259	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPM	A.0000395.068	Lincoln Co Relaying - CHC,CEN	556	406	0	0	0	0	12/15/2020
Asset Renewal	ELR - Relay - NSPM	A.0000395.069	Main St Relaying - ELP,RIV	0	0	800	584	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPM	A.0000395.071	Moore Lake Relaying - RIV	0	0	0	0	357	261	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.075	Riverside Relaying - MOL,TWL	0	0	0	0	702	513	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.076	Riverside Relaying-ELP,FST,MST	0	0	1029	751	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPM	A.0000395.077	Rogers Lake Relaying-AIR	434	317	0	0	0	0	12/15/2020
Asset Renewal	ELR - Relay - NSPM	A.0000395.080	Tanners Lake Relaying - WDY	0	0	396	289	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPM	A.0000395.081	Twin Lakes Relaying - RIV	0	0	0	0	327	239	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.090	Cedarvale Replace Relaying to BDS	0	0	0	0	356	260	12/15/2022
Asset Renewal	ELR - Transformers - NSPM	A.0000506.002	NSPM 2016 ELR Transformers, Su	50	37	3009	2197	3010	2198	12/15/2024
Asset Renewal	ELR Nuclear NSPM	A.0001014.001	NSPM - ELR - Nuclear	984	719	4531	3309	6787	4956	12/30/2024
Asset Renewal	Fault Recorders - NSPM	A.0000393.006	Eden Prairie Fault Record Comm	0	0	393	287	0	0	12/20/2021
Asset Renewal	Fault Recorders - NSPM	A.0000393.007	Kohlman Lk Fault Recorder Comm	0	0	463	338	0	0	12/20/2021
Asset Renewal	Fault Recorders - NSPM	A.0000393.008	Elm Creek - Install Fault Recorder	0	0	420	307	0	0	11/30/2021
Asset Renewal	Fault Recorders - NSPM	A.0000393.009	Inver Hills - Install Fault Recorde	0	0	348	254	0	0	11/30/2021
Asset Renewal	Line ELR - NSPM	A.0000504.025	NSPM T-Line ELR 2016 69kV, Line	2064	1507	3417	2495	3520	2570	12/15/2024
Asset Renewal	Line ELR - NSPM	A.0000504.039	ND 69kV T-line ELR, Line	101	73	100	73	100	73	12/31/2024
Asset Renewal	Line ELR - NSPM	A.0000504.043	SD 69kV T-line ELR, Line	101	73	100	73	100	73	12/31/2024
Asset Renewal	NSP Line Capacity	A.0000233.005	Line Capacity-MN Line	10	7	10	7	0	0	12/1/2021
Asset Renewal	NSP Reloc B	A.0000276.026	NSPM Reloc B 69kV Line	1477	1079	1477	1078	1477	1079	12/21/2024
Asset Renewal	NSP Reloc B	A.0000276.035	ND Reloc B 60kV Line	50	37	50	37	50	37	12/15/2024
Asset Renewal	NSP Reloc B	A.0000276.039	NSPM Reloc B 345kV, Line	0	0	0	0	0	0	4/30/2020
Asset Renewal	NSP Reloc B	A.0000276.056	SD Reloc B 69kV Line	50	37	50	37	50	37	12/15/2024
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.004	NSPM Major Line Refurbish	0	0	201	146	1873	1368	12/31/2024
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.008	772 - Prairie (Minnkota IA) -E	0	0	809	591	0	0	12/31/2021
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.013	786 - Minnkota - Larimore Line	0	0	884	646	0	0	12/31/2021

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2020		2021		2022		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.020	NSM0761 0739 Peoples T Mazeppa	0	0	0	0	1697	1239	3/31/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.022	NSPM0815 BDS -WIL 115kV Refurb	1139	832	0	0	0	0	4/30/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.024	NSM0752 Brooten Paynesville Refurb	2313	1689	0	0	0	0	1/15/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.025	NSM0734 West Gate Excelsor Line	0	0	3169	2314	0	0	12/15/2021
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.028	NSPM0857 BDS -NMC 115kV Refurb	1216	888	0	0	0	0	4/30/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.031	NSM0746 Prairie Minnkota Refurb	455	333	0	0	0	0	12/15/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.033	NSM0739 Kason Dodge Center Line	884	646	0	0	0	0	1/15/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.034	NSM0739 - Kasson-Pine Island,Line	1217	889	0	0	0	0	1/15/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.035	NSM0739 - Zumbrota - Kasson,Line	555	405	0	0	0	0	1/15/2020
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.037	NSM0735 CAR STB Refurb	0	0	0	0	180	132	12/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.038	NSM0735 CAR YAM Refurb	0	0	0	0	155	113	12/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.039	NSM0735 DLO STB Refurb	0	0	0	0	530	387	12/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.040	NSM0701 CRO to GFD Refurb	0	0	0	0	3665	2676	12/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.041	NSM5400 ALB-PAT-WAK Refurb	0	0	0	0	3480	2541	12/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.042	NSM0729 CLF LCO SOS Refurb	0	0	0	0	297	217	12/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.044	NSM0729 CEN LCO Refurb	0	0	0	0	3141	2293	12/15/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.006	NSPM Switch Replacements,	0	0	394	288	985	719	12/31/2024
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.015	Frontenac 541542 & 760 Line	425	311	0	0	0	0	12/1/2020
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.016	Zumbrota 206 207 &208 Line	0	0	0	0	404	295	12/31/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.019	Gleason Lake 4M58, Line	0	0	228	167	0	0	12/15/2021
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.020	Gleason Lake 4M17, Line	0	0	228	167	0	0	12/15/2021
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.021	Fairfax Muni Tap 450 453 Line	451	330	0	0	0	0	12/15/2020
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.022	Bush Park Munni 4N41 4N42 & 4N	0	0	415	303	0	0	12/15/2021
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.031	NSM0789 Wells Ck 4H21 4H22 4H2	0	0	438	320	0	0	12/15/2021
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.035	NSM0733 Reynolds Repl SW 130 131	343	251	0	0	0	0	10/15/2020
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.037	0733 Thompson Rpl SW 120 121	344	251	0	0	0	0	3/14/2020
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.041	NSPM 2017 GRE Switch Replacements 6	99	72	98	72	99	72	12/15/2024
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.048	NSM0719 Sleepy Eye switch	0	0	347	253	0	0	12/15/2021
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.050	NSM0752 Brooten 686 687Line	550	402	0	0	0	0	12/15/2020
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.056	NSM0793 Villard 4N33 4N34	0	0	355	259	0	0	12/15/2021
Asset Renewal	NSPM Major Line Rebuild	A.0000351.004	NSPM Major Line Rebuild,L	0	0	3596	2626	21594	15768	12/31/2024
Asset Renewal	NSPM Major Line Rebuild	A.0000351.013	NSM0795 West St Cloud Millwood Tap	0	0	0	0	18519	13523	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.016	NSM0779 - Canisota SalemLine	0	0	1961	1432	0	0	12/15/2021
Asset Renewal	NSPM Major Line Rebuild	A.0000351.022	NSM0808 AIR RLK Rebuild Line	0	0	4169	3044	0	0	12/15/2021
Asset Renewal	NSPM Major Line Rebuild	A.0000351.026	NSM0730 - West Sioux Falls - Line 7	0	0	2915	2129	0	0	12/31/2021
Asset Renewal	NSPM Major Line Rebuild	A.0000351.030	NSM0752 Belgrade - Paynesville Rebu	0	0	0	0	8342	6091	12/31/2022
Asset Renewal	NSPM Metro Steel pole Rplmnt	A.0000743.004	NSPM Triple Ckt Pole Repl 2016	412	301	2362	1725	1975	1442	12/31/2024
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.005	NSPM - 2016 - ELR - RTUComm	49	36	99	72	986	720	12/31/2024
Asset Renewal	S&E - NSP Line	A.0000177.043	NSPM S&E 69kV Line	2503	1828	3980	2906	3805	2778	12/31/2024
Asset Renewal	S&E - NSP Line	A.0000177.050	ND S&E B 69kV Line	100	73	100	73	100	73	12/31/2024
Asset Renewal	S&E - NSP Line	A.0000177.055	SD S&E B 69kV Line	100	73	100	73	100	73	12/15/2024
Asset Renewal	S&E - NSP Line	A.0000177.056	NSPM Priority Defects 69kV Line	976	713	976	713	976	713	12/30/2024
Asset Renewal	S&E - NSP Sub	A.0000585.008	ND 2016 S&E Sub	64	47	64	47	64	47	12/31/2024
Asset Renewal	S&E - NSP Sub	A.0000585.009	NSPM 2016 S&E Sub	707	516	706	516	707	516	12/31/2024
Asset Renewal	S&E - NSP Sub	A.0000585.013	SD 2016 S&E Sub	64	47	64	47	64	47	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.085	Tool Blanket MN Subs	120	88	130	95	130	95	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.087	NSPM Sys Protect Comm Eng Testing E	100	73	100	73	100	73	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.445	Tool Blanket MN Line	140	102	140	102	140	102	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.447	NSPM Training Center Tools	75	55	75	55	75	55	12/31/2024

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	WBS Level 2 #	Description	Addition Amount ($000s) 2020 NSPM	2020 MN Jur	2021 NSPM	2021 MN Jur	2022 NSPM	2022 MN Jur	In-Service Date
NSPM Additions										
Asset Renewal	Tools and Equipment	A.0006059.449	NSP COM Tool Sub	356	260	1400	1022	1000	730	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.450	NSP Ops Eng Ofc Eq	60	44	60	44	60	44	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.451	NSPM COM Tools (BU 8640)	135	99	135	99	135	99	12/31/2023
Asset Renewal	Tools and Equipment	A.0006059.452	Survey Group Tool B Line	60	44	60	44	50	37	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.453	Civil Dept Tool B Line	1351	987	2500	1826	2000	1460	10/30/2024
Asset Renewal	Tools and Equipment	A.0006059.496	EPZ Mats MN	50	37	250	183	50	37	12/31/2024
Asset Renewal	Tools STAC	A.0001019.001	NSPM Tools STAC	12	9	12	9	12	9	12/31/2024
Asset Renewal	Tools STAC	A.0001019.003	NSPM STAC Tools	12	9	12	9	12	9	12/31/2023
Asset Renewal	Transmission UAV Flights	A.0000855.001	NSPM Transmission UAV	0	0	8355	6101	0	0	10/30/2021
Asset Renewal	Unserviceable - Relays - NSPM	A.0000751.003	MN 2016 Unserviceable Relay Su	493	360	493	360	492	359	12/31/2024
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.018	MN 2016 Unserviceable Breaker	567	414	566	414	566	414	12/31/2024
Asset Renewal Total				**27,122**	**19,805**	**71,000**	**51,846**	**97,493**	**71,191**	
Communications Infrastructure	Comm Network Program	A.0001320.007	NSPM Comm Network Program Comm	197	144	2,461	1,797	7,399	5,403	12/15/2024
Communications Infrastructure	Comm Network Program	A.0001320.008	NSPM Comm Network Program Sub	197	144	2,463	1,799	7,391	5,397	12/15/2024
Communications Infrastructure	NSPM Comm Circuit Upgrades	A.0001357.002	NSPM 2017 COMM Circuit Upgrades	170	124	170	124	170	124	12/31/2023
Communications Infrastructure	NSPM Sub Communication Network Group 2	A.0000815.001	NSPM Sub Comm Network Group 2	1	1	0	0	0	0	1/15/2020
Communications Infrastructure	NSPM Sub Communication Network Group 2	A.0000815.002	NSPM Sub Comm Network Group 2	1	1	0	0	0	0	12/15/2019
Communications Infrastructure	NSPM Sub Communication Network Group 2	A.0000815.006	NSPM Sub Comm Group 2 Line	670	489	0	0	0	0	3/15/2020
Communications Infrastructure	St Cloud RTU Replacement	A.0001246.001	St Cloud Replacement	91	66	0	0	0	0	4/30/2020
Communications Infrastructure Total				**1,327**	**969**	**5,095**	**3,720**	**14,961**	**10,925**	
Interconnection	BLRT Blue line Extension	A.0000908.002	BLRT 0814 115kV Relocation	4	3	0	0	0	0	6/1/2020
Interconnection	BLRT Blue line Extension	A.0000908.003	BLRT 0805 115kV Relocation	5	3	0	0	0	0	6/1/2020
Interconnection	IA Tariff Fund	A.0000076.002	IA Tariff Fund NSP	1,538	1,123	2,966	2,166	4,096	2,991	12/31/2024
Interconnection	J512 FTN to NOB Wind Interc	A.0001245.004	J512 Zephyr Substation Network	6	4	0	0	0	0	7/1/2020
Interconnection	Jamaica Substation	A.0001379.002	Jamaica Substation TAM	1,524	1,113	0	0	0	0	9/1/2020
Interconnection	Jamaica Substation	A.0001379.004	0881 JAM CHE Connect Jamaica Sub	1,520	1,110	0	0	0	0	9/1/2020
Interconnection Total				**4,597**	**3,356**	**2,966**	**2,166**	**4,096**	**2,991**	
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.001	NERC 754 Protection Sys MNSub	0	0	7,081	5,171	3,898	2,847	10/30/2024
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.003	Prairie Island NERC Order 754 Upgra	1,437	1,050	0	0	0	0	9/15/2020
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.004	Monticello NERC Order 754 Upgrade	524	383	0	0	0	0	9/15/2020
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.008	Forbes 500kV NERC Order 754	0	0	190	139	0	0	12/15/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.010	Parkers Lake 345kV NERC Order 754	1,025	748	0	0	0	0	4/15/2020
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.011	Blue Lake 345kV NERC Order 754	0	0	227	166	0	0	12/15/2021
Physical Security and Resiliency	NERC Order 754 NSPM	A.0000738.016	Chisago 345kV NERC Order 754	0	0	305	223	0	0	12/15/2021
Physical Security and Resiliency	NSPM Electro Mag Pulse (EMP)	A.0000957.005	NSPM Electro Mag Pulse (EMP)	0	0	0	0	161	118	12/31/2022
Physical Security and Resiliency	NSPM Geomagnetic Disturbances (GMD)	A.0000752.006	NSPM Geo Mag Dist (GMD)	0	0	1,515	1,106	1,010	738	10/31/2024
Physical Security and Resiliency	Physical Security	A.0000710.004	NSPM Physical Security Sub Infrastr	6,443	4,705	6,207	4,532	6,257	4,569	12/31/2022
Physical Security and Resiliency	Physical Security	A.0000710.010	NSPM Physical Security Comm	1,283	937	1,256	917	851	621	12/30/2023
Physical Security and Resiliency	Physical Security	A.0000710.011	NSPM ND Physical Security Comm	0	0	65	48	453	331	9/30/2022
Physical Security and Resiliency Total				**10,713**	**7,823**	**16,846**	**12,302**	**12,631**	**9,223**	
NSPM Total				**53,938**	**39,387**	**232,459**	**169,746**	**165,093**	**120,554**	

**Those projects that will be recovered through the Transmission Cost Recovery Rider*

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2020		2021		2022		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Regional Expansion	La Crosse - Madison	A.0000306.002	LAX-MAD New 345kV Non Shared L	89	65	0	0	0	0	12/31/2018
Regional Expansion	La Crosse - Madison	A.0000306.008	3104 Lax-Mad 345 N/S ROW	489	357	0	0	0	0	12/31/2019
Regional Expansion	DCP Kinnickinnic	A.0001247.001	W3426 Reterm at Kin DCP	50	36	0	0	0	0	12/15/2020
Regional Expansion	DCP Kinnickinnic	A.0001247.002	Kin Rbld 69 23 9kV Sub TAM DCP	345	252	0	0	0	0	12/15/2020
Regional Expansion Total				**972**	**710**	**0**	**0**	**0**	**0**	
Reliability Requirement	Bayfield Loop	A.0000193.001	Bayfield Loop Sub	0	0	0	0	29,300	21,395	10/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.003	W3605 Iron River-Herbster Line	0	0	0	0	10,454	7,634	10/15/2022
Reliability Requirement	Bayfront to Ironwood 88 kV	A.0000567.006	W3351 BFT - IRW ROW	1,000	730	1,000	730	1,000	730	12/15/2022
Reliability Requirement	Bayfront to Ironwood 88 kV	A.0000567.009	BFT IRW Permit Line SAP	0	0	1,614	1,179	0	0	12/31/2021
Reliability Requirement	NSPW NERC TPL (MnTACT)	A.0000759.007	2021 NSPW NERC TPL (MN_TACT)	0	0	3,048	2,226	4,959	3,621	12/31/2024
Reliability Requirement	NSPW Galloping Conductors	A.0000762.001	NSPW 2019 Galloping Mitigation	0	0	1,384	1,010	0	0	3/31/2021
Reliability Requirement	NSPW Galloping Conductors	A.0000762.002	NSPW 2018 Galloping Mitigation	3,017	2,203	0	0	0	0	9/15/2020
Reliability Requirement	NSPW Galloping Conductors	A.0000762.008	W3217 Galloping Mitigation	3,281	2,395	0	0	0	0	5/15/2020
Reliability Requirement	NSPW Galloping Conductors	A.0000762.011	W3414 CSH VIR Galloping Mit	1	0	0	0	0	0	8/31/2020
Reliability Requirement	NSPW USDA F S Ottawa 17 21	A.0000879.002	NSPW USDA F S Ottawa MI 22 26 ROW	0	0	0	0	80	58	1/15/2022
Reliability Requirement	NSPW Land Sales	A.0000933.004	Nelson Substation Land Sale	1	0	0	0	0	0	12/31/2020
Reliability Requirement	Twin Town Area Upgrades	A.0001159.001	Turtle Lake - Almena ROW	260	190	26	19	0	0	1/15/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.002	Turtle Lake - Almena Line	0	0	4,844	3,537	0	0	1/15/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.003	Turtle Lake Cap Bank Addition	0	0	1,702	1,243	0	0	1/15/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.004	Turtle Lake Comm	0	0	184	135	0	0	1/15/2021
Reliability Requirement	Hurley - Norrie 115kV	A.0001169.001	Hurley - Norrie 115kV	0	0	1,938	1,415	0	0	12/1/2021
Reliability Requirement	Hurley - Norrie 115kV	A.0001169.002	Hur NRR 115kV MI 1.2 Miles	0	0	1,385	1,011	0	0	12/1/2021
Reliability Requirement	Hurley - Norrie 115kV	A.0001169.003	NRR 115kV Yard Improvements	0	0	1,278	933	29	21	12/1/2021
Reliability Requirement	Hurley - Norrie 115kV	A.0001169.004	HUR 115kV Yard Improvements	0	0	3,881	2,834	135	99	12/1/2021
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.001	Clear Lake Area Sub Comm	102	75	0	0	0	0	11/15/2020
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.002	Clear Lake Area Sub Tam	3,539	2,585	0	0	0	0	11/15/2020
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.003	W3427 Reterm 69kV to Ridgeland	431	315	0	0	0	0	11/15/2020
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.004	W3428 Reterm 69kV to Blackbrook	413	301	0	0	0	0	11/15/2020
Reliability Requirement	Clear Lake Area Sub DCP	A.0001186.005	W3429 Reterm 69kV to Lake Camelia	584	427	0	0	0	0	11/15/2020
Reliability Requirement	Bayfront to Ironwood Bad River Res ROW	A.0001193.001	W3351 Bad River Res ROW	3,147	2,298	0	0	0	0	7/1/2020
Reliability Requirement	Rest Lake-Presque Isle	A.0001198.001	Rest Lake Presque Isle ROW	60	44	556	406	360	263	10/15/2023
Reliability Requirement	Copperwood Mine	A.0001266.001	Copperwood Sub - New Sub	0	0	0	0	3,127	2,283	12/15/2022
Reliability Requirement	Copperwood Mine	A.0001266.002	Norrie Sub Termination Sub	0	0	0	0	847	619	12/15/2022
Reliability Requirement	Copperwood Mine	A.0001266.004	W33XX NRR - COP ROW	0	0	0	0	1,900	1,387	12/15/2022
Reliability Requirement	Copperwood Mine	A.0001266.005	Copperwood Mine Eng Svc Agrment	3	2	0	0	0	0	6/1/2020
Reliability Requirement	DCP Elmwood Substation	A.0010163.003	Elmwood Substation 69kV Sub	2,917	2,130	0	0	0	0	12/15/2020
Reliability Requirement	DCP Elmwood Substation	A.0010163.004	W3466 In Out at ELM Sub	33	24	0	0	0	0	12/15/2020
Reliability Requirement	DCP Elmwood Substation	A.0010163.005	W3415 Reterm to ELM Sub	378	276	0	0	0	0	12/15/2020
Reliability Requirement	DCP Elmwood Substation	A.0010163.006	W3466 MEN to ELM Sub	111	81	0	0	0	0	12/15/2020
Reliability Requirement	DCP Elmwood Substation	A.0010163.007	W3466 RLM to ELM Sub	116	84	0	0	0	0	12/15/2020
Reliability Requirement	DCP Ironwood Substation	A.0010164.003	PKR 115 12.5kV SUB DCP	654	477	0	0	0	0	10/15/2020
Reliability Requirement	DCP Ironwood Substation	A.0010164.004	W3325 In Out at PKR SUB DCP	425	310	0	0	0	0	10/15/2020
Reliability Requirement	New North Menomonie Sub	A.0010170.001	W3404 WKD Sub Term	459	335	0	0	0	0	6/1/2020
Reliability Requirement	New North Menomonie Sub	A.0010170.002	WKD New Sub DCP	535	390	0	0	0	0	6/1/2020

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2020		2021		2022		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Reliability Requirement	Hydro Lane Expansion	A.0010171.001	HYD ADD 69 12 5kV 28MVA TAM	934	682	0	0	0	0	5/15/2020
Reliability Requirement	Hydro Lane Expansion	A.0010171.004	Wis REL Upgrade for HYD	87	63	0	0	0	0	5/15/2020
Reliability Requirement	Hydro Lane Expansion	A.0010171.005	Wis REL Upgrade for HYD Comm	49	36	0	0	0	0	5/15/2020
Reliability Requirement	Wissota Beach Sub Rebuild	A.0010173.001	W3491 Reterm to WIB Sub	65	47	0	0	0	0	5/15/2020
Reliability Requirement	Wissota Beach Sub Rebuild	A.0010173.006	BMN New 69 23 9kV Sub DCP	536	391	0	0	0	0	5/15/2020
Reliability Requirement Total				**23,138**	**16,896**	**22,840**	**16,678**	**52,192**	**38,111**	
Asset Renewal	Eau Claire Breakers	A.0000232.003	Eau Claire 345kV Breaker Sub	49	36	0	0	0	0	3/15/2020
Asset Renewal	ELR - Breakers - NSPW	A.0000397.010	NSPW 2016 ELR Breakers Sub	0	0	4,687	3,422	1,794	1,310	12/31/2024
Asset Renewal	ELR - Breakers - NSPW	A.0000397.021	Ironwood-Repalce Bkr 3R17	210	153	0	0	0	0	12/15/2020
Asset Renewal	ELR - Breakers - NSPW	A.0000397.023	Lacrosse-Replace Bkrs 4L44,4L45	0	0	603	440	0	0	12/15/2021
Asset Renewal	ELR - Breakers - NSPW	A.0000397.024	Lacrosse-Replace Bkrs 6L4,6L5,6L7	1,379	1,007	0	0	0	0	12/15/2020
Asset Renewal	ELR - Breakers - NSPW	A.0000397.027	Marshland-Replace Bkrs	0	0	2,187	1,597	0	0	1/31/2021
Asset Renewal	ELR - Breakers - NSPW	A.0000397.029	Prentice-Replace Bkr 4R6	0	0	323	236	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.002	NSPW 2016 ELR Relays, Sub	0	0	2,159	1,576	2,029	1,482	12/31/2024
Asset Renewal	ELR - Relay - NSPW	A.0000503.023	Cedar Falls-Relaying CLL,ECL,MEN,RC	0	0	1,209	883	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.024	Cotton School-Relaying ALC,SPL,SEV,	0	0	1,199	875	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.026	Holcombe-Relaying COR-JIM	320	234	0	0	0	0	12/15/2020
Asset Renewal	ELR - Relay - NSPW	A.0000503.029	Jim Falls-Relaying RCL,HYD,HLC	0	0	1,019	744	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.033	Seven Mile-Relaying ECL,ELS,LON,CTS	1,508	1,101	0	0	0	0	12/15/2020
Asset Renewal	ELR - Relay - NSPW	A.0000503.035	Spokesville-Relaying CTS,TCN,TCN	887	648	0	0	0	0	12/15/2020
Asset Renewal	ELR - Relay - NSPW	A.0000503.036	T-Corners-Relaying SPE,WIT,MFD,SPL	0	0	1,201	877	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.037	Tremval-Relaying ALC,IDP,MLE	0	0	900	657	0	0	12/15/2021
Asset Renewal	ELR - Transformers - NSPW	A.0000398.002	NSPW 2016 ELR Transformers, Su	2,943	2,149	1,518	1,108	1,521	1,111	12/15/2024
Asset Renewal	Line ELR - NSPW	A.0000327.017	NSPW 69kV Line ELR 2016	0	0	8,807	6,431	2,265	1,654	12/15/2024
Asset Renewal	Line ELR - NSPW	A.0000327.022	MI 34.5kV Tline ELR 2016 Line	0	0	149	109	50	37	12/15/2024
Asset Renewal	NSPW Group 1 Switch Replacements	A.0000444.005	NSPW 2016 Switch Rplmts Line	1,152	841	1,476	1,078	1,083	791	12/31/2024
Asset Renewal	NSPW Group 1 Switch Replacements	A.0000444.042	W3430 Luck Sub	20	15	0	0	0	0	12/15/2019
Asset Renewal	NSPW Group 1 Switch Replacements	A.0000444.045	W3408 Naples Replace SW	0	0	0	0	0	0	2/15/2020
Asset Renewal	NSPW Group 1 Switch Replacements	A.0000444.049	W3413 Cochrane Repl SW	5	3	0	0	0	0	3/15/2020
Asset Renewal	NSPW Group 1 Switch Replacements	A.0000444.050	W3405 Elk Mound Replace SW	266	194	0	0	0	0	2/15/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.001	W3432 LaCrosse to Coulee rebui	0	0	4,271	3,119	0	0	12/15/2021
Asset Renewal	NSPW Major Line Rebuild	A.0000689.004	NSPW Major Line RebuildLi	0	0	18,142	13,247	4,906	3,583	12/31/2024
Asset Renewal	NSPW Major Line Rebuild	A.0000689.021	W3477 OGE RBL Tap 69kV Rebuild Line	6,355	4,641	0	0	0	0	2/28/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.022	W3477 RBL STR 368 69kV Rebuild Line	0	0	5,893	4,303	0	0	5/1/2021
Asset Renewal	NSPW Major Line Rebuild	A.0000689.023	W3477 STR MFD 69kV Rebuild Line	0	0	0	0	4,612	3,368	5/1/2022
Asset Renewal	NSPW Major Line Rebuild	A.0000689.024	W3205 LaCrosse Coulee Rebuild	11,519	8,411	0	0	0	0	4/1/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.028	W3321 Lattice Tower Rplmnt 2nd CKT	778	568	0	0	0	0	12/15/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.029	W3323 Lattice Tower Rplmnt Line	2,353	1,718	0	0	0	0	12/15/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.031	W3408 Lufkin to Naples Rebuild	5,005	3,655	0	0	0	0	1/15/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.032	W3630 BES IRW Rbld	994	726	0	0	0	0	1/15/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.033	W3630 BLD IRW	2,981	2,176	0	0	0	0	2/15/2020
Asset Renewal	NSPW Major Line Rebuild	A.0000689.034	W3408 Mondovi to GMN Tap	0	0	3,763	2,748	0	0	9/15/2021
Asset Renewal	NSPW Major Line Rebuild	A.0000689.035	W3408 GMN Tap to STR 563	0	0	0	0	5,499	4,016	9/15/2022
Asset Renewal	NSPW Major Line Rebuild	A.0000689.037	W3405 STR 180 to 269 Rebuild Line	2,135	1,559	0	0	0	0	4/15/2020

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2020		2021		2022		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Asset Renewal	NSPW Major Line Rebuild	A.0000689.039	W3408 Naples to Mondovi	0	0	1,654	1,208	0	0	12/15/2021
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.003	NSPW 2016 Major Line Refurbish	0	0	10,593	7,735	6,053	4,420	12/31/2024
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.037	W3321 Refurb STR 2 to STR 400	1,082	790	0	0	0	0	2/15/2020
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.047	NSW3454 Refurbishment Str 98 to 118	2,243	1,638	0	0	0	0	4/30/2020
Asset Renewal	NSPW Reloc B	A.0000496.022	MI Reloc B 34.5kV Line	50	37	50	37	50	37	12/15/2024
Asset Renewal	NSPW Reloc B	A.0000496.024	NSPW 2016 Reloc B 69Kv Line	384	280	384	281	384	281	12/15/2024
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.003	NSPW - 2016 - ELR - RTUComm	0	0	985	719	981	717	12/31/2024
Asset Renewal	S&E - NSPW Line	A.0000495.021	NSPW 2016 S&E 69kV Line	4,755	3,472	4,956	3,619	2,954	2,157	12/31/2024
Asset Renewal	S&E - NSPW Line	A.0000495.024	MI 2016 S&E 34.5kV Line	50	37	50	37	50	37	12/15/2024
Asset Renewal	S&E - NSPW Line	A.0000495.026	NSPW Priority Defects 69kV Line	551	402	551	402	551	402	12/15/2024
Asset Renewal	S&E - NSPW Sub	A.0000075.008	MI 2016 S&E Sub	49	36	49	36	49	36	12/31/2024
Asset Renewal	S&E - NSPW Sub	A.0000075.009	NSPW 2016 S&E Sub	1,177	860	1,177	860	1,178	860	12/31/2024
Asset Renewal	Tools and Equipment	A.0006059.430	Tool Blanket WI Line	70	51	70	51	70	51	12/31/2023
Asset Renewal	Tools and Equipment	A.0006059.431	NSPW COM Tool	328	240	385	281	400	292	12/31/2024
Asset Renewal	Tools STAC	A.0001019.004	NSPW STAC Tools	12	9	12	9	12	9	12/31/2024
Asset Renewal	Transmission UAV Flights	A.0000855.002	NSPW Transmission UAV	0	0	3,907	2,853	0	0	10/15/2021
Asset Renewal	Unserviceable - Relays - NSPW	A.0000396.003	WI 2016 - Unserviceable Relay	492	359	493	360	493	360	12/31/2024
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.014	Unserviceable Brkr Rep MI	468	341	468	342	468	342	12/31/2024
Asset Renewal	W3203 Briggs LaCrosse Upgrade	A.0002030.001	W3203 Briggs Lacrosse Rbld Lin	0	0	0	0	6,870	5,017	10/31/2022
Asset Renewal Total				**52,570**	**38,387**	**85,289**	**62,280**	**44,323**	**32,366**	
Communication Infrastructure	AGIS Fault Location Service (FLISR)	D.0001902.026	AGIS FLISR NSPW Transmission Precon	0	0	0	0	256	187	12/31/2022
Communication Infrastructure	AGIS Integrated Volt Var (IVVO)	D.0001904.027	AGIS IVVO NSPW Trans Precon	0	0	863	630	0	0	12/31/2021
Communication Infrastructure	Comm Network Program	A.0001320.011	NSPW Comm Network Program Sub	0	0	4,906	3,583	4,906	3,583	12/15/2024
Communication Infrastructure	NSPW COMM Circuit Upgrades	A.0000487.001	NSPW 2017 COMM Circuit Upgrades	170	124	170	124	171	125	12/31/2023
Communications Infrastructure Total				**170**	**124**	**5,939**	**4,337**	**5,333**	**3,895**	
Interconnection	DPC Arkansaw Tap Interconnection	A.0001177.001	W3415 Tap to DPC at Arkansaw Sub	470	343	0	0	0	0	6/30/2020
Interconnection	DPC Switch Interconnections	A.0000873.008	DPC W3408 Interconnection	242	177	0	0	0	0	3/15/2020
Interconnection	DPC Switch Interconnections	A.0000873.009	W3408 DPC N-5 Tie Nelson	394	288	0	0	0	0	9/15/2020
Interconnection	DPC Switch Interconnections	A.0000873.010	W3427 DPC N-4 Tie Clear Lake	380	277	0	0	0	0	12/31/2020
Interconnection	IA Tariff Fund	A.0000076.003	IA Tariff Fund NSPW	991	723	3,069	2,241	5,121	3,740	12/31/2024
Interconnection	W3703 LCO Hydro Tap	A.0000643.002	W3703 23kV Transformer Addition	7	5	0	0	0	0	12/15/2019
Interconnection Total				**2,483**	**1,813**	**3,069**	**2,241**	**5,121**	**3,740**	
Regional Expansion	La Crosse - Madison	A.0000306.002	LAX-MAD New 345kV Non Shared L	89	65	0	0	0	0	12/31/2018
Regional Expansion	La Crosse - Madison	A.0000306.008	3104 Lax-Mad 345 N/S ROW	489	357	0	0	0	0	12/31/2019
Regional Expansion	DCP Kinnickinnic	A.0001247.001	W3426 Reterm at Kin DCP	50	36	0	0	0	0	12/15/2020
Regional Expansion	DCP Kinnickinnic	A.0001247.002	Kin Rbld 69 23 9kV Sub TAM DCP	345	252	0	0	0	0	12/15/2020
Regional Expansion Total				**972**	**710**	**0**	**0**	**0**	**0**	
Physical Security and Resiliency	Physical Security	A.0000710.002	NSPW Physical Security Sub Infrastr	759	554	3,677	2,685	612	447	5/30/2022
Physical Security and Resiliency	Physical Security	A.0000710.006	NSPW Physical Security Comm	276	201	268	195	152	111	11/25/2023
Physical Security and Resiliency	NSPW Geomagnetic Disturbances (GMD)	A.0000766.005	NSPW Geo Mag Dist (GMD)	0	0	0	0	501	366	12/31/2022
Physical Security and Resiliency	NSPW Electro Mag Pulse (EMP)	A.0000775.005	NSPW Electro Mag Pulse (EMP)	0	0	0	0	159	116	12/31/2022
Physical Security and Resiliency Total				**1,034**	**755**	**3,945**	**2,880**	**1,423**	**1,039**	
NSPM Total				**80,368**	**58,686**	**121,082**	**88,416**	**108,393**	**79,150**	

Transmission O&M Budget by Category NSPM-Electric (Dollars in Millions)								
Cost Category	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2016 – 2018 Average**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
Internal Labor	$23.50	$21.40	$22.00	$22.30	$22.10	$22.50	$23.00	$23.60
Contract Labor and Consulting	$6.80	$4.70	$4.50	$5.30	$4.20	$3.70	$3.70	$3.80
Employee Expenses	$2.40	$2.70	$2.90	$2.70	$2.60	$2.80	$2.80	$2.90
Fees	$3.70	$3.50	$3.50	$3.60	$3.60	$3.70	$4.10	$4.30
Materials	$3.00	$3.60	$3.30	$3.30	$2.80	$3.20	$2.60	$2.70
Other	$3.80	$5.10	$4.10	$4.30	$1.00	$3.30	$1.70	$0.80
Total	**$43.20**	**$41.00**	**$40.30**	**$41.50**	**$36.30**	**$39.20**	**$37.90**	**$38.10**

NSP System Transmission Expenses ($000's)

Description	2018 ACTUALS (000's)	2020 BUDGET (000's)	2021 BUDGET (000's)	2022 BUDGET (000's)
NSP JPZ payments and GRE JPZ charges	$ 58,636	$ 55,412	$ 59,439	$ 60,608
MISO Network Service	$ 10,312	$ 10,986	$ 11,208	$ 11,564
MISO Transmission Expansion Plan (RECB)	$ 126,909	$ 124,871	$ 123,515	$ 124,493
Schedule 2 (Reactive Supply)	$ 9,942	$ 10,393	$ 10,301	$ 10,319
MISO Schedules 10, 10-FERC	$ 11,936	$ 11,047	$ 11,153	$ 11,817
MISO Schedules 16 and 17	$ 8,880	$ 8,923	$ 8,859	$ 8,872
MISO Schedule 24	$ 1,273	$ 1,269	$ 1,307	$ 1,347
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 205	$ 242	$ 247	$ 255
Sch 33 - Blackstart	$ 30	$ 31	$ 32	$ 33
Sch 45 - NREAC Recovery	$ 1	$ 2	$ 2	$ 2
Other native load deliveries	$ 71	$ 69	$ 69	$ 69
SPP Point-to-Point	$ 80	$ 79	$ 81	$ 83
MISO Point-to-Point	$ 75	$ 84	$ 87	$ 89
MISO System Studies	$ 20	$ 30	$ 31	$ 32
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ 1,708	$ 1,708	$ 1,708	$ 1,708
Total Expense	**$ 230,079**	**$ 225,147**	**$ 228,039**	**$ 231,289**
Less:				
MISO Schedules 10, 10-FERC - Regional Markets portion	$ 262	$ 234	$ 235	$ 253
MISO Schedules 16 and 17	$ 8,880	$ 8,923	$ 8,859	$ 8,872
MISO Schedule 24	$ 1,273	$ 1,269	$ 1,307	$ 1,347
Note: Regional Markets Items [See Note #1]	**$ 10,414**	**$ 10,426**	**$ 10,402**	**$ 10,471**
MISO Transmission Expansion Plan (RECB)	$ 126,909	$ 124,871	$ 123,515	$ 124,493
Note: Items Collected through TCR	**$ 126,909**	**$ 124,871**	**$ 123,515**	**$ 124,493**
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ 1,708	$ 1,708	$ 1,708	$ 1,708
Note: Items Collected through RES	**$ 1,708**	**$ 1,708**	**$ 1,708**	**$ 1,708**
Net Base Rate Transmission Expense	**$ 91,047**	**$ 88,141**	**$ 92,413**	**$ 94,617**

Note #1
MISO energy and ancillary services market administration charges are reflected in Commercial Operations portion of Energy Supply budget and included in base rates.

NSP System Transmission Revenues ($000's)

Description	2018 ACTUALS (000's)	2020 BUDGET (000's)	2021 BUDGET (000's)	2022 BUDGET (000's)
Network JPZ - GRE/SMMPA	$ 49,926	$ 48,861	$ 54,356	$ 55,913
Network Service - Midwest ISO Tariff	$ 26,017	$ 30,863	$ 28,052	$ 28,894
MISO Transmission Expansion Plan (RECB)	$ 127,242	$ 132,850	$ 132,208	$ 138,817
Point-to-Point Firm, Point-to-Point Non Firm	$ 8,054	$ 7,334	$ 7,341	$ 7,349
Schedule 2 (Reactive Supply)	$ 9,253	$ 10,524	$ 10,524	$ 10,524
Tm-1 GFAs	$ -	$ -	$ -	$ -
Fixed GFA Contracts	$ 407	$ 414	$ 417	$ 420
MISO Schedule 24 - Balancing Authority	$ 1,118	$ 1,151	$ 1,183	$ 1,218
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 920	$ 727	$ 727	$ 727
GRE O&M service	$ 235	$ 222	$ 222	$ 222
Marshall TOPS Agreement	$ 134	$ 140	$ 144	$ 148
Total Revenue Collected	**$ 223,307**	**$ 233,085**	**$ 235,173**	**$ 244,230**
Less:				
Schedule 2 (Reactive Supply)	$ 9,253	$ 10,524	$ 10,524	$ 10,524
Note: Revenues transfer to Energy Supply	**$ 9,253**	**$ 10,524**	**$ 10,524**	**$ 10,524**
MISO Transmission Expansion Plan (RECB)	$ 127,242	$ 132,850	$ 132,208	$ 138,817
Note: Included as credit in TCR Rider	**$ 127,242**	**$ 132,850**	**$ 132,208**	**$ 138,817**
GRE O&M service	$ 235	$ 222	$ 222	$ 222
Marshall TOPS Agreement	$ 134	$ 140	$ 144	$ 148
Note: Revenues transfer to Distribution	**$ 369**	**$ 362**	**$ 365**	**$ 369**
Net Base Rate Transmisison Revenue	**$ 86,443**	**$ 89,350**	**$ 92,076**	**$ 94,521**

Joint Zonal Revenues and Expenses - 2020 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-20	$ 2,733,043	$ 442,545	$ 435,648	$ 3,611,236
Feb-20	$ 2,456,787	$ 398,670	$ 396,067	$ 3,251,524
Mar-20	$ 2,450,275	$ 411,024	$ 411,265	$ 3,272,564
Apr-20	$ 2,065,081	$ 390,857	$ 376,352	$ 2,832,291
May-20	$ 2,796,303	$ 506,738	$ 406,696	$ 3,709,737
Jun-20	$ 3,087,874	$ 554,079	$ 427,305	$ 4,069,257
Jul-20	$ 3,597,249	$ 611,040	$ 469,122	$ 4,677,411
Aug-20	$ 3,352,807	$ 591,410	$ 457,628	$ 4,401,845
Sep-20	$ 2,867,606	$ 531,957	$ 406,769	$ 3,806,333
Oct-20	$ 2,058,559	$ 442,434	$ 379,827	$ 2,880,820
Nov-20	$ 2,385,703	$ 405,237	$ 385,815	$ 3,176,755
Dec-20	$ 2,732,624	$ 438,889	$ 421,749	$ 3,593,262
Total	**$ 32,583,909**	**$ 5,724,881**	**$ 4,974,243**	**$ 43,283,034**

GRE JPZ	GRE
Jan-20	$ 491,780
Feb-20	$ 449,238
Mar-20	$ 448,945
Apr-20	$ 368,826
May-20	$ 372,183
Jun-20	$ 536,834
Jul-20	$ 593,017
Aug-20	$ 564,083
Sep-20	$ 499,860
Oct-20	$ 368,982
Nov-20	$ 415,353
Dec-20	$ 468,415
Total	**$ 5,577,516**

Total GRE Revenue $ 38,161,425.50

Total Transmission Joint Zonal Revenue **$48,860,550**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-20	$ 2,446,485	$ 1,071,114	$ 103,119	$ 43,871	$ 95,789	$ 139,659	$ 168,410	$ 4,068,447
Feb-20	$ 2,222,296	$ 959,758	$ 92,399	$ 39,310	$ 85,830	$ 125,140	$ 150,902	$ 3,675,634
Mar-20	$ 2,271,947	$ 984,420	$ 94,773	$ 40,320	$ 88,036	$ 128,356	$ 154,779	$ 3,762,630
Apr-20	$ 2,039,142	$ 868,784	$ 83,641	$ 35,584	$ 77,694	$ 113,278	$ 136,598	$ 3,354,720
May-20	$ 2,524,338	$ 1,109,784	$ 106,842	$ 45,455	$ 99,247	$ 144,702	$ 174,490	$ 4,204,858
Jun-20	$ 3,043,666	$ 1,367,738	$ 131,676	$ 56,020	$ 122,315	$ 178,335	$ 215,048	$ 5,114,799
Jul-20	$ 3,354,370	$ 1,522,067	$ 146,534	$ 62,341	$ 136,117	$ 198,458	$ 239,313	$ 5,659,200
Aug-20	$ 3,202,980	$ 1,446,870	$ 139,295	$ 59,261	$ 129,392	$ 188,653	$ 227,490	$ 5,393,941
Sep-20	$ 2,744,660	$ 1,219,219	$ 117,378	$ 49,937	$ 109,033	$ 158,970	$ 191,697	$ 4,590,895
Oct-20	$ 2,201,346	$ 949,352	$ 91,397	$ 38,884	$ 84,900	$ 123,783	$ 149,266	$ 3,638,927
Nov-20	$ 2,189,919	$ 943,676	$ 90,851	$ 38,651	$ 84,392	$ 123,043	$ 148,373	$ 3,618,905
Dec-20	$ 2,449,564	$ 1,072,643	$ 103,267	$ 43,934	$ 95,925	$ 139,859	$ 168,651	$ 4,073,843
Total	**$ 30,690,712**	**$ 13,515,424**	**$ 1,301,172**	**$ 553,567**	**$ 1,208,670**	**$ 1,762,237**	**$ 2,125,019**	**$ 51,156,801**

GRE JPZ	GRE
Jan-20	$ 349,953
Feb-20	$ 297,259
Mar-20	$ 398,337
Apr-20	$ 297,703
May-20	$ 263,324
Jun-20	$ 328,722
Jul-20	$ 519,317
Aug-20	$ 404,269
Sep-20	$ 283,343
Oct-20	$ 322,977
Nov-20	$ 368,485
Dec-20	$ 421,981
Total	**$ 4,255,671**

Total GRE Expense $ 34,946,383.55

Total Transmission Joint Zonal Expense **$ 55,412,472**

Net Transmission Joint Zonal **($6,551,923)**

Net Transmission Joint Zonal Payment for NSP Pricing Zone	**$ (7,873,768)**
Net Transmission Joint Zonal Payment for GRE Pricing Zone	**$ 1,321,845**

Joint Zonal Revenues and Expenses - 2021 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-21	$ 3,077,468	$ 498,316	$ 490,550	$ 4,066,333
Feb-21	$ 2,671,004	$ 433,432	$ 430,601	$ 3,535,038
Mar-21	$ 2,759,064	$ 462,822	$ 463,094	$ 3,684,980
Apr-21	$ 2,325,328	$ 440,114	$ 423,781	$ 3,189,223
May-21	$ 3,148,700	$ 570,599	$ 457,949	$ 4,177,248
Jun-21	$ 3,477,015	$ 623,905	$ 481,155	$ 4,582,075
Jul-21	$ 4,050,584	$ 688,044	$ 528,242	$ 5,266,870
Aug-21	$ 3,775,336	$ 665,941	$ 515,299	$ 4,956,577
Sep-21	$ 3,228,989	$ 598,996	$ 458,031	$ 4,286,016
Oct-21	$ 2,317,984	$ 498,190	$ 427,694	$ 3,243,868
Nov-21	$ 2,686,355	$ 456,306	$ 434,437	$ 3,577,098
Dec-21	$ 3,076,996	$ 494,199	$ 474,899	$ 4,046,094
Total	**$ 36,594,824**	**$ 6,430,865**	**$ 5,585,732**	**$ 48,611,421**

GRE JPZ	GRE
Jan-21	$ 506,533
Feb-21	$ 462,715
Mar-21	$ 462,414
Apr-21	$ 379,891
May-21	$ 383,349
Jun-21	$ 552,939
Jul-21	$ 610,807
Aug-21	$ 581,006
Sep-21	$ 514,856
Oct-21	$ 380,052
Nov-21	$ 427,814
Dec-21	$ 482,467
Total	**$ 5,744,842**
Total GRE Revenue	**$ 42,339,665.53**

Total Transmission Joint Zonal Revenue $54,356,263

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-21	$ 2,733,294	$ 1,074,054	$ 103,410	$ 43,982	$ 96,058	$ 140,041	$ 168,868	$ 4,359,708
Feb-21	$ 2,364,680	$ 929,207	$ 89,464	$ 38,051	$ 83,104	$ 121,155	$ 146,094	$ 3,771,754
Mar-21	$ 2,512,066	$ 987,122	$ 95,040	$ 40,423	$ 88,284	$ 128,706	$ 155,200	$ 4,006,840
Apr-21	$ 2,216,983	$ 871,169	$ 83,876	$ 35,674	$ 77,913	$ 113,588	$ 136,969	$ 3,536,173
May-21	$ 2,831,974	$ 1,112,831	$ 107,144	$ 45,570	$ 99,526	$ 145,097	$ 174,965	$ 4,517,106
Jun-21	$ 3,490,226	$ 1,371,493	$ 132,048	$ 56,162	$ 122,660	$ 178,822	$ 215,633	$ 5,567,043
Jul-21	$ 3,884,046	$ 1,526,245	$ 146,947	$ 62,500	$ 136,500	$ 199,000	$ 239,964	$ 6,195,202
Aug-21	$ 3,692,158	$ 1,450,842	$ 139,687	$ 59,412	$ 129,756	$ 189,168	$ 228,108	$ 5,889,132
Sep-21	$ 3,111,233	$ 1,222,566	$ 117,709	$ 50,064	$ 109,341	$ 159,405	$ 192,218	$ 4,962,535
Oct-21	$ 2,422,579	$ 951,958	$ 91,655	$ 38,983	$ 85,139	$ 124,121	$ 149,671	$ 3,864,106
Nov-21	$ 2,408,095	$ 946,267	$ 91,107	$ 38,750	$ 84,630	$ 123,379	$ 148,777	$ 3,841,003
Dec-21	$ 2,737,197	$ 1,075,588	$ 103,558	$ 44,045	$ 96,196	$ 140,241	$ 169,109	$ 4,365,934
Total	**$ 34,404,530**	**$ 13,519,342**	**$ 1,301,646**	**$ 553,616**	**$ 1,209,106**	**$ 1,762,722**	**$ 2,125,575**	**$ 54,876,537**

GRE JPZ	GRE
Jan-21	$ 383,315
Feb-21	$ 383,315
Mar-21	$ 370,950
Apr-21	$ 370,950
May-21	$ 383,315
Jun-21	$ 383,315
Jul-21	$ 383,315
Aug-21	$ 383,315
Sep-21	$ 383,315
Oct-21	$ 383,315
Nov-21	$ 370,950
Dec-21	$ 383,315
Total	**$ 4,562,689**
Total GRE Expense	**$ 38,967,219.81**

Total Transmission Joint Zonal Expense	$ 59,439,226
Net Transmission Joint Zonal	($5,082,964)
Net Transmission Joint Zonal Payment for NSP Pricing Zone	$ (6,265,116)
Net Transmission Joint Zonal Payment for GRE Pricing Zone	$ 1,182,152

Joint Zonal Revenues and Expenses - 2022 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-22	$ 3,165,135	$ 512,511	$ 504,524	$ 4,182,170
Feb-22	$ 2,747,093	$ 445,779	$ 442,868	$ 3,635,740
Mar-22	$ 2,837,661	$ 476,007	$ 476,286	$ 3,789,954
Apr-22	$ 2,391,570	$ 452,652	$ 435,853	$ 3,280,074
May-22	$ 3,238,396	$ 586,853	$ 470,995	$ 4,296,244
Jun-22	$ 3,576,065	$ 641,678	$ 494,861	$ 4,712,604
Jul-22	$ 4,165,972	$ 707,644	$ 543,290	$ 5,416,906
Aug-22	$ 3,882,883	$ 684,912	$ 529,979	$ 5,097,774
Sep-22	$ 3,320,973	$ 616,060	$ 471,079	$ 4,408,111
Oct-22	$ 2,384,016	$ 512,382	$ 439,878	$ 3,336,276
Nov-22	$ 2,762,881	$ 469,305	$ 446,812	$ 3,678,998
Dec-22	$ 3,164,650	$ 508,278	$ 488,427	$ 4,161,355
Total	**$ 37,637,294**	**$ 6,614,060**	**$ 5,744,851**	**$ 49,996,206**

GRE JPZ	GRE
Jan-22	$ 521,729
Feb-22	$ 476,596
Mar-22	$ 476,286
Apr-22	$ 391,288
May-22	$ 394,849
Jun-22	$ 569,527
Jul-22	$ 629,131
Aug-22	$ 598,436
Sep-22	$ 530,301
Oct-22	$ 391,453
Nov-22	$ 440,648
Dec-22	$ 496,941
Total	**$ 5,917,187**

Total GRE Revenue **$ 43,554,481.11**

Total Transmission Joint Zonal Revenue **$55,913,393**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-22	$ 2,815,269	$ 1,074,041	$ 103,405	$ 43,975	$ 96,042	$ 140,050	$ 168,870	$ 4,441,652
Feb-22	$ 2,435,600	$ 929,195	$ 89,459	$ 38,045	$ 83,090	$ 121,163	$ 146,096	$ 3,842,647
Mar-22	$ 2,587,406	$ 987,110	$ 95,035	$ 40,416	$ 88,269	$ 128,715	$ 155,202	$ 4,082,152
Apr-22	$ 2,283,474	$ 871,158	$ 83,872	$ 35,668	$ 77,900	$ 113,595	$ 136,971	$ 3,602,638
May-22	$ 2,916,908	$ 1,112,816	$ 107,138	$ 45,563	$ 99,510	$ 145,107	$ 174,966	$ 4,602,008
Jun-22	$ 3,594,902	$ 1,371,475	$ 132,040	$ 56,153	$ 122,639	$ 178,835	$ 215,635	$ 5,671,680
Jul-22	$ 4,000,534	$ 1,526,226	$ 146,939	$ 62,489	$ 136,477	$ 199,013	$ 239,966	$ 6,311,645
Aug-22	$ 3,802,890	$ 1,450,824	$ 139,680	$ 59,402	$ 129,735	$ 189,181	$ 228,111	$ 5,999,822
Sep-22	$ 3,204,543	$ 1,222,551	$ 117,703	$ 50,056	$ 109,322	$ 159,416	$ 192,220	$ 5,055,809
Oct-22	$ 2,495,235	$ 951,946	$ 91,650	$ 38,976	$ 85,124	$ 124,130	$ 149,673	$ 3,936,734
Nov-22	$ 2,480,317	$ 946,255	$ 91,102	$ 38,743	$ 84,615	$ 123,388	$ 148,778	$ 3,913,197
Dec-22	$ 2,819,290	$ 1,075,574	$ 103,552	$ 44,038	$ 96,179	$ 140,250	$ 169,111	$ 4,447,995
Total	**$ 35,436,369**	**$ 13,519,169**	**$ 1,301,574**	**$ 553,524**	**$ 1,208,902**	**$ 1,762,844**	**$ 2,125,598**	**$ 55,907,978**

GRE JPZ	GRE
Jan-22	$ 394,815
Feb-22	$ 394,815
Mar-22	$ 382,079
Apr-22	$ 382,079
May-22	$ 394,815
Jun-22	$ 394,815
Jul-22	$ 394,815
Aug-22	$ 394,815
Sep-22	$ 394,815
Oct-22	$ 394,815
Nov-22	$ 382,079
Dec-22	$ 394,815
Total	**$ 4,699,570**

Total GRE Expense **$ 40,135,938.71**

Total Transmission Joint Zonal Expense	**$ 60,607,548**
Net Transmission Joint Zonal	**($4,694,156)**
Net Transmission Joint Zonal Payment for NSP Pricing Zone	**$ (5,911,772)**
Net Transmission Joint Zonal Payment for GRE Pricing Zone	**$ 1,217,617**