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Direct Testimony and Schedules
Kelly A. Bloch

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-21-630
Exhibit___(KAB-1)

Distribution

October 25, 2021

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kelly A. Bloch. I am the Regional Vice President, Distribution Operations for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 30 years of experience in the utility industry. I joined Public Service Company of Colorado, another operating company of Xcel Energy, in 1991 and have served in various engineering roles since that time. In my current role, I am responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of Minnesota, North Dakota, South Dakota, Michigan, and Wisconsin. My resume is attached as Exhibit___(KAB-1), Schedule 1.

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

A. I present and support the Company's capital and operations and maintenance (O&M) budgets for the Distribution business area, for purposes of determining electric revenue requirements and final rates in this proceeding. I further discuss the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis, provide information regarding the cost savings achieved from the LED street light conversion project, and discuss methods to measure losses on the distribution system. I also address the Company's Electric Vehicle (EV) programs and the EV capital and O&M expenses that are included in Distribution's budget.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DISTRIBUTION BUSINESS AREA.

A. The Distribution organization is responsible for operating, maintaining, and constructing the distribution system that is the critical final link in delivering electricity to our customers to power their homes and businesses. Given this responsibility, many of Distribution's investments and efforts are focused on maintaining the reliability, resiliency, and health of our existing distribution facilities.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK THAT DISTRIBUTION WILL BE PERFORMING OVER THE TERM OF THIS MULTI-YEAR RATE PLAN (MYRP) (2022-2024)?

A. Our distribution system is the last mile of our electric system and is portion that is closest to our customers. This system consists of overhead feeder lines, poles, and underground cable that connect individual customers to the larger electric grid. The system also includes substations composed of transformers, switches, breakers, and relays that step-down the high voltage power from transmission lines to serve our customers. Each of these assets must be maintained in good working order for our distribution system to be able to work as it is intended. The health of our distribution system is critical to ensuring that we continue to provide reliable electric service today and in the future. To that end, over the term of this multi-year rate plan our investments in our distribution system will be focused on achieving three primary objectives: (1) addressing our aging assets; (2) enabling the clean energy transition; and (3) modernizing the grid. I will discuss these three objectives and the work that Distribution will be doing to achieve them during the term of this multi-year rate plan in greater detail below.

Address Aging Assets

For over 100 years, our Distribution business area has been focused on the delivery of safe and reliable electric service to our customers. Construction of electricity infrastructure in the United States began in the early 1900s and throughout the 1900s this investment was driven by new transmission technologies, central station generating plants, and growing electricity demand, especially after World War II. In the 1950s and 1960s, Xcel Energy expanded its distribution network of overhead feeder lines and added more substations to address this increase in electric demand as well as the growth and expansion of suburban communities. In the 1970s, we continued to see an increase in electrical demand due to the proliferation of central air conditioning in homes and businesses. This resulted in capacity upgrades throughout our system such as installing higher capacity wires, with more phases that were often coupled with replacement of the pole to accommodate these heavier wires. This also included installing higher capacity transformers at our substations. Also during the late 1960s and 1970s, Xcel Energy began to more widely utilize underground construction with underground cables to expand the distribution network to serve new residential and commercial developments. As this history demonstrates, the primary driver of our distribution investments since the 1900s has been addressing the load-serving needs of our customers by adding capacity to meet growing electrical loads and expanding our distribution system to serve new and growing communities. These load-serving investments have often included a number of replacements of aging equipment. For instance, when more capacity was needed at a substation, we replaced a smaller undersized, and aging transformer with a larger transformer with more capacity.

However, as load growth flattened in the early 2000s, fewer pieces of equipment were replaced through capacity driven projects. At the same time, there was also a growing number of assets on our system, which were untouched by prior capacity improvements, that were reaching the end of their useful life. During the early 2000s, Distribution began to make investments to specifically address the age and condition of its facilities. The estimated service life of our equipment varies from approximately 55 years for transformers, 50 years for a distribution pole, and 27-34 years for older generation underground cables. As a result, in the early 2000s, we began to see poles that had been installed in the post-World War II era reach their 50-year service life. Likewise, underground cables installed in the 1960s and 1970s also started to reach their expected useful life.

Since the early 2000s our assets have continued to age, and now many more of these assets are beyond their expected service life. To address the age and condition of these assets, Distribution will be placing greater focus on its Asset Health and Reliability budget category during this multi-year rate plan, to ensure that we continue to meet our long-standing priority of providing safe and reliable service to our customers. The majority of the investments that Distribution will be making during this rate case period will be in established programs in our Asset Health and Reliability budget category including our Pole Replacement and Substation Renewal programs.

Our Pole Replacement program assesses and replaces any pole on our system that has a structure strength of less than 70 percent or that exhibits severe above ground deterioration. Given the buildout of the distribution system that occurred in the 1950s and 1960s, many of the poles on our system are between

50-70 years old and past their estimated useful life of 50 years. In fact, in recent years, we have seen the percentage of poles that have failed annual inspections grow from 4.6 percent in 2010 to 16.4 percent in 2020. To address these aging assets, Distribution will be making increasing investments in this program to replace more of these aging poles per year.

In our substation renewal programs, we are planning to increase investments to replace these key assets closer to their anticipated service life. For instance, there are approximately 104 distribution substation transformers on the NSPM system that are 50 years old or older and another 101 that are between 40-49 years old. Substation transformers have an average service life of 55 years and after that point they experience higher degradation, lower reliability, and increased failure rates. As a transformer failure can result in 5,000 to 15,000 customers losing service, often for an extended period, we need to make the necessary investments to replace those transformers that are beyond their anticipated service life before they fail.

We will also be adding a number of new programs within our Asset Health and Reliability budget category to address specific assets that are, in some cases, having a pronounced impact on reliability. These new programs include the following:

- Pole top reinforcement program;
- Porcelain cutout replacement program;
- Arrestor replacement program, and
- End-of-life recloser program.

For example, our new arrestor replacement program will replace arrestors on our overhead feeder lines that have higher than average failure rates. It is estimated that over 90 percent of the System Average Interruption Duration Index (SAIDI) impact from failed arrestors is from less than 30 percent of the arrestor population. Likewise, our new porcelain cutout replacement program will systematically replace our existing population of 100,000 porcelain cutouts with polymer cutouts that are more reliable and better able to withstand our Minnesota cold temperatures. The existing porcelain cutouts have been experiencing an increasing rate of premature failure in recent years, averaging approximately 750 failures per year.

As we replace these aging assets, we are also looking at ways to harden our system and make it more resilient. In recent years, we have seen more extreme weather events across the country and in the Midwest. To respond to the increase in the frequency and severity of these extreme weather events, we are making sure that the assets that we install are better able to withstand these events. For instance, Distribution has started to install a higher class, larger diameter wood pole as part of its pole replacement program. These larger diameter poles are better able to withstand higher wind speeds and increased ice loadings. During the term of this multi-year rate plan, we will also be transitioning to conduit construction for our mainline cables. This type of construction improves the reliability of our underground system by protecting our underground cables from the elements and wildlife.

These investments are necessary to meet our customers' reliability expectations, which have been further amplified by the COVID-19 pandemic that led to greater acceptance of working from home. While we have been making ongoing investments to maintain the reliability of the system by replacing assets on an as needed basis, we have now reached the point where we need to increase the level of these investments to address a greater number assets that are at or are approaching their estimated service life. Without these needed asset replacements, the system will be at greater risk of outage events due to equipment failures. Xcel Energy is not unique in its need to address its aging distribution infrastructure. An analysis from the U.S. Energy Information Administration reported that spending on electric distribution systems by major U.S. electric utilities has risen 54 percent over the past two decades, from $31 billion to $51 billion annually.[1]

Enabling the Clean Energy Transition

Our investments during this multi-year rate plan are also targeted at enabling the clean energy transition by supporting the interconnection of Distributed Energy Resources (DERs), like rooftop solar, to the system and preparing the grid for greater electrification. In the near term, this electrification will be in the transportation sector as electric vehicle (EV) use becomes more widespread.

Both DERs and greater electrification of the system will require that our distribution equipment be robust enough to maintain proper voltage levels when these new generation resources or load comes online. Our investments in our Asset Health and Reliability category will be essential to enabling our grid to handle these changes. For instance, replacing key assets like substation transformers and breakers better ensure that this equipment is able to handle these different power flows. We are also supporting DERs through other investments like our Community Solar Garden Recloser program in 2022. This

[1] https://www.eia.gov/todayinenergy/detail.php?id=36675.

program will install electronic reclosers on both new and existing Community Solar Gardens to reduce the frequency and impact of planned outages on the generation output of these resources.

Xcel Energy will also be supporting the clean energy transition through investments in a number of existing EV programs as well as expanding our EV offerings. Xcel Energy has committed to working with public, private, and non-profit partners to power 1.5 million EVs across the areas served by Xcel Energy's operating companies by 2030, which is 20 percent of all vehicles and is equivalent to a 30-fold increase in electric vehicles. This increase in EVs will not only save customers fuel costs, but it will also significantly reduce carbon emissions. This includes work on several pilot programs that were previously approved by the Commission, the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot,[2] as well as for four new pilots and programs that are currently before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending before the Commission. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket.

<u>*Modernizing the Grid*</u>

The last area of focus for Distribution during this multi-year rate plan will be implementing a variety of investments as part of the Advanced Grid Intelligence and Security (AGIS) Initiative to modernize the distribution system. These

[2] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

investments will make the grid smarter and more responsive, increase system visibility and control, and to enable expanded customer options. While we have already implemented certain modernization improvements on the distribution system, during this multi-year plan, we will be implementing several major investments to further modernize the grid. For instance, in 2022, we will start deploying Advanced Metering Infrastructure (AMI) meters in mass across our service territory. These AMI meters will provide value to our customers by increasing visibility and information that will allow for greater energy usage insights, reliability improvements, and enhanced rate and demand side management (DSM) offerings. AMI will also provide benefits for the Company by enhancing utility planning and improving operational capabilities. We are also deploying Fault Location, Isolation, and Service Restoration (FLISR) to reduce the duration of customer outages. FLISR works by detecting faults on overhead feeders, isolating the fault, and restoring power to the unfaulted portions of the feeder. These AGIS investments, in concert with future investments, will provide cumulative benefits that will help to modernize the distribution system while also providing an improved customer experience.

The work that Distribution will be doing over the course of this multi-year rate plan will be critical to ensuring that the last mile of our electrical system is able to continue to provide safe and reliable service for our customers as well as supporting the clean energy transition and meeting the demands of the future.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony first describes the workings of the Distribution organization and the services that we provide to our customers. I will identify the key categories of capital investments undertaken by Distribution and describe how the

Distribution business area prepares and manages its capital budget. I explain that we are proposing capital additions of approximately $470.7 million for 2022, $515.2 million for 2023, and $558.9 million for 2024 on a State of Minnesota Electric Jurisdiction basis. Of these amounts $395.1 million in 2022, $416.9 million in 2023, and $452.6 million in 2024 will be recovered in base rates while the remainder relate to certain AGIS-related investments that will be recovered through the Transmission Cost Recovery (TCR) Rider. I provide information on the key capital projects that Distribution will complete over the term of the MYRP organized by our capital budget categories.

I then discuss Distribution's O&M budgets for 2022 to 2024, which are driven by internal and contract labor costs, vegetation management, damage prevention, AGIS, and materials. I also explain why our O&M budgets are reasonable and reflect expenditures that are needed to ensure that our distribution system is safe and reliable.

In addition, I address the Company's EV programs, and discuss the EV capital and O&M expenses included under the Distribution budget for 2022 to 2024.

Further, I provide information regarding the cost and cost savings related to the Light Emitting Diode (LED) street light conversion project. I then provide information supporting the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis. Finally, I report on methods to determine electric losses on the distribution system as required by the Commission's order from our 2015 rate case (Docket No. E002/GR-15-826).

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Distribution Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – Electric Vehicle Programs
- *Section VI* – LED Street Lights
- *Section VII* – Minimum System Study and Zero Intercept Analysis
- *Section VIII* – Distribution System Losses
- *Section IX* – Conclusion

II. DISTRIBUTION OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF NSPM'S DISTRIBUTION SYSTEM.

A. The NSPM distribution system serves approximately 1.5 million electric customers across the NSPM territory, including approximately 1.3 million customers in Minnesota. The distribution system is the final link that allows electricity to safely and reliably reach our customers' homes and businesses. The NSPM distribution system comprises 1,189 feeders, approximately 15,000 circuit miles of overhead conductor on over 600,000 overhead poles and over 11,000 circuit miles of underground cable. This network of feeders connects over 26,000 miles of distribution lines and 242 distribution-level substations in Minnesota.

Q. WHY IS THE DISTRIBUTION BUSINESS UNIT IMPORTANT TO THE COMPANY AND ITS CUSTOMERS?

A. The Distribution business unit is responsible for constructing, operating, maintaining, and repairing the portion of the electric system that directly connects to our customers' homes and businesses. The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. Our work includes performing regular maintenance, repairs, and replacement of poles, wires, underground cables, metering, and transformers, extending service to new customers or increasing the capacity of the system to accommodate new or increased load, and repairing facilities damaged during severe weather to quickly restore service to customers.

Q. PLEASE DESCRIBE THE DISTRIBUTION BUSINESS UNIT'S KEY FUNCTIONS AND SERVICES.

A. The key functions of the Distribution organization include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. There are approximately 1,300 employees (including XES employees) assigned to provide services to the NSPM distribution system. These employees are assigned to one of the five functional areas within Distribution: Distribution Operations, Engineering, Business Operations, AGIS and Metering, and Planning and Performance.

Q. WHAT ARE THE RESPONSIBILITIES OF THESE FOUR FUNCTIONAL AREAS OF DISTRIBUTION?

A. The key responsibilities of these four functional areas include:

- *Operations*. Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response.
- *Engineering*. Provides technical support and system planning, including addressing distribution-related customer service issues.
- *Business Operations*. Responsible for several areas, including vegetation management, outdoor lighting, facility attachments, and the builders call-line.
- *AGIS and Metering*. Responsible for implementing the AGIS initiative and metering.
- *Planning and Performance*. Provides business planning, consulting, analytical services and performance governance and management.

Q. HOW DOES DISTRIBUTION SUPPORT THE FUNCTIONS DESCRIBED ABOVE?

A. Distribution makes capital investments and incurs O&M costs to maintain and improve the reliability of the system, modernize the distribution system, improve functionality, extend service to new customers, and relocate facilities in response to road construction or other governmental projects. I will discuss our capital investments and O&M trends in more detail below.

III. CAPITAL INVESTMENTS

A. Overview of Distribution's Capital Investments

Q. HOW DOES DISTRIBUTION CATEGORIZE THEIR CAPITAL ADDITIONS?

A. Our capital projects fall into eight capital budget groupings, depending on the primary purpose of the project. Distribution has a well-defined process for identifying and determining our investments within these eight capital budget groupings. These groupings are:

Asset Health and Reliability: Projects in this category are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting service reliability and increasing O&M expenditures needed to repair the equipment. When poor performing assets are identified, projects that will improve asset performance are included in the budget. Projects in this category include replacement of underground cable, wood poles, overhead lines, substation equipment including transformers and breakers that have reached the end of their lives. This category also captures replacements due to storms and public damage.

AGIS: Traditionally, our investments to modernize our system were budgeted in the Asset Health and Reliability category. Beginning in 2019, as we launched the AGIS initiative, we separated these investments into their own budget category. The AGIS initiative will improve power reliability, reduce power outages, integrate increasing amounts of DER onto the grid, and empower customers to control and track their energy usage. As I mentioned, the Company will be seeking recovery for the capital costs associated AMI and FAN in the TCR. These investments are discussed here as they are an important part of our overall capital investments during the term of this MYRP.

Electric Vehicle Programs: This category includes the capital costs associated with EV pilots and programs that were previously approved by the Commission – the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription

Service Pilot, and Multi-Dwelling Unit Charging Pilot.[3] Additionally, the Company has budgeted for four new EV programs that are currently pending before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending before the Commission. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket. These EV pilots and programs are discussed in more detail in Section V below.

New Business: This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, and service laterals that bring electrical service from an existing distribution line to a new home or business.

Capacity: This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system, due to new customers or existing customers increasing their load, and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.

Mandates: This category covers projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public works

[3] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

projects such as a road widening or realignment project. These projects generally trend with the availability of municipal and state funding for public works projects. Mandate projects typically result in updated distribution infrastructure.

Tools and Equipment: This category includes tools, communication equipment and various other items that do not fit within the other budget categories. Communication equipment includes the communication components of projects or programs including Feeder Load Monitoring program, Network Monitoring program, Fiber Buildout program, Cyber Security program, and capital associated with locating costs.

Solar: This category includes the distribution costs associated with interconnecting community solar gardens to the distribution system as well as providing service extension to allow electric service for any auxiliary electric needs. The costs for these facilities are billed to the developer at several different increments throughout the development and construction of the solar garden. Once payment is received and the work is completed by Distribution, a credit is applied to this category.

Q. ARE FLEET CAPITAL INVESTMENTS INCLUDED IN THESE GROUPINGS?

A. No. Fleet capital, which is associated with the necessary replacement of vehicles and equipment that have reached their end of life, is addressed in the Direct Testimony of Company witness Mr. William K. Husen for all of the Company's business units.

B. Distribution Capital Budget Development and Management

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

A. In this section, I will provide an overview of Distribution's capital budgeting process, project development, and budget management processes. I note that I will describe the EV investments in detail separately in Section V.

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

A. The Distribution business area employs a "bottoms up" approach to budgeting and planning for the future needs of the distribution system. In coordination with the corporate budget process, the Distribution business area budgets for our work by identifying the necessary investments we need to make to the distribution system over the next five years. This includes both forecasting appropriate funding for our routine investments and identification of specific non-routine projects within the various capital groupings identified above in Section III.A. We utilize a comprehensive capital forecasting system to budget for and track these costs.

Distribution's annual capital budget is also dependent on the Company's overall finances and other business area needs. Company witness Ms. Melissa L. Ostrom explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and overall needs of the Company.

Q. GENERALLY SPEAKING, HOW DOES DISTRIBUTION DETERMINE ITS OVERALL CAPITAL BUDGET?

A. We begin our budgeting process in October by reviewing the recent summer peak loads to identify new or increased risks. In addition, our capital budget is dependent on the state of the economy, which has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. To obtain an accurate gauge of this work, our budgeting process begins with economic forecasting and analysis of historical spending trends to assess likely new business needs, required replacement of assets, and relocation of distribution facilities to accommodate road construction. We also assess the impacts of system growth on our capacity needs, including the risk of overloads and the system's ability to handle single contingency events.

Although economic factors drive much of our budget, we also must ensure that the existing system remains reliable. This includes proactively replacing assets near the end of their lives as well as budgeting for replacement of facilities due to unanticipated failure or damage such as those facilities damaged during storms. To budget for proactive replacements, we evaluate the age and condition of facilities and determine the amount of replacement or refurbishments that are needed in a particular year. To budget for unanticipated failures, we forecast the likelihood that assets will fail or be damaged, and the likely costs should they fail, based on historical trends. This analysis results in identification of capital projects that are needed for routine work necessary to maintain our existing system and the work required to support new customers or new construction.

Q. HOW IS THE CAPITAL EXPENDITURE BUDGET IMPLEMENTED AFTER APPROVAL?

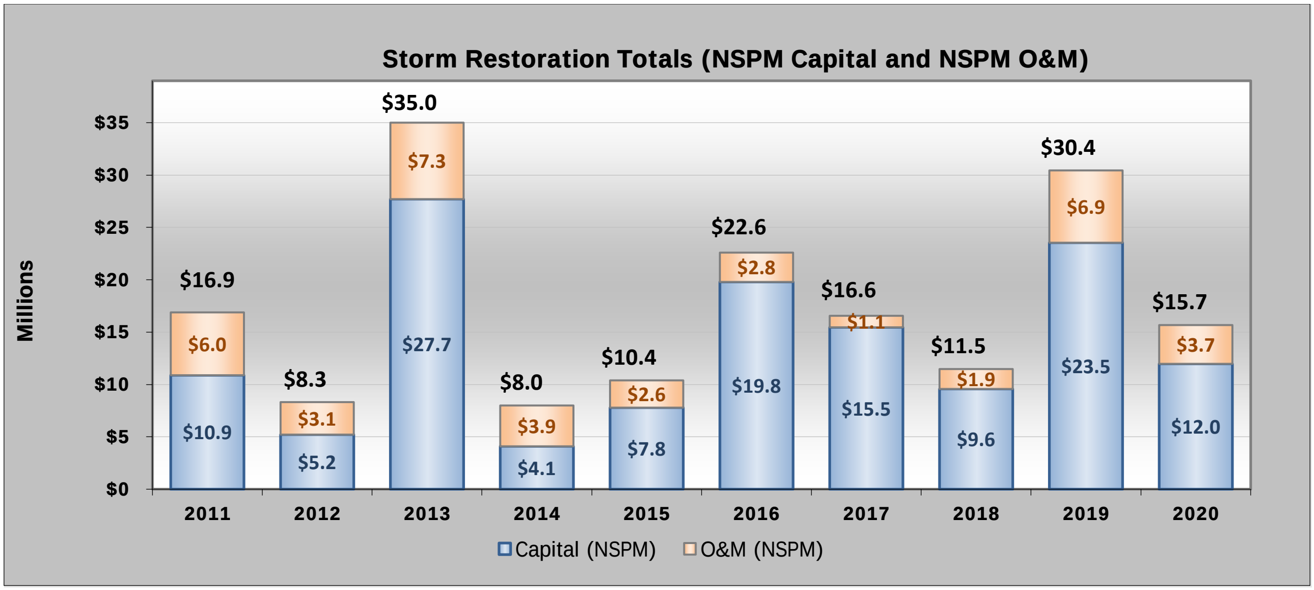
A. After the capital expenditures budget is finalized, the approved project list becomes the basis for the release of projects during the calendar year. This process must be somewhat flexible to allow for needed additions and deletions within a given year. For example, should an emergency occur during the year, priorities may change that then results in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. Through our budget deployment process we are therefore able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Q. CAN YOU PROVIDE AN EXAMPLE OF AN EMERGENCY THAT COULD IMPACT DISTRIBUTION'S BUDGET?

A. Yes. One of the primary examples is storm restoration. Our annual capital and O&M expenses for storm restoration are dependent on the magnitude and frequency of severe weather in a particular year. The unpredictable nature of severe weather makes precise budgeting difficult as the weather each year is different. The figure shows our capital and O&M storm restoration spend for the past 10 years and depicts how this spend is uneven year to year due to the unpredictable nature of storms.

Figure 1

Storm Restoration Capital and O&M



In certain years, such as 2013, 2016, and 2019, the frequency and severity of severe weather requires us to reallocate portions of our budget from another area to fund increased storm restoration work. Xcel Energy's storm response is industry-leading and award-winning. Our ability to reallocate our budgets allows us to promptly restore our customers' electric service as quickly as possible is essential to maintaining this level of storm response.

C. Distribution's 2018-2020 Capital Investment Trends

Q. FOR 2018-2020, WHAT WERE THE PRIMARY DRIVERS OF DISTRIBUTION'S CAPITAL ADDITIONS?

A. The primary drivers of Distribution's capital investments during these years were investments in our Asset Health and Reliability and Capacity categories. In the Asset Health and Reliability category, Distribution increased the number of pole and cable replacements as compared to prior years. The increase in pole replacements was due to a higher than average "rejection" rate (i.e., the proportion of poles that fail testing and need to be replaced) for poles inspected in 2018-2020. In 2017, our pole rejection rate was 9.5 percent and that rate climbed to 13.7 percent in 2018, 13.2 percent in 2019, and 16.4 percent in 2020.

The increase in the Asset Health and Reliability category was also due to an increase in storm restoration work. In 2019, there was significant storm restoration work to repair and replace facilities damaged due to the number and severity of storms that year. As shown in Figure 1 above, the Company had $23.5 million in capital expenditures (NSPM) in 2019 to replace facilities damaged by these storms. This work, which continued through 2020, also led to increased investments in Asset Health and Reliability.

In the Capacity category, Distribution completed several large projects in 2020 to address load growth on certain portions of the system. These projects included adding another transformer at both the St. Cloud Substation ($4.5 million) and the Hiawatha Substation ($3.2 million) along Hiawatha Avenue in south Minneapolis. We also completed the Rosemount Substation Project ($2.8 million) in 2020 which involved adding an additional transformer and feeder at that substation to support load growth in the area. The in-servicing of multiple large Capacity projects in 2020 drove up investments in this category as compared to prior years.

Q. PLEASE PROVIDE A BREAKDOWN OF THE COMPANY'S CAPITAL INVESTMENTS BY THE CAPITAL BUDGET CATEGORIES FOR 2018-2021.

A. Table 1 and Figure 2 provide a breakdown of our capital expenditures by capital budget grouping for 2018 to 2021. Table 2 and Figure 3 below provide a breakdown of our capital additions by capital budget grouping for 2018 to 2021.

Table 1

2018-2021 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast
Asset Health & Reliability	$99.7	$95.3	$126.7	$145.7
Advanced Grid Intelligence & Security (AGIS)	$0.4	$6.6	$2.7	$14.9
Electric Vehicle Program (EVP)	$0.0	$0.6	$0.1	$7.7
New Business	$62.2	$55.8	$59.1	$66.2
Capacity	$13.6	$21.6	$47.4	$32.6
Mandates	$28.9	$39.3	$33.6	$28.3
Tools and Equipment	$2.7	$4.9	$4.8	$10.7
Solar	($11.4)	($0.8)	$0.2	($1.4)
Total	**$196.2**	**$223.4**	**$274.5**	**$304.6**

Figure 2

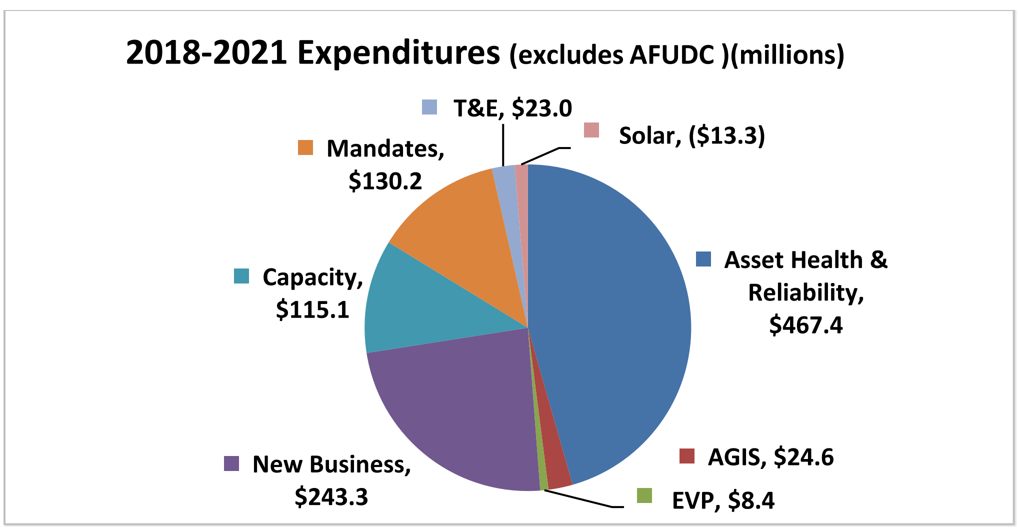


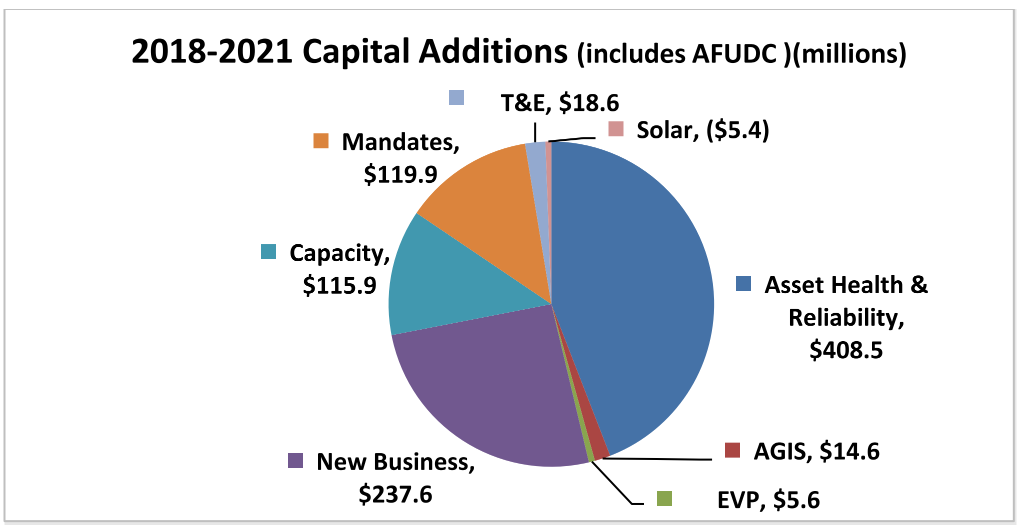
Table 2

2018-2021 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast
Asset Health & Reliability	$81.6	$87.3	$122.8	$116.8
Advanced Grid Intelligence & Security (AGIS)	$0.0	$4.7	$2.2	$7.7
Electric Vehicle Program (EVP)	$0.0	$0.5	$0.1	$4.9
New Business	$63.3	$56.3	$56.6	$61.4
Capacity	$10.6	$12.2	$33.4	$59.7
Mandates	$21.6	$29.2	$26.4	$42.8
Tools and Equipment	$2.5	$2.5	$4.9	$8.6
Solar	($13.2)	($2.1)	$24.6	($14.7)
Total	**$166.4**	**$190.6**	**$271.0**	**$287.3**

Figure 3



Q. PLEASE DISCUSS DISTRIBUTION'S CAPITAL INVESTMENTS IN 2021 SO FAR.

A. Our capital investments (as measured by capital additions) for 2021 are trending higher than recent historical actuals due primarily to increasing investments in our Capacity, Mandates, Tools and Equipment, and AGIS budget categories.

Our Capacity investments are increasing in 2021 due to several large projects that will be placed in service in 2021. One such project is the Wilson Substation Project in Bloomington, Minnesota, which accounts for $18.5 million in plant additions. The Wilson Substation Project is needed to mitigate multiple feeder overloads that are the result of steady load growth in recent years in the area served by the existing Wilson Substation. The Wilson Substation Project involves the installation of a fourth transformer, construction of three new distribution feeders, new manholes, and a new duct line. Another large Capacity project that will be completed in 2021 is the Plymouth Area Upgrade Project. This project involves expanding the existing Hollydale Substation in Plymouth, Minnesota and installing two new 69/13.8 kV transformers. This project also involves the construction of three new 13.8 kV feeders and other feeder reconfigurations in the area. The Plymouth Area Upgrade Project will result in $13.8 million in plant additions. Our Capacity projects are also driving increases in the Tools and Equipment category as each new substation requires the installation of new communication equipment to ensure the Company is able to obtain load and other system data from these new substation assets.

In the Mandate category, capital additions are higher due to several large multi-year mandate projects will be completed in 2021. For instance, the Fourth Street Project in Minneapolis will be placed in service in 2021, with total plant additions of $10.2 million. This Mandate project involves the relocation of Xcel Energy's existing underground primary and secondary cables, ductlines, and manholes that are in conflict with the modifications to Fourth Street as well as feeder extensions for tying into existing system where necessary and vault top restoration.

In 2021, Distribution is also starting work to build out our fiber optic communications network from our substations which is resulting in increases in our Tools and Equipment category.

Finally, our 2021 capital additions reflect continued work on the AGIS initiative for the Advanced Distribution Management System (ADMS) and start of implementation of FAN to support the start of the mass deployment of AMI meters beginning in 2022.

D. Overview of Distribution's 2022 - 2024 Capital Investments

Q. PLEASE PROVIDE AN OVERVIEW OF THE KEY DRIVERS OF DISTRIBUTION'S CAPITAL INVESTMENTS OVER THE TERM OF THIS MULTI-YEAR RATE PLAN.

A. The health of our distribution system assets is critical to our ability to ensure that our customers receive safe, reliable, and cost effective electricity. We make investments each year to maintain our vast system of overhead feeders and poles, underground cables, and substation equipment that form the last critical mile of electric system.

While our historical levels of investments have been sufficient to maintain our system in the past, we are now reaching the point where many of our assets are at or are past their anticipated useful life. As a result, we have been forecasting for several years the need for greater investments in our Asset Health and Reliability to make sure that we are able to replace assets that are in poor condition, like our overhead poles, and that we are able to replace assets closer to their estimated useful life, like substation transformers. These investments will allow us to maintain reliable service for our customers and will also allow us to harden our system as appropriate to make it more resilient to extreme weather events. For instance, we are installing larger, diameter poles to make our poles better able to withstand high winds and heavier ice loadings. We are also installing mainline underground cable in conduits to better protect these assets from the elements.

During this multi-year rate plan we will also be adding several new subprograms within the Line Renewal program to address aging equipment, reliability issues, and to better support DER interconnection. In particular, in 2022 we will commence our Community Solar Gardens (CSG) Recloser program to install electronic reclosers on both new and existing CSG to reduce the frequency and duration of planned outages.[4] An electronic recloser is a high voltage electric switch, akin to a larger (more powerful) breaker on household electric lines. When trouble occurs on the system, the recloser flips to the open position, shutting off power. Figure 4 shows an actual recloser in the field. The installation of these electronic reclosers will minimize the impacts to CSG during planned outage events and will increase worker safety through the adjustment of protection settings.

[4] The Company discussed this planned installation as part of its September 1, 2021 compliance report in the CSG docket. *Compliance Report – Planned Outages*, IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF ITS PROPOSED COMMUNITY SOLAR GARDENS PROGRAM, Docket No. E002/M-13-867 (Sept. 1, 2021).

Figure 4

Electronic Recloser

We will also be investing in needed capacity improvements as part of our Capacity budget category to serve existing loads and areas where load is increasing on our system. One such project is at our Midtown Substation located in near Lake Street in Minneapolis, Minnesota. The project will provide additional capacity to serve existing load in the area, as well as providing capacity to accommodate future load growth.

During the term of this MYRP, Distribution will continue work on implementing the AGIS initiative including commencing the mass deployment of AMI meters and the associated FAN throughout the service territory as well the installation of FLISR. These AGIS investments will advance the capabilities of our distribution grid, increase our system visibility and control, and enable more customer options. In addition, our FLISR investments will enable the Company to better and more quickly respond to outages on the system. As noted above, the Company plans to seek recovery for the bulk of the AGIS investments (with the exception of FLISR and internal labor) through the TCR Rider.

From 2022 to 2024, we are also continuing to work on our existing EV programs as well as expanding our EV offerings. This includes work on several pilot programs that were previously approved by the Commission, the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot,[5] as well as for four new pilots and programs that are currently before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending before the Commission.[6] In that docket, stakeholders expressed interest in an initial, smaller rebate program, and the Company did not object to a smaller initial program size. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket. These investments will provide the infrastructure necessary to promote greater EV use, and to meet the demands of the growing EV market. I discuss our EV capital investments and O&M expenses in Section V.

Q. WHAT ARE DISTRIBUTION'S CAPITAL FORECASTS FOR 2022-2024 BY CAPITAL BUDGET GROUPING?

A. Our capital expenditure forecasts for 2022 through 2024 are set forth in Table 3 and Figure 5. A breakdown of the total capital expenditures that will be recovered in the TCR Rider versus base rates is provided in Table 4. Our capital additions forecasts for 2022 through 2024 are set forth in Table 5 and Figure 6. A breakdown of the total capital additions that will be recovered in the TCR

[5] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.
[6] Docket No. E002/M-20-745.

Rider versus base rates is provided in Table 6. Our individual capital additions are listed in Exhibit___(KAB-1), Schedule 2.

Table 3

2022-2024 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Asset Health & Reliability	$191.0	$205.1	$212.3
Advanced Grid Intelligence & Security (AGIS)	$92.8	$138.3	$116.6
Electric Vehicle Programs (EVP)	$94.1	$63.1	$59.1
New Business	$60.7	$61.9	$61.9
Capacity	$38.9	$40.8	$50.9
Mandates	$32.4	$32.2	$36.6
Tools and Equipment	$14.7	$15.4	$14.2
Solar	$0.0	$0.0	$0.0
Total	**$524.6**	**$556.9**	**$551.5**

Table 4

2022-2024 Distribution Capital Expenditures Base Rates vs. TCR Rider

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Total Distribution Base Rates	$448.8	$445.7	$461.2
Total Distribution TCR Rider	$75.8	$111.2	$90.3
Total	**$524.6**	**$556.9**	**$551.5**

Figure 5

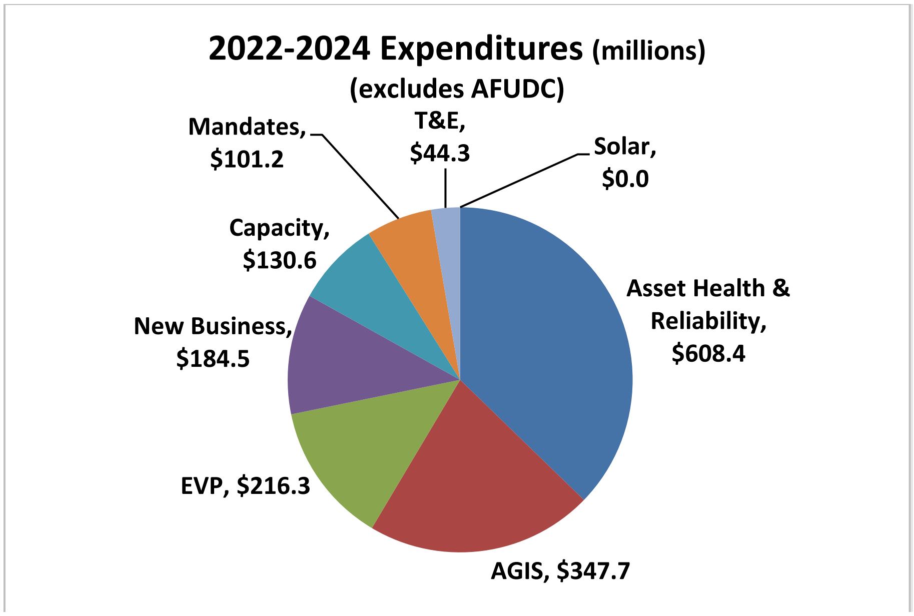


Table 5

2022-2024 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Asset Health & Reliability	$168.9	$180.8	$205.0
Advanced Grid Intelligence & Security (AGIS)	$88.6	$118.7	$131.2
Electric Vehicle Programs (EVP)	$79.1	$69.7	$60.5
New Business	$60.5	$61.3	$61.5
Capacity	$33.2	$41.4	$53.0
Mandates	$28.0	$29.2	$33.5
Tools and Equipment	$12.6	$14.1	$14.3
Solar	($0.2)	($0.0)	($0.0)
Total	**$470.7**	**$515.2**	**$558.9**

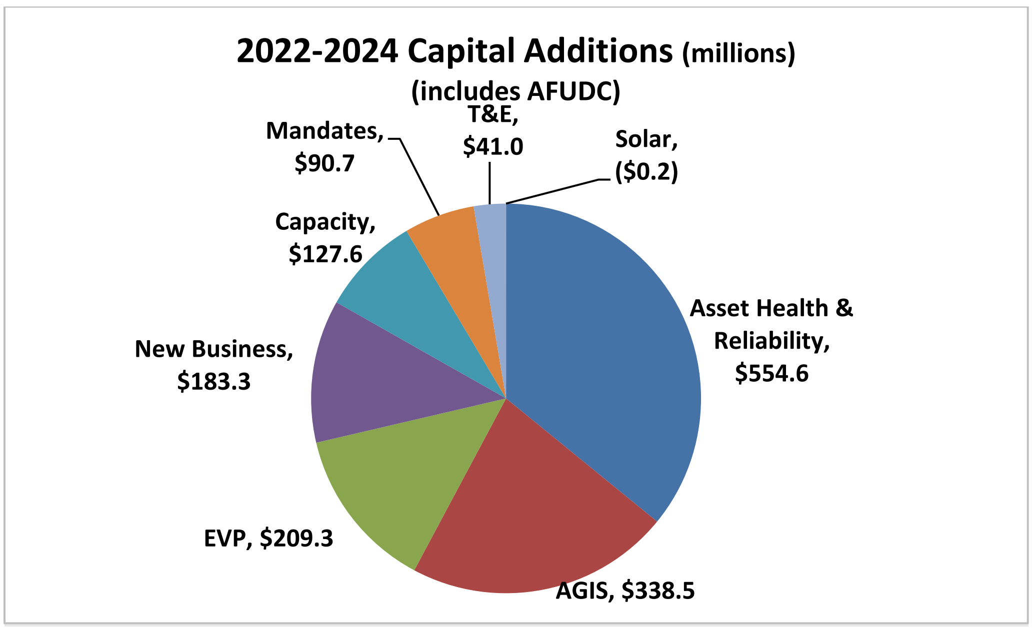
Table 6

2022-2024 Distribution Capital Additions Base Rates vs. TCR Rider

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Total Distribution Base Rates	$395.1	$416.9	$452.6
Total Distribution TCR Rider	$75.6	$98.3	$106.3
Total	**$470.7**	**$515.2**	**$558.9**

Figure 6



Q. HOW DO DISTRIBUTION'S CAPITAL ADDITIONS FOR 2022 TO 2024 COMPARE TO HISTORICAL TRENDS?

A. As I noted earlier, overall, Distribution's capital investments are increasing in 2022 to 2024 as compared to historical trends. The budget category with the largest growth is our Asset Health and Reliability budget category. Our investments in this budget category are crucial to maintaining the reliability and resiliency of our system and ensuring it is poised to meet future demands of a modern grid.

As I discussed, we have a number of assets on our system that are at or are approaching the end of their useful. To address these aging assets and to replace assets closer to their lifecycle we are making greater investments in our Pole Replacement program and Substation Renewal programs. We are also adding several new programs to our Line Renewal Program to address aging equipment, reliability issues, and to better support DER interconnections.

Q. CAN YOU PROVIDE AN OVERVIEW OF INVESTMENTS PLANNED FOR DISTRIBUTION'S OTHER CAPITAL BUDGET CATEGORIES DURING THE TERM OF THE MYRP?

A. Yes. Distribution will also be increasing our investments in Capacity projects from 2022 through 2024 by completing eight large discrete Capacity projects to address potential overload conditions at substations throughout our service territory. We are also investing in our Feeder Load Monitoring Program to install Supervisory Control and Data Acquisition (SCADA) at our substations and in a Grid Reinforcement Program to replace overloaded feeders and service transformers to support additional load growth.

Further, during 2022 to 2024, Distribution will be installing AMI meters and the associated FAN communication network which will led to increasing capital investments in our AGIS initiative budget category. During this period, Distribution will also continue work on installing FLISR devices. Recovery for the Company's capital investments in AMI, FAN, and ADMS (with the exception internal labor) will be requested through TCR Rider as discussed by Company witness Mr. Benjamin C. Halama. Recovery of the Company's investments in FLISR are being sought in this case.

While Tools and Equipment is a smaller category of investments for Distribution, we will be expanding our investments in this category to build out fiber optic communications from our substations, improve our cyber security, and to enable remote monitoring of the downtown portion of our distribution system.

Finally, another area of growth is our investments in EV infrastructure. The Company has received Commission approval for several different pilots and programs aimed at making it easier for more people to use EVs through new charging infrastructure and customer programs. The Company also expects to launch several new pilots and programs during the term of this MYRP.

Q. CAN YOU PROVIDE AN OVERALL VIEW OF DISTRIBUTION'S CAPITAL INVESTMENT TREND FROM 2018 TO 2024?

A. Yes. Our overall 2018 to 2024 capital expenditures and capital additions are set forth in Tables 7 and 8 below. Table 9 below provides a breakdown of the AGIS capital additions for Distribution that are planned to be recovered in TCR Rider as opposed to base rates. As I stated earlier, internal labor for ADMS, AMI, and FAN will be recovered in base rates but the remainder of the Distribution portion of the capital costs for these projects will be recovered in the TCR Rider.

Table 7

2018-2024 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Health & Reliability	$99.7	$95.3	$126.7	$145.7	$191.0	$205.1	$212.3
Advanced Grid Intelligence & Security (AGIS)	$0.4	$6.6	$2.7	$14.9	$92.8	$138.3	$116.6
Electric Vehicle Program (EVP)	$0.0	$0.6	$0.1	$7.7	$94.1	$63.1	$59.1
New Business	$62.2	$55.8	$59.1	$66.2	$60.7	$61.9	$61.9
Capacity	$13.6	$21.6	$47.4	$32.6	$38.9	$40.8	$50.9
Mandates	$28.9	$39.3	$33.6	$28.3	$32.4	$32.2	$36.6
Tools and Equipment	$2.7	$4.9	$4.8	$10.7	$14.7	$15.4	$14.2
Solar	($11.4)	($0.8)	$0.2	($1.4)	$0.0	$0.0	$0.0
Total	**$196.2**	**$223.4**	**$274.5**	**$304.6**	**$524.6**	**$556.9**	**$551.5**

Table 8

2018-2024 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Health & Reliability	$81.6	$87.3	$122.8	$116.8	$168.9	$180.8	$205.0
Advanced Grid Intelligence & Security (AGIS)	$0.0	$4.7	$2.2	$7.7	$88.6	$118.7	$131.2
Electric Vehicle Program (EVP)	$0.0	$0.5	$0.1	$4.9	$79.1	$69.7	$60.5
New Business	$63.3	$56.3	$56.6	$61.4	$60.5	$61.3	$61.5
Capacity	$10.6	$12.2	$33.4	$59.7	$33.2	$41.4	$53.0
Mandates	$21.6	$29.2	$26.4	$42.8	$28.0	$29.2	$33.5
Tools and Equipment	$2.5	$2.5	$4.9	$8.6	$12.6	$14.1	$14.3
Solar	($13.2)	($2.1)	$24.6	($14.7)	($0.2)	($0.0)	($0.0)
Total	**$166.4**	**$190.6**	**$271.0**	**$287.3**	**$470.7**	**$515.2**	**$558.9**

Table 9

2018-2024 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Total Distribution Base Rates	$166.4	$185.9	$269.3	$281.7	$395.1	$416.9	$452.6
Total Distribution TCR Rider	$0.0	$4.7	$1.7	$5.6	$75.6	$98.3	$106.3
Total	**$166.4**	**$190.6**	**$271.0**	**$287.3**	**$470.7**	**$515.2**	**$558.9**

Tables 7 and 8 illustrate that Distribution's capital investments can vary on a year-to-year basis depending on the specific work that is necessary to meet the needs of both our customers and our business. In certain years, Distribution's capital investments may be lower to support increased investments by other business areas of the Company. Conversely, Distribution's capital investment levels may increase in years when we are working on major initiatives, and capital additions necessarily increase when those initiatives are placed in service.

As can be seen in the tables above, incremental capital additions increases for 2022-2024 over previous years are the result of greater investment in the following budget categories: Asset Health and Reliability, EVs, AGIS, Capacity, and Tools and Equipment. As discussed above, this increase in investments in necessary to maintain the safety, reliability, and resiliency of the distribution system and to meet the requirements of a modern grid.

E. Major Planned Investments for 2022 to 2024

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

A. The multi-year rate plan statute, Minn. Stat. § 216B.16, subd. 19, requires that a utility provide "a general description of the utility's major planned investments over the plan period." This section of my testimony discusses the major planned investments Distribution anticipates making in 2021 through 2023.

Q. How did Distribution identify its major planned investments over the plan period?

A. To identify these investments, we looked for those unique capital projects that will require a greater than normal quantity of Distribution resources to complete and that contribute a significant amount to our budgeted capital additions.

Q. What major planned investments does Distribution anticipate undertaking during the period of this multi-year rate plan?

A. Distribution anticipates undertaking two major planned investments from 2022 to 2024. These are in our Routine Cable Replacement and Routine Pole Replacement programs. Both of these programs are long-standing programs but during this rate case period, the Company will be making steady investments in these programs, as depicted in Table 10. These major planned investments, as well as the additional key capital projects Distribution anticipates completing in 2022, 2023, and 2024 are discussed in more detail below.

Table 10

Distribution's Major Planned Investments

	Capital Additions (Dollars in Millions)		
	2022	**2023**	**2024**
Cable Replacement Program	$32.7	$34.3	$35.4
Pole Replacement Program	$31.3	$33.8	$34.3

F. Key Capital Additions for 2022 to 2024

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

A. The purpose of this section is to describe key capital projects for Distribution during the term of the multi-year rate plan. For purposes of testimony, we defined key capital projects as those that will have approximately $4 million or more in capital additions between 2022 and 2024. These projects are described in detail below. Unless otherwise stated, all dollar figures in this capital section are State of Minnesota Electric Jurisdiction amounts. Individual project capital additions are listed in Exhibit___(KAB-1) Schedule 2.

1. Asset Health and Reliability

Q. WHAT TYPES OF CAPITAL PROJECTS ARE INCLUDED IN THE ASSET HEALTH AND RELIABILITY CATEGORY?

A. Asset Health and Reliability is Distribution's largest capital budget category as these investments are essential to ensuring that our distribution remains safe and reliable. These are projects that we perform each year to address the age and condition of our distribution facilities. To determine which facilities need replacement or repair each year we track the age of our major distribution assets and use age as a proxy for asset health. We also analyze reliability data and work to address those components that have poor reliability performance.

Distribution's investments in Asset Health and Reliability fall into two larger categories – routine projects and larger discrete projects. Routine projects are those that are performed each year to replace aging and worn distribution facilities based on the age profile and overall reliability performance of these facilities. This includes replacement of underground cable, poles, and substation equipment which have reached the end of their life. This category also captures replacements due to storms and public damage.

In addition to these routine projects that we perform each year, Distribution also undertakes discrete Asset Health and Reliability projects that relate to asset renewal (addressing aging infrastructure with specific conversion or upgrade projects) or reliability (where the age of facilities impacts failures, reliability, and customer outages). Due to the timing of in-service dates, the capital additions for these discrete projects varies on a year-to-year basis. Table 11 provides a breakdown of the planned capital additions in the Asset Health and Reliability category for 2022 through 2024.

Table 11

2018-2024 Capital Additions – Asset Health and Reliability

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Health and Reliability							
Cable Replacement Program	$22.3	$18.5	$27.8	$24.2	$32.7	$34.3	$35.4
Pole Replacement Program	$7.4	$7.9	$23.9	$31.1	$31.3	$33.8	$34.3
Routine Rebuilds and Conversions	$22.4	$29.8	$29.4	$31.0	$31.9	$33.3	$34.1
Restoration/Failure Reserves	$10.5	$8.9	$25.8	$11.4	$26.3	$26.8	$26.6
Line Renewal Programs	$2.6	$9.7	$1.8	$7.9	$25.6	$13.7	$24.4
Substation Renewal Programs	$5.8	$3.2	$2.0	$3.3	$19.1	$23.2	$24.2
Discrete Projects	$10.5	$9.4	$12.2	$7.9	$2.0	$15.6	$25.9
Total	**$81.6**	**$87.3**	**$122.8**	**$116.8**	**$168.9**	**$180.8**	**$205.0**

Q. TABLE 11 SHOWS INCREASING CAPITAL ADDITIONS IN THE ASSET HEALTH AND RELIABILITY CATEGORY FROM 2022 THROUGH 2024. WHAT IS DRIVING THIS INCREASED INVESTMENT?

A. This increasing trend is driven by greater investments in our Substation Renewal programs as well as one large discrete Asset Health and Reliability project that will be placed in service in 2024. We are planning to increase our investments in our Substation Renewal programs to move towards replacing these assets closer to the end of their useful life. As discussed above, there are a number of transformers on our system that are beyond their expected useful life of 55 years, and we risk a greater number of transformer failures, and resulting outages for customers, if these assets are not replaced in a timely manner.

In 2024, we are also planning to in-service a large discrete project, the Dayton's Bluff Reinforcement Project. This project involves rebuilding a key substation in downtown St. Paul. The existing transformers at this substation, along with other components, are reaching their end of life and need to be replaced to maintain the reliability of this substation. This project has total capital additions of $20.3 million in 2024.

a. Pole Replacement Program

Q. DESCRIBE THE POLE REPLACEMENT PROGRAM?

A. The NSPM distribution system has approximately 500,000 wooden poles in service. Pole longevity can vary widely based on the wood species, treatment and the environment where it is placed but poles have a useful life, on average, of approximately 50 years. As part of the Pole Replacement program, Distribution assesses poles, treats poles, and replaces poles that have reached the end of their life. Xcel Energy, along with utilities across the country, has a significant number of poles that are more than 50 years old. This is due to the fact that there was large buildout of the distribution system in the 1950s and 1960s in response to the population growth and suburban expansion during this time. While these poles have performed well for the past 60-70 years, these poles are now reaching the end of their life. Given the advanced age of our poles, it is important that Distribution maintain a steady assessment and replacement schedule so that any issues with our poles can be identified and rectified prior to a pole failure.

Q. PLEASE DESCRIBE THE POLE ASSESSMENT PROCESS.

A. Our pole assessment process was designed to ensure compliance with National Electric Safety Code (NESC) standards that require wood poles to be replaced or rehabilitated when the structure strength of the pole is reduced to 2/3 of that required when installed for NESC loading. Xcel Energy takes a slightly more conservative approach than that required by the NESC and replaces any pole when its structure strength is at less than 70 percent.

Our pole assessment process includes a visual, sound and bore, and/or excavation assessment (i.e., hand digging around the base of pole). Depending on the results of this assessment, poles will be replaced as appropriate. The determination of whether or not a pole needs to be replaced depends on the remaining groundline strength of the pole and existence of any above ground deterioration (i.e., pole top decay).

If a pole has less than 70 percent of its initial strength left or exhibits severe above ground deterioration, the pole is replaced. If a pole needs to be replaced, we typically plan to replace the pole the following calendar year unless the pole is in such poor condition that it requires immediate replacement. While we plan to replace poles the next calendar year after a failed assessment, there may be situations where certain poles are not replaced in the following calendar year. If a pole is not replaced in the following calendar year then it is prioritized for replacement in the year after. We typically group poles together and complete all replacements in an area to be the most cost effective.

Q. HOW DOES THE COMPANY'S POLE REPLACEMENT PROGRAM BENEFIT CUSTOMERS?

A. The Company's distribution poles are a key component of the distribution system that enables the distribution of electricity to homes and businesses. Our Pole Replacement program benefits our customers by ensuring that these assets remain in good working order for both the reliability of our system and the safety of our customers.

Q. PLEASE SUMMARIZE DISTRIBUTION'S HISTORICAL INVESTMENTS IN ITS POLE REPLACEMENT PROGRAM.

A. Table 12 below provides a summary of the actual, forecasted, and budgeted capital additions in the Pole Replacement program from 2018 through 2024. As shown in this table, Distribution began increasing its capital investments in the Pole Replacement program beginning in 2020 and this trend of increased investment is continuing through 2024.

Table 12
2018-2024 Capital Additions – Pole Replacement Program
(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Pole Replacement Program	$7.4	$7.9	$23.9	$31.1	$31.3	$33.8	$34.3

Q. HOW WAS THE 2022-2024 BUDGET FOR THE POLE REPLACEMENT PROGRAM DEVELOPED?

A. Our budget for the Pole Assessment program is based on an assumption that we will assess 1/12th of all of our poles each year (or 8.3 percent) and that approximately 12 percent of the poles assessed each year will need to be replaced in the following calendar year. The number of poles budgeted to be replaced each year is then multiplied by the cost to replace each pole which are estimated on a per-pole basis, using historical data and any known anticipated changes in labor and material costs.

Q. WHY ARE INVESTMENTS IN THE POLE REPLACEMENT PROGRAM INCREASING OVER TIME?

A. Our investments in this area started increasing in 2020 due to a review of our pole assessment practices, the condition and advanced age of the poles on our system, and use of a stronger, higher class pole that is more expensive.

Q. WHY DID THE COMPANY REASSESS ITS POLE ASSESSMENT PRACTICES?

A. While Xcel Energy began its pole assessment program in 2007, the Company reassessed this program in 2020 to ensure that we were timely identifying and replacing poles in poor condition given the age of our poles. We also wanted to make sure that the new poles that we installed were better able to withstand high winds, ice storms, or other extreme weather events.

Q. WHAT SPECIFIC CHANGES DID THE COMPANY MAKE TO ITS POLE ASSESSMENT PRACTICES IN 2020?

A. As a result of this reassessment, the Company recommitted to provide adequate funding to assess our distribution poles on a 12-year cycle (or assessing approximately 8.3 percent of all of our poles each year). In addition, the Company changed our pole standards to move up to the next higher class of poles (NESC Grade C to NESC Grade B). This was done because these higher class, and slightly larger diameter, poles were found to hold up better under stress tests such as a tree or a large branch falling on a line. These larger diameter poles however increased the material costs for each pole replacement.

Q. ARE THERE OTHER FACTORS THAT ARE CONTRIBUTING TO THE NEED FOR INCREASED INVESTMENTS IN POLE REPLACEMENTS?

A. Yes, in recent years we have seen a higher than average rejection rate for assessed poles that has resulted in the need to replace a greater number of poles each year. A "rejection" refers to a non-compliant pole with less than 70 percent remaining groundline strength or severely damaged top that needs to be replaced to ensure the physical integrity of the pole. For instance, from 2018 through 2020, the average annual rejection rate was approximately 14 percent per year whereas the average historical rejection rate from 2010 through 2017 was approximately 8.4 percent. While the rejection rate for poles can fluctuate each year based on the age and condition of the particular poles assessed in that year this recent increase in the rejection rate underscores the need to place greater focus on assessment and replacement of these key assets.

Table 13

NSPM Pole Rejection Rates By Year

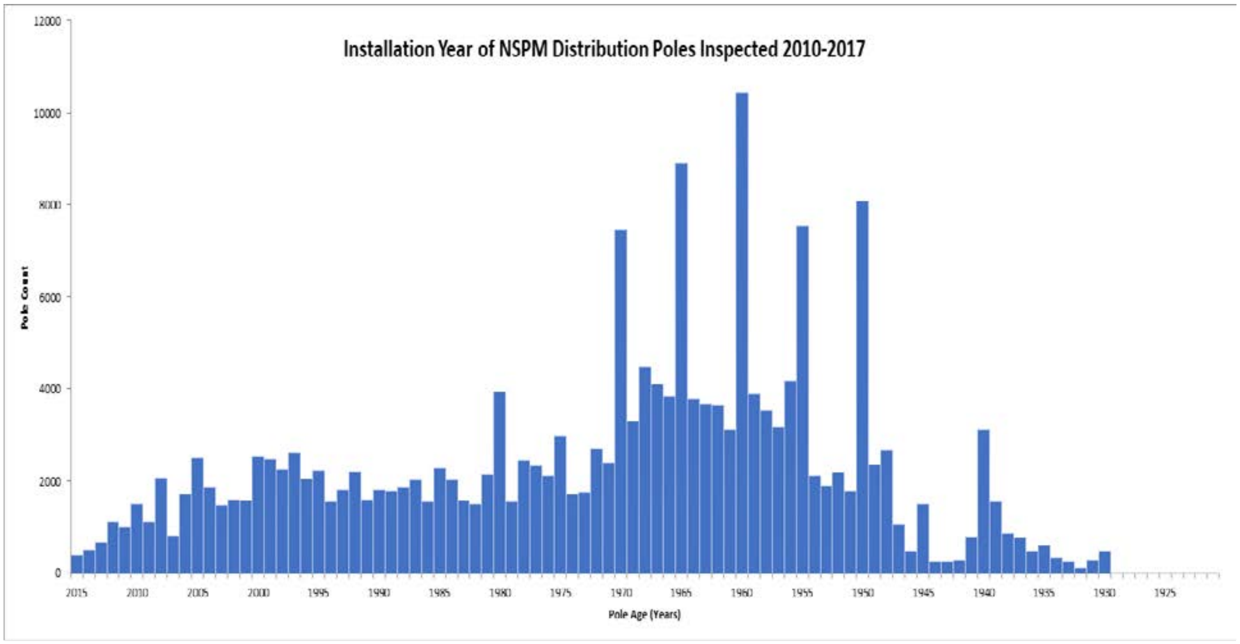
Year	Rejection Rate
2020	16.4%
2019	13.2%
2018	13.7%
2017	9.5%
2016	10.4%
2015	11.0%
2014	10.2%
2013	9.5%
2012	7.3%
2011	4.7%
2010	4.6%

Q. WHY IS THE REJECTION RATE FOR POLES INCREASING IN RECENT YEARS?

A. This increase is a product of the age and condition of our poles. Our wood poles have an expected useful life of approximately 65 years. Currently, there are a quite a few poles on our system that are between 60-70 years old as they were installed in the 1950s and 1960s when there was a significant growth in the state's population. Figure 7 below shows the installation year of the approximately 200,000 poles that were inspected by the Company between 2010 and 2017. As seen in this figure, a large portion of the poles that were inspected in that time period were between 50-70 years old with the highest percentage being near 60 years old.

While the age of a pole is not necessarily indicative of its condition, older poles are more likely to be in poor condition given the length of time that they have been exposed to the elements. As a result, we have found that the percentage of poles requiring replacement is highly correlated with age. Given the age of our current poles, we expect that the percentage of poles requiring replacement to continue to increase until we have assessed and made any necessary replacements across our entire service territory. If Distribution stays on its 12-year cycle with regard to pole assessments and replacements, we anticipate that we will complete an initial assessment all of the poles on our system by the end of 2024.

Figure 7



Q. ARE THERE ANY OTHER FACTORS THAT ARE CONTRIBUTING TO THE INCREASED CAPITAL COSTS FOR POLE REPLACEMENTS?

A. Another factor that is contributing to the increasing capital costs for pole replacements is the increase in material and labor costs for each pole replacement due to inflationary increases. As mentioned above, the move to a higher class of pole in 2020 led to an increase in the material cost for each pole.

b. Cable Replacement Program

Q. DESCRIBE THE CABLE REPLACEMENT PROGRAM.

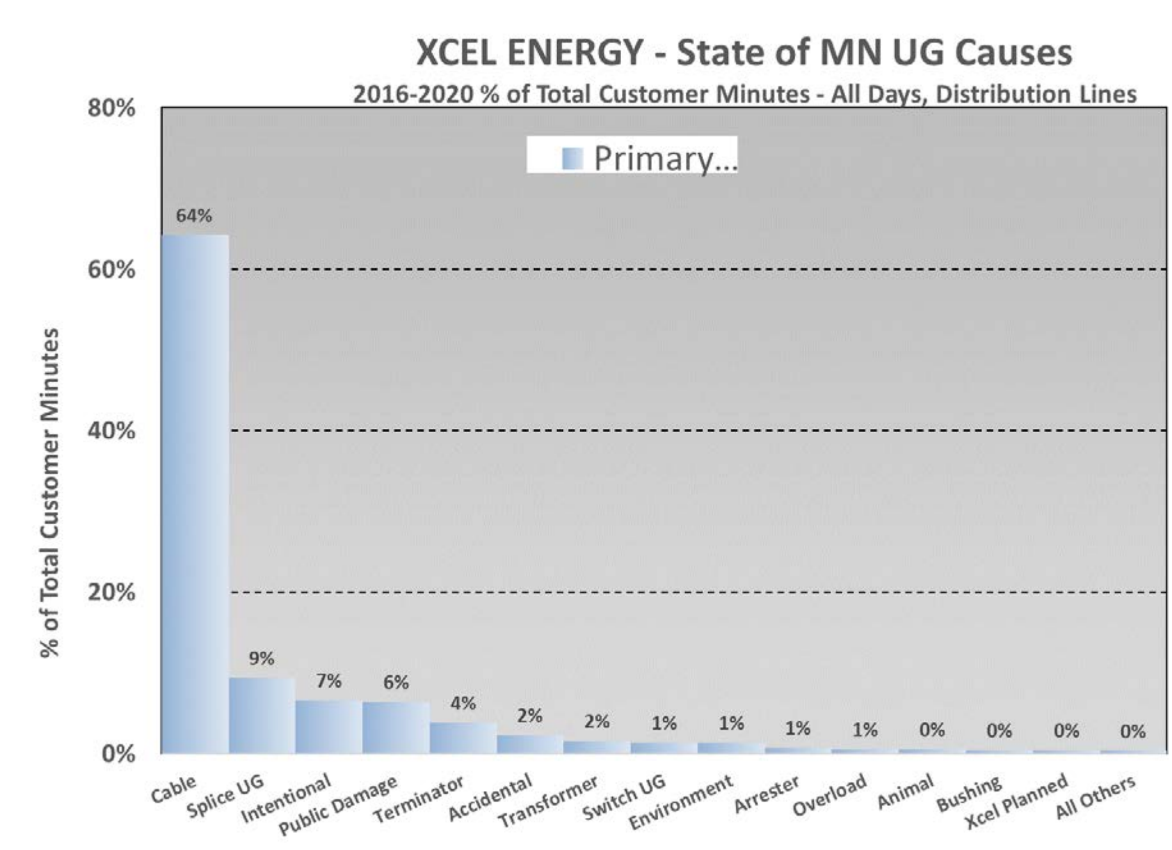
A. The Minnesota portion of the NSPM distribution system has over 1,600 miles of underground mainline cable and over 8,600 miles of underground tap cable. To maintain these assets, the Company has two subcategories of investment within its cable replacement program: (1) mainline cable replacements and (2) underground residential distribution (URD) cable replacement. Mainline cable is the backbone of our underground cable distribution system. Mainline cable is typically larger (500 kcmil or greater), multi-phase cable that originates from the substation and that then supplies our smaller cable feeder system. URD cable is smaller cable that is constructed in a loop arrangement, segmented by distribution transformers, to serve individual customers. The cable replacement program replaces cable that is either damaged beyond repair or that has failed more than once in a two year period.

Q. HOW DOES THE CABLE REPLACEMENT PROGRAM BENEFIT CUSTOMERS?

A. As shown in Figure 8 below, cable failures are a main contributor to outages for customers who are served by underground facilities and accounted for approximately 65 percent of the customer minutes out (CMO) on the underground system from 2016 to 2020. The cable replacement program responds to outages caused by cable failures and reactively replaces these cables to avoid future outages from failing cable. As funding is available, this program also proactively replaces cable that has a poor performance history to improve the reliability of service for our customers.

Figure 8

State of Minnesota Underground Outages by Cause



Q. HOW IS THE BUDGET FOR THE CABLE REPLACEMENT PROGRAM DEVELOPED?

A. The largest portion of our cable replacement budget is for reactive cable replacements which means that we are replacing cable after it has already failed. As a result, the budget for this category is developed based on historical failure/fault rates for both mainline and URD cable. In 2022, our mainline cable budget also includes additional funding for conduit construction (i.e., placing the mainline cable in a conduit as opposed to direct burying it). Our cable replacement budget for 2022 through 2024 also reflects additional funds to make proactive cable replacements for both mainline and URD cable more achievable in years when failure rates are lower than projected. Finally, this budget include yearly inflationary increases for both material and labor costs. The table below provides actual, forecast, and budget information for our cable replacement program from 2018 through 2024.

Table 14
2018-2024 Capital Additions – Cable Replacements
(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Cable Replacement	$22.3	$18.5	$27.8	$24.2	$32.7	$34.3	$35.4

Q. WHY IS THE BUDGET FOR CABLE REPLACEMENTS INCREASING DURING THE TERM OF THIS MYRP (2022-2024) AS COMPARED TO PRIOR YEARS?

A. There are four primary drivers of this increase: (1) a rise in reactive cable replacements in 2020, (2) a transition to conduit construction for mainline cable replacements, (3) funding for proactive cable replacements starting in 2022, and (4) inflationary increases in labor and materials.

Q. WHY DOES AN INCREASE IN REACTIVE CABLE REPLACEMENTS IN RECENT YEARS RESULT IN HIGHER BUDGETS FOR CABLE REPLACEMENTS DURING THE MYRP?

A. The majority of the cable replacement program budget is reserved for replacing both mainlines and URD cable after it has failed. To ensure that we have adequate funding to respond to these failures, we develop our budgets based on recent historical cable failure rates. As shown in the figures below, we saw increases in mainline cable failures in both 2019 and 2020 and increases in URD cable failures in 2020. This increase in cable failures required more reactive replacements as compared to prior years. To develop our 2022-2024 budgets, we relied on the most recent cable failure data, which was 2020, and utilized that failure rate to determine a reasonable budget for reactive replacements. This resulted in an increase in our reactive cable replacement budget for 2022-2024 to make certain that we have adequate funding to make all of the necessary reactive replacements based on recent failure trends.

Figure 9

Mainline Cable Failures

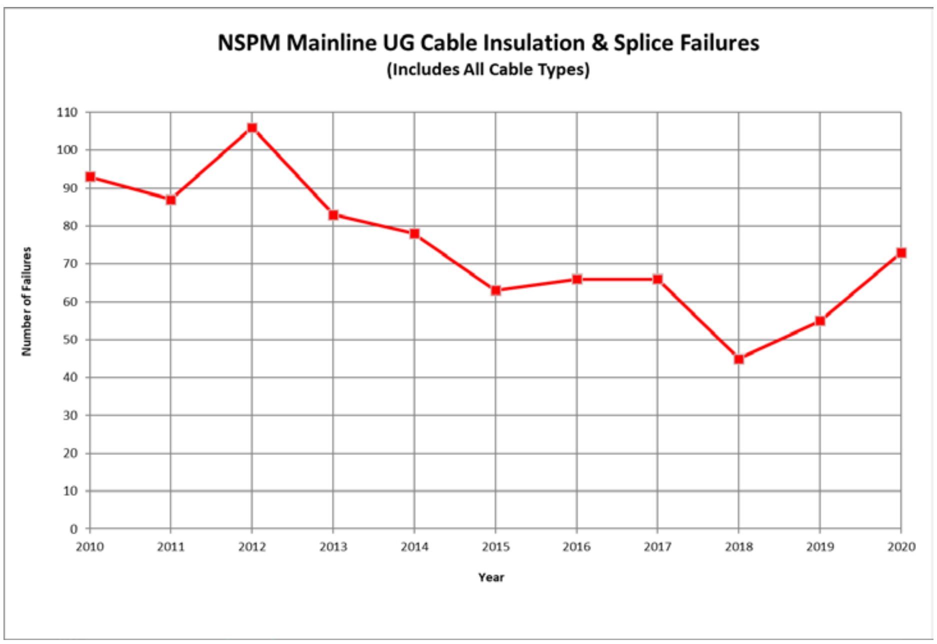
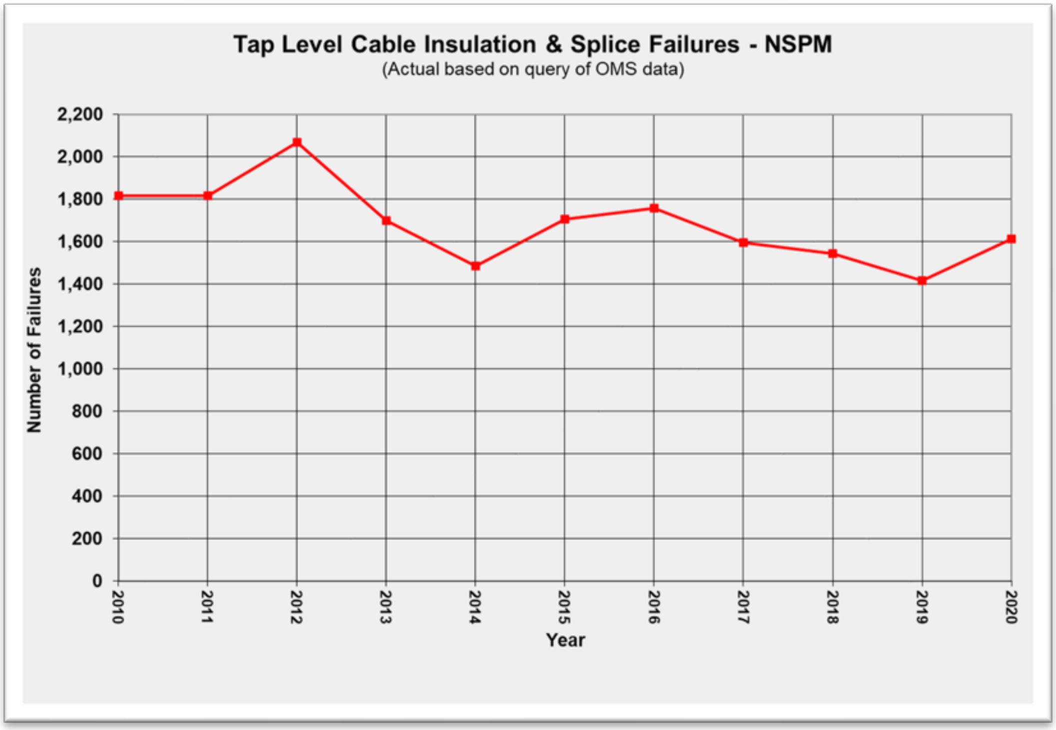


Figure 10

URD Cable Failures



Q. WHY ARE CABLE FAILURES INCREASING?

A. This increase in cable failures is attributed to several of factors. One factor is the particular type of cable that was installed beginning in the late 1960s when there was a shift to underground construction for mainline and feeders for new residential developments. The type of cable that was used during this time period was the early generation of non-jacketed cross-linked polyethylene (XLPE) insulated cables. This non-jacketed cable, which was installed up until 1985, is more prone to failure and has a shorter useful life (approximately 27-34 years on average) than newer cable types that we currently install (approximately 40 years on average). This is because without the jacket, these cables experience faster deterioration and have a higher chance of concentric neutral deterioration. At least 20 percent of the Company's underground cable in Minnesota is this non-jacketed XLPE cable which is also likely contributing to this increase in failures in recent years.

We also believe that the increase in URD cable failures in 2020 may be the result of increased stress due to higher load on the URD cables from changes in load patterns due to the COVID-19 pandemic. As a result of COVID-19 restrictions in 2020, we saw an increase in loads on our residential distribution system. These increased loads resulted in more stress on these cables and likely contributed to shortened life spans.

Q. HOW DOES CONDUIT CONSTRUCTION IMPACT THE 2022-2024 BUDGETS FOR MAINLINE CABLE REPLACEMENTS?

A. Beginning in 2022, Xcel Energy will be placing mainline cable in a conduit as opposed to direct burying this cable. This type of construction is more costly than direct burying due the fact that this type of installation is more time consuming which increases labor costs. Conduit construction is also more costly due to higher material costs. Material costs are higher for conduit construction because it requires more expensive, higher capacity (lower resistance) cable in order to ensure that the temperature of the cable stays within operating limits when it is placed in the conduit. Direct buried cable is able to dissipate heat through direct contact with the ground. There are also additional material costs associated with the conduit itself.

While more costly conduit installation results in improved reliability as compared to direct bury installation. This is because cable placed in conduit is protected from the elements as well as wildlife such as gophers. Conduit construction also makes the cable easier to locate and access for inspection, maintenance, and repair. Since cable placed in conduit are easier to locate and access when it does fail, outage times are reduced as compared to direct buried cable.

Q. HOW ARE PLANNED PROACTIVE CABLE REPLACEMENTS IMPACTING THE 2022-2024 BUDGET FOR CABLE REPLACEMENTS?

A. During the term of this multi-year rate plan, the Company has increased its cable replacement budget to perform proactive mainline and URD cable replacements. As noted, the majority of the budget in this program is dedicated to replacing cable that have already failed. If reactive failures are lower than forecasted, the Company utilizes the remaining budget to perform proactive replacements of cable that has a history of poor reliability. The 2022-2024 budgets include a modest increase as compared to prior years to make these proactive replacements more possible. These proactive replacements will be aimed at addressing mainline and URD cable that has poor reliability performance and replacing them before they fail again.

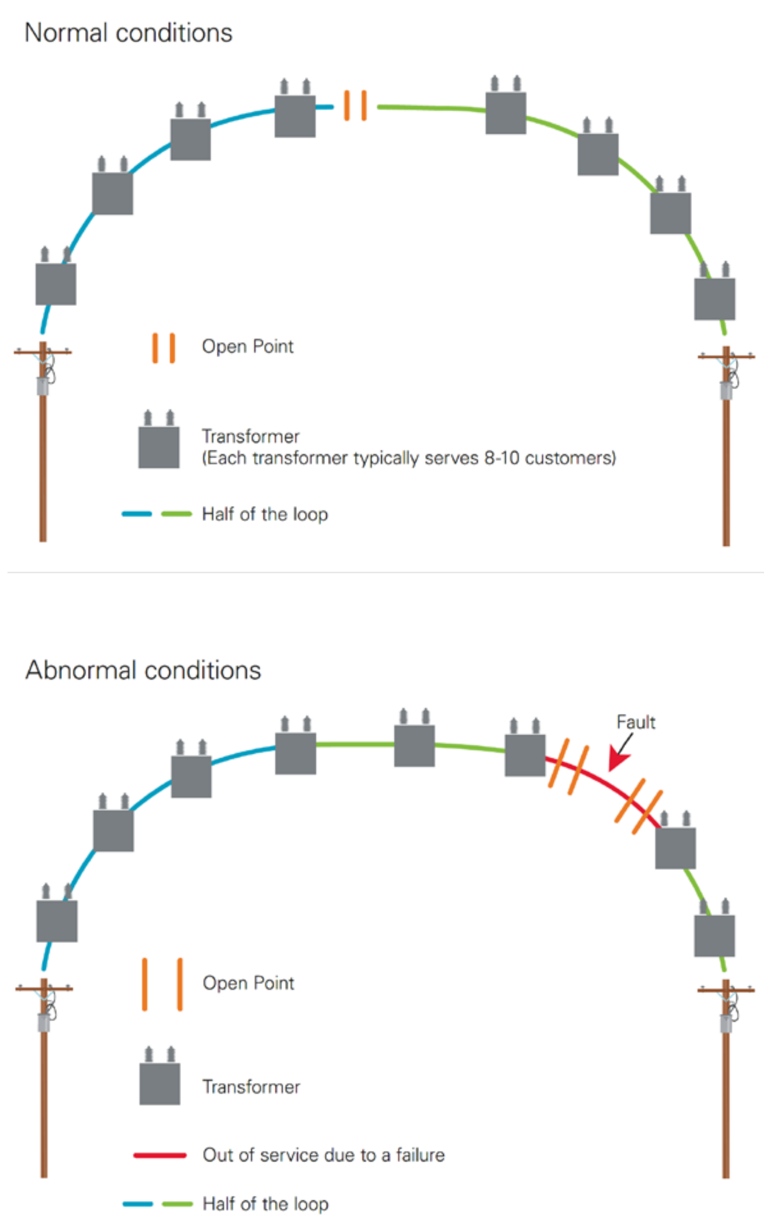
Q. HOW WILL THESE PROACTIVE CABLE REPLACEMENTS BENEFIT CUSTOMERS?

A. Currently, we typically repair cable after its first failure but then replace cable after its second failure in a two year period. By proactively replacing cable that has already failed once, we are able to replace this cable before it fails again and is unrepairable, leading to an emergency replacement. Emergency replacements leave the system with less redundancy and switching options, which can lead to lengthy outages when additional failures occur.

Another area for proactive replacement is in our URD system where we typically make segment replacements as particular sections fail. To the extent the budget allows, we intend to replace half loops on failed URD cables. In other words, we will be replacing not just the failed span but also the entire half loop or other spans of cable of the same vintage. This is depicted in Figure 11 below.

Figure 11

Underground Residential Distribution System



Q. HOW WILL PROACTIVELY REPLACING HALF LOOP URD CABLES BENEFIT CUSTOMERS?

A. Once a failure occurs on a segment, replacing the half loop of the segment benefits the customers on that entire loop by avoiding future failures of other segments. Because cable loops are of similar vintage and type of cable (they were installed at the same time originally), once repeated failures have occurred within that loop, it is only a matter of time before additional failures occur, both affecting customers' reliability and experience. The Company has had many cases where after the first three failures in a half loop, successive failures occur in more rapid succession as these cables are exposed to the same environmental and loading conditions. By replacing the half loop, instead of just segment replacement, the Company aims to avoid additional failures and outages for those customers. The Company also avoids customers experiencing such faults year over year by replacing cables all at once rather than in a piecemeal fashion.

c. Routine Rebuilds and Conversions

Q. DESCRIBE THE ROUTINE REBUILDS AND CONVERSIONS?

A. The bulk of this category is for smaller rebuild and conversion projects that occur during a given year. Rebuild projects include replacing poles due to public damage or minor storm damage. Conversion projects involve undergrounding overhead lines, generally at the request of customers or government entities (portions of these conversions may be paid for by the customer). Also included in this category are service renewals which are replacements of customer service laterals when these assets fail. The table below provides a summary of the actual, forecasted, and budgeted capital additions in Routine Rebuilds and Conversions from 2018 through 2024.

Table 15

2018-2024 Capital Additions –Rebuilds and Conversions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Routine Rebuilds and Conversions	$22.4	$29.8	$29.4	$31.0	$31.9	$33.3	$34.1

Q. HOW IS THE BUDGET FOR THE ROUTINE REBUILDS AND CONVERSIONS PROGRAM DEVELOPED?

A. The budget for this program is based on historical expenditure trends for this work. In recent years, we have seen an increase in reactive rebuilds for smaller projects like broken cross-arms or broken poles due to the age of our assets. This is the same trend that I discussed above related to our pole replacement program. This budget also reflects variation in the year-to-year investments in this category based on the unpredictable nature of both storms and public damage.

Q. PLEASE DISCUSS THE CAPITAL INVESTMENT TRENDS FOR ROUTINE REBUILDS AND CONVERSIONS FOR 2022 TO 2024.

A. Similar to what we have seen in our Pole Replacement program, we have been seeing more broken cross-arms and broken poles that require reactive replacements each year which has increased our budgets for this program as compared to historical actuals. Over the course of this multi-year rate plan, our capital budgets for Routine Rebuilds and Conversions is fairly flat with slight year-over-year increases related to inflation as well as increases to reflect additional reactive rebuild work.

d. Restoration/Failure Reserves

Q. DESCRIBE THE RESTORATION/FAILURE RESERVE BUDGET CATEGORY.

A. This category includes investments required to replace facilities that are damaged during storm events. Xcel Energy has a strong track record related to storm restoration and these investments are key to our ability to restore power quickly and safely after a severe weather event. Also, included in this budget category are reactive replacements of substation equipment that has failed and back-up transformers purchases that are needed to quickly address transformer failures throughout the system.

Q. CAN YOU PROVIDE A RECENT EXAMPLE OF THE COMPANY'S INDUSTRY-LEADING STORM RESPONSE?

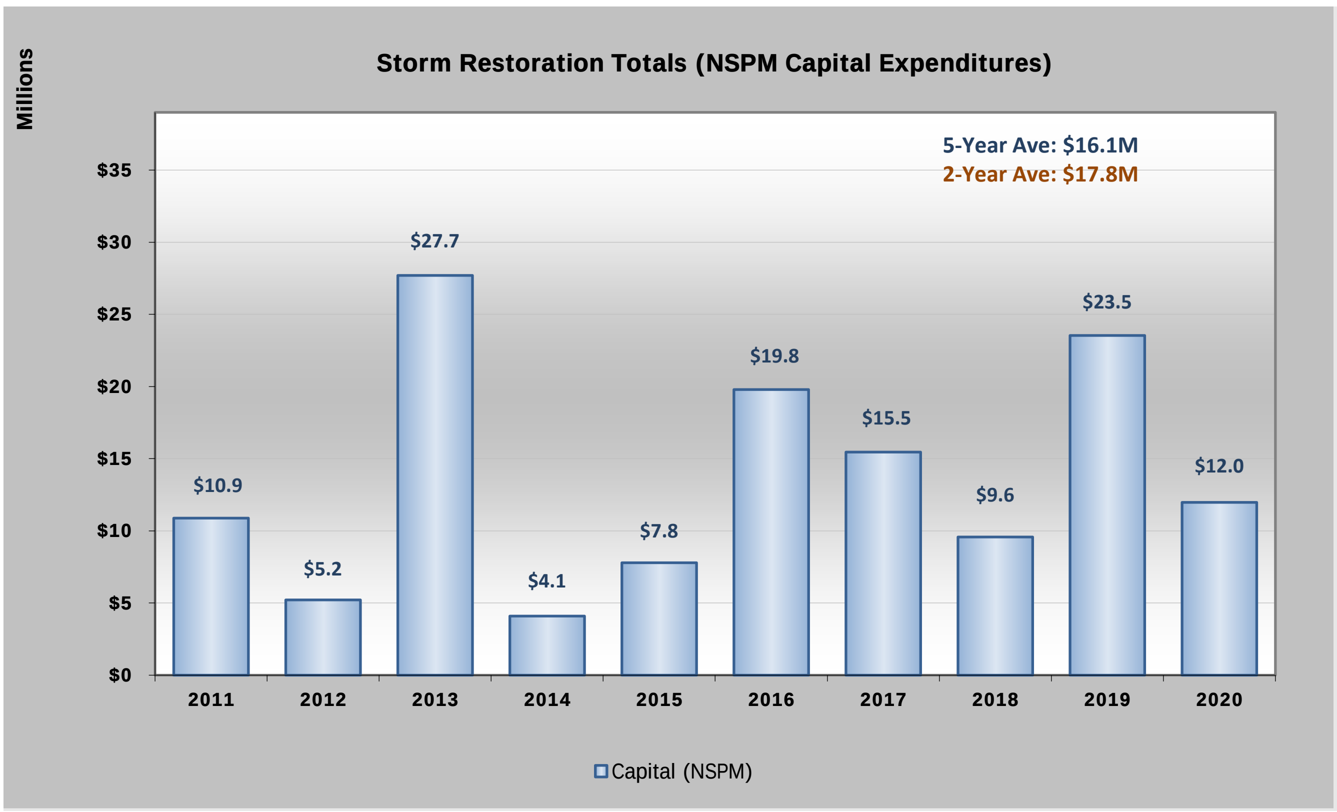
A. Yes. On September 16, 2021, a storm hit the Twin Cities area with winds over 75 miles per hour causing heavy damage to our distribution system. Our crews responded quickly and efficiently to bring electric service back to the over 120,000 customers that were impacted by this event. Despite the widespread and significant damage caused by this storm, Xcel Energy restored power to nearly 60 percent of impacted customers in eight hours or less.

Q. HOW IS THE BUDGET FOR THE RESTORATION/FAILURE RESERVE BUDGET CATEGORY DEVELOPED?

A. The majority of this budget is developed based on a review of the most recent five-year average for storm expense as well as the prior year's storm expense. As shown in Figure 12, the unpredictable nature of severe weather makes budgeting for storm challenging as there is no "typical" year for severe weather. This storm restoration budget is not assigned to a specific project or program. When there is a storm event, we reallocate budgeted dollars from the working capital budget to the affected project or program to address the specific need while remaining in balance with our overall annual capital budget. For the substation equipment component of this budget, we examine historical failure rates for substation equipment and add annual inflationary increases.

Figure 12

Historical NSPM Storm Capital Expenditures



Q. PLEASE PROVIDE AN OVERVIEW OF THE CAPITAL INVESTMENTS IN RESTORATION/FAILURE RESERVE FROM 2018-2024.

A. Table 16 below provides historical actuals, forecast, and budget for our Restoration/Failure Reserve program from 2018 through 2024.

Table 16

2018-2024 Capital Additions –Restoration/Failure Reserves

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Restoration/Failure Reserves	$10.5	$8.9	$25.8	$11.4	$26.3	$26.8	$26.6

Q. WHY IS THE 2022-2024 BUDGET FOR RESTORATION/FAILURE RESERVE HIGHER THAN PRIOR YEARS?

A. As I noted, we base a portion of this budget on the most recent five-year average of actual storm expense. As depicted in Figure 12 above, our most recent five-year average for storm expense is higher than prior years due to higher than average storm expenses in 2016 and 2019. This is leading to an increase in our budget for 2022-2024 as we want to ensure that we have adequate funding to address storm restoration based on historical trends.

Q. HOW IS THE FAILURE RESERVE BUDGET TRENDING OVER THE TERM OF THIS MULTI-YEAR RATE PLAN?

A. As shown in the table above, our investments in this budget category are expected to remain steady over the course of the multi-year rate plan. As I noted, since the majority of the capital additions in this budget category relate to storm restoration, there can be budget variations between years based on the severity and frequency of actual storm events. There are also fluctuations in capital additions from year to year based on the timing of in-servicing for substation reserve transformers.

e. Line Renewal Program

Q. WHAT TYPES OF CAPITAL INVESTMENTS ARE INCLUDED IN THE LINE RENEWAL PROGRAM?

A. Our Line Renewal program includes multiple subprograms that are targeted at replacing aging or poor performing components of our overhead mainline and feeder lines as well as our network assets to improve the reliability and resiliency of this portion of the system. These assets include cutouts, reclosers, cross-arms, braces, insulators, feeders, vault tops, transformers, and arrestors. Also included in this budget category are improvements required for our mainline and feeders to better support the interconnection of DER.

Q. HOW IS THE BUDGET FOR THE LINE RENEWAL PROGRAM DEVELOPED?

A. The budget for the Line Renewal program is based on a summation of all the budgets for each of the individual subprograms that comprise this program. For those programs that address reactive replacements, these budgets were developed based on historical trends and failure rates. For programs that address proactive replacements, we developed these budgets based on the particular work that is planned for these programs during the multi-year rate plan. For instance, for the CSG Recloser program, we developed the budget based on the labor and material costs required to install approximately 250 reclosers in 2022. This program is discussed in more detail below. The table below provides a summary of the actual, forecasted, and budgeted capital additions for the Line Renewal program from 2018 through 2024.

Table 17

2018-2024 Capital Additions – Line Renewal Program

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Line Renewal Program	$2.6	$9.7	$1.8	$7.9	$25.6	$13.7	$24.4

Q. WHY ARE THE BUDGETED CAPITAL ADDITIONS IN THE LINE RENEWAL PROGRAM FOR 2022-2024 HIGHER THAN PRIOR YEARS?

A. During the term of this MYRP, Distribution will be commencing several new subprograms within the Line Renewal program to address aging equipment, reliability issues, and to better support DER interconnection. These new programs include the Community Solar Garden (CSG) Recloser program, the Porcelain Cutout Replacement program, the Southeast Region Reliability Initiative, the Pole Top Reinforcement program, Arrestor Replacement, and ELR Reclosers. The majority of these new programs are targeted to address issues with existing equipment on our overhead and network system that are impacting the reliability and resiliency of our service. For instance, in 2022, we will be starting a Porcelain Cutout Replacement program. This program will replace porcelain cutouts with polymer cutouts because porcelain cutouts have been failing at an increased rate due to material issues. This program is aimed at reducing outages caused by these legacy porcelain cutouts. In total, there is more than $40 million in capital additions attributed to these new programs in 2022-2024. I describe each of these programs below and provide support for how the budgets of these programs were developed. The table below provides a summary of all of the subprograms within the Line Renewal program and the 2022-2024 budgets for these programs.

Table 18

2022-2024 Capital Additions – Line Renewal Program

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Line Renewal Programs			
CSG Recloser Program	$15.3	$0.0	$0.0
Porcelain Cutout Replacement	$1.4	$3.2	$4.3
Southeast Region Reliability Initiative	$2.2	$2.7	$2.9
Feeder Performance Improvement Program	$2.0	$2.0	$2.1
ELR Network Vault Tops	$1.5	$1.7	$2.3
Pole Top Reinforcement	$0.0	$0.0	$4.3
ELR Network Protectors	$0.9	$1.0	$1.3
ELR Network Transformers	$0.5	$0.9	$1.6
Arrestor Replacement	$0.6	$0.7	$1.0
LED Post Top Conversion	$0.8	$1.0	$1.0
Reliability Management System (REMS)	$0.5	$0.5	$0.5
ELR Reclosers	$0.0	$0.0	$1.4
Other (<$1M/year)	$0.0	$0.0	$1.8
Total	**$25.6**	**$13.7**	**$24.4**

Q. WHAT IS THE CSG RECLOSER PROGRAM?

A. This is a new program in response to the Commission's May 26, 2021 Order requiring the Company to propose a plan to reduce the frequency and duration of planned outages that require CSGs to be disconnected from the system and to carry out the proposed plan by no later than June 1, 2022.[7] In response to this Commission directive, the Company submitted a plan on September 21, 2021 to install electronic reclosers on all existing CSGs.[8] The installation of these reclosers will minimize the impacts to CSGs during planned outages.

[7] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of its Proposed Community Solar Garden*, Docket No. E002/M-13-867, ORDER DIRECTING XCEL TO DEVELOP PROPOSALS (May 26, 2021).

[8] *In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of its Proposed Community Solar Garden*, Docket No. E002/M-13-867, COMPLIANCE-COMMUNITY SOLAR GARDEN PLANNED OUTAGES (September 1, 2021).

These reclosers will also provide safety benefits for Xcel Energy workers. For instance, these reclosers are effective at mitigating voltage and arc flash energy and will allow the Company to reduce the safety risk through engineering controls. This program will install electronic reclosers on both new and legacy CSGs to minimize the impact of planned outages on CSGs during hotline work. In its September 1, 2021 filing, the Company requested that the Commission approve a December 31, 2022 target completion date for installation of these reclosers. This program has $15.3 million in planned capital additions in 2022.

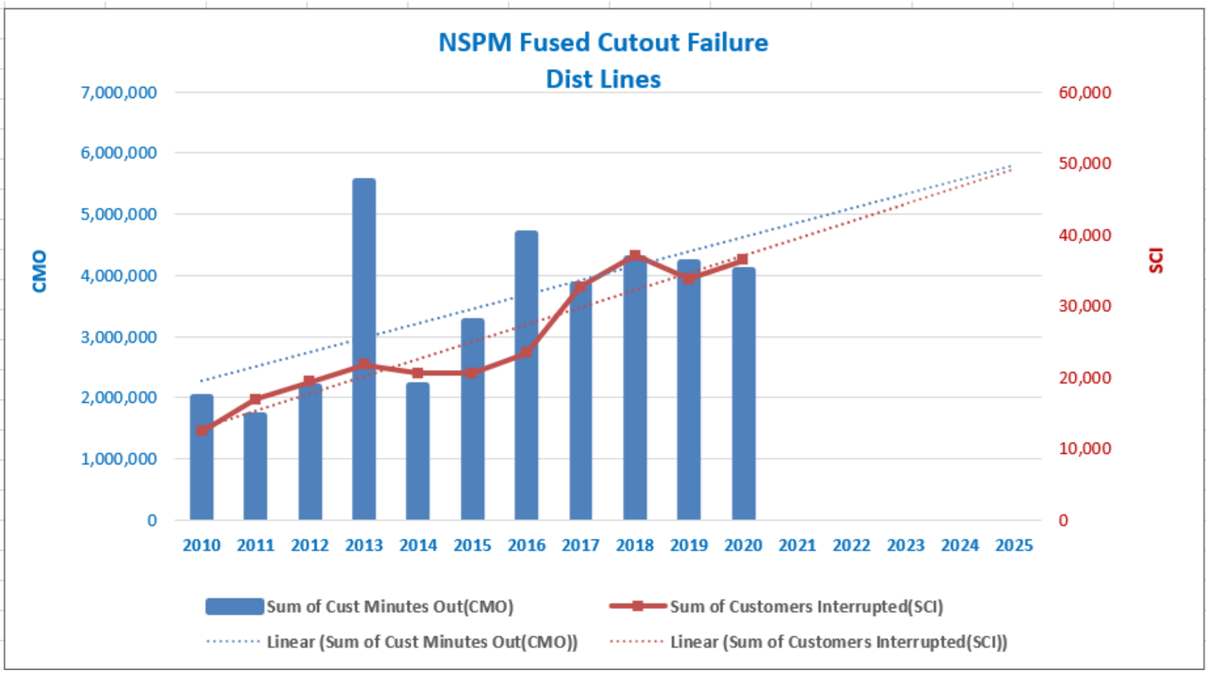
Q. PLEASE DESCRIBE THE PORCELAIN CUTOUT REPLACEMENT PROGRAM.

A. This is a new program starting in 2022 that is focused on replacing porcelain cutouts with polymer cutouts on overhead feeders. Cutouts are a mounting device for holding a protective fuse and are used to provide overcurrent protection on overhead feeders. Significant porcelain cutout quality issues emerged across the utility industry in the late 2000s. Porcelain cutouts develop small cracks that collect water that then freezes leading to fractures and then failure. Porcelain cutout failures are an issue because, while they can occur at any time, they frequently occur when a fuse is closed back in. This type of failure can then cause or extend the length of the outage for any customers served by the failed equipment. Additionally, when a porcelain cutout does fail, it can damage other equipment on the feeder and can be a safety concern.

As a result, Xcel Energy and many other utilities switched to installing polymer cutouts in the 2010s for new installations. As compared to porcelain, polymer cutouts have better cold weather reliability, are more durable during transit and installation, and have superior mechanical toughness. However, NSPM still has over 100,000 porcelain cutouts on its system and these porcelain cutouts have been experiencing an increasing rate of premature failures in recent years, averaging approximately 750 failures each year. The figure below shows the total impact that these failed cutouts have on CMO per year and on the number of customers interrupted each year. As this figure shows, in recent years, cutout failures have impacted a greater number of customers and have contributed to more CMOs as compared to 2010-2012.

Figure 13

Reliability Impact of Cutout Failures



This increasing failure rate is the main driver for this new program to replace the legacy porcelain cutouts on the system. We have budgeted $8.9 million in capital additions from 2022 through 2024 to replace approximately 12,000 porcelain cutouts on tap and riser poles as cutout failures on this portion of the system impacts the greatest number of customers. This budget is based on an estimated replacement cost per location and the number of cutouts that we plan to replace each year. We expect that replacement of porcelain cutouts on tap and riser poles will continue through at least 2026.

Q. DESCRIBE THE SOUTHEAST REGION RELIABILITY INITIATIVE.

A. Each year, the Company files an Annual Report and Petition on Service Quality Performance and Proposed Reliability Measures (Annual Service Quality Report). In the Company's 2018 Annual Service Quality Report, Docket No. E-002/M-19-261, the Commission raised concerns related to the reliability performance in the Company's Southeast Work Center which includes Winona, Red Wing, Mankato, and Lake Crystal. In its January 28, 2020 Order in the above referenced docket, the Commission required the Company to report on various issues related to reliability in the Southeast Work Center by February 27, 2020. In that report, the Company proposed to provide the Commission quarterly updates on the reliability metrics in the Southeast Work Center to keep the Commission informed on both our efforts and the outcomes of our work on this important issue. In its December 18, 2020 Order in the 2019 Annual Service Quality Report, Docket No E002/M-20-406, the Commission ordered the Company to continue filing quarterly status reports on efforts to improve reliability in the Southeast Work Center through fourth quarter 2021. The Southeast Region Reliability Initiative program is aimed at improving the reliability of this area by rebuilding poorly performing feeders in this area, by replacing porcelain cut-outs with polymer cutouts, and identifying and addressing other reliability challenges. This program has $7.8 million in planned capital additions from 2022 through 2024.

Q. DESCRIBE THE FEEDER PERFORMANCE IMPROVEMENT PROGRAM.

A. This program addresses reliability challenges in specific geographic areas that have lower than average service quality performance with targeted upgrades, such as rebuilds of overhead feeders and improvements to feeder protection schemes. Feeders are identified and evaluated for inclusion in this program using reliability data such as SAIDI (duration-based reliability metric), and SAIFI (frequency-based reliability metric), CMO, and the number of years the feeder has been on the list. The budget for this program is based on the number of feeders that are targeted to be rebuilt each year and the budget is prioritized to provide the greatest service benefit that can be achieved using available resources. This program has $6.1 million in planned capital additions from 2022 through 2024.

Q. DESCRIBE THE POLE TOP REINFORCEMENT PROGRAM.

A. This is a new program starting in 2024 that that will identify and replace pole top equipment and poles (due to pole top degradation versus ground line inspection in our pole replacement program) that have reached the end of their useful life. Pole top equipment includes cross-arms, braces, and insulators. Pole top issues include degraded cross-arms, degraded pole tops, loose guy wires, and cracked cutouts. As discussed earlier, NSPM has a number of poles 60 years old or older. With this advanced age, many of these pole tops, like the poles themselves, are in poor condition.

Pole top equipment that is poor condition is a major contributor to outages and storm related interruptions. Replacing this damaged equipment will harden the system and improve system performance especially during high wind conditions, icing, and heavy snow. Replacements of some pole top equipment is currently being done as part of our pole replacement program. However, this program will be broader in scope and will replace pole top equipment based on condition, performance history, vintage, and other factors. This program has $4.3 million in planned capital additions in 2024. It is important to note that with approximately 500,000 poles on the NSPM system, this program is expected grow and to continue for the foreseeable future.

Q. PLEASE DESCRIBE THE END-OF-LIFE VAULT TOP PROGRAM.

A. This program replaces vault tops that have reached their end of life resulting in potential tripping hazards to the public or safety issues for crews working within the vaults. We have approximately 179 vault tops in Minneapolis and approximately 83 in St. Paul that provide protection and access to our underground distribution network. This program has $5.5 million in planned capital additions from 2022 through 2024.

Q. PLEASE BRIEFLY DESCRIBE THE OTHER SMALLER SUBPROGRAMS WITHIN THE LINE RENEWAL PROGRAM.

A. Below is a brief description of the other subprograms within the Line Renewal program:

- *LED Post Top Conversion* – The Company has approximately 15,000 post top lights (decorative lighting) on the A30 (Street Lighting System Service) underground rate. Since 2019, the Company has converted about 8,000 of these lights to energy efficient LED and will continue to convert 2,000-4,000 per year until these lights are converted. The Company is converting these lights to LED lights for better public safety as these lights are a whiter light source that provides better visual clarity for both drivers and pedestrians. The LED lights last much longer than high pressure sodium lights (HPS) bulbs which means there is less maintenance needed and they are energy efficient so street lighting customers save 4 to 6 percent compared to the HPS lights. This program is different from our LED street light program, which is discussed in Section VI of my testimony, that was completed in 2019.

- *ELR Network Protectors-* This program replaces network protectors that have reached their end of life. The network protectors are required to provide electrical power to the downtown customers. These protectors provide the means to automatically connect and disconnect the power supply from transformers as required for system operation, faults, or maintenance. This program is established to replace the network protectors that are reaching the end of their useful life. There are approximately 700 network protectors on the downtown Minneapolis and St. Paul underground networks. The program replaces these devices at a frequency sufficient to maintain the health of the downtown electric network.
- *Arrestor Replacements-* This is a new program that will replace arrestors with a higher failure rates based on design and manufacturer. When these arresters fail they either cause a momentary outage or a sustained outage for the customers on the feeder. Failure of arrestors is one of the main outages on the overhead system. It is estimated that over 90 percent of the SAIDI impact from failed arrestors is from less than 30 percent of the arrestor population. The arrester replacement program will identify and replace these poor performing arresters on mainline and tap feeders to improve reliability for our customers.
- *ELR Network Transformers-* There are approximately 700 network transformers that are required to provide electrical power to the downtown customers. This program is established to replace the network transformers that are reaching the end of their useful life. The program

replaces these devices at a frequency sufficient to maintain the health of the downtown network.

- *Reliability Management System (REMS)-* This program is focused on improving reliability for customers that experience multiple electric service interruptions in a given year. The program reviews the service quality from a customer perspective and looks for ways to improve the reliability for these customers. Many times a starting point for these improvements is installing a fused cutout on the primary of the local transformer, replacing the arrestor at the local transformer, or installing a fused cutout on an unfused tap. In rare cases, these improvements can involve a larger project – rebuilding a tap to current standards, replacing the old existing copper wire with aluminum (stronger for tree branches falling on it), or installing taller poles to increase clearance.
- *ELR Reclosers-* This is a new program to replace reclosers on our overhead distribution lines that are reaching their end of life. Reclosers have an estimated useful life of approximately 30 years. Reclosers are automatic switches that automatically shuts off the flow of power when a fault is detected on the line. NSPM has approximately 2,000 reclosers. To maintain the quality of this equipment and minimize O&M expenditures on aging equipment, Distribution will replacing reclosers that are 30 years or older or near-end of life. Additional benefits of replacing this vintage equipment include potential communications and monitoring capability by using updated equipment, less required maintenance, and greater confidence in a device that supports both reliability and safety.

f. Substation Renewal Programs

Q. DESCRIBE THE SUBSTATION RENEWAL PROGRAMS.

A. These programs are focused on improving the reliability and resiliency of the Company's 242 substations in Minnesota through the replacement of key substation components. One of the main substation components is transformers. Substation transformers are fundamental to the reliability of our distribution system and are also one of the most expensive components of the substation. While the failure of transformers is not a common occurrence, when a substation transformer fails, the consequences are high as it often results in between 5,000 to 15,000 customers losing service. In addition to transformers, there are several other important components to a substation such as switches, breakers, relays, fences, and regulators that also must be maintained in working order.

These programs also includes investments to replace our mobile transformers that have reached the end of their life. Our mobile transformers are an essential asset that enables the Company to quickly restore power to customers when a substation transformer fails and a new permanent transformer must be installed (a process that can take several weeks).

Q. HOW ARE THE BUDGETS FOR THE SUBSTATION RENEWAL PROGRAMS DEVELOPED?

A. We select and prioritize the replacement of these substation components using several factors, including the age and condition of equipment, amount and type of load served, system reliability, and future load growth. As discussed below, starting in 2022, we need to increase the budgets for several of our substation renewal programs to address the age and condition of a number of our substation components. More specifically, we are increasing our Substation Renewal budget to replace these assets closer to their anticipated service life. For example, the average useful life of a substation transformers is around 55 years. Beyond 55 years, transformers experience higher degradation, lower reliability, and increased failures. The NSPM distribution system currently has over 500 substation transformers, and approximately 104 of these transformers are 50 years old or older and another approximately 101 transformers that are between 40-49 years old. In addition, we are also increasing funding to replace our breakers and relaying equipment when this equipment fails because replacement parts are no longer available to repair these assets due to their age. For example, the NSPM distribution system has over 300 substation breakers that are 50 years old or older. The table below provides a summary of the actual, forecasted, and budgeted capital additions for the Substation Renewal programs from 2018 through 2024.

Table 19

Substation Renewal Programs

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Substation Renewal Programs	$5.8	$3.2	$2.0	$3.3	$19.1	$23.2	$24.2

Q. HOW DO THESE INVESTMENTS BREAK DOWN INTO THE DIFFERENT SUBSTATION RENEWAL PROGRAMS DURING THE TERM OF THIS MYRP?

A. The table below provides a breakdown of the budget by program for 2022-2024. I discuss each of these programs below and provide support for each program’s budget including the increases that are projected over the term of this MYRP.

Table 20

2022-2024 Capital Additions – Substation Renewal Programs

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Substation Renewal Programs			
ELR Transformers	$5.8	$7.6	$7.9
ELR Switches	$5.6	$7.4	$7.7
ELR Breakers	$2.7	$3.2	$3.4
ELR Regulators	$1.7	$2.2	$2.3
ELR Mobile Substations	$2.5	$1.9	$2.0
ELR Batteries, Fences, Remote Terminal Units	$0.8	$0.9	$0.9
Total	**$19.1**	**$23.2**	**$24.2**

Q. DESCRIBE THE ELR TRANSFORMER PROGRAM.

A. This program proactively replaces high failure risk transformers that have reached their expected service life which is typically 55 years. During the term of this MYRP, Distribution plans to replace more transformers each year to replace those transformers that are beyond their expected life. As I mentioned, the NSPM distribution system currently has approximately 104 transformers that are 50 years old or older and another 101 that are between 40-49 years old. Based solely on the age of the transformers on the system, Distribution determined that replacing transformers that reach 55 years of age would require replacing an average of 10 transformers each year for at least ten years. Each transformer replacement costs approximately $1.5 million, so replacing 10 transformers each year amounts to $15 million per year. As shown in Table 20 above, our budget for our ELR Transformer program is below this targeted amount but Distribution is anticipating that budgets will increase over time to better align with the lifecycle of these assets.

It is important to note that to determine which of these aging transformers need to be replaced each year, we look not just at the age of the transformer but we also take into account manufacture/industry recommendation, maintenance cost, reliability concerns. Distribution also performs a dissolved gas analysis (DGA) of oil samples from transformers to help identify early signs of outgassing or internal degradation concerns.

Q. DESCRIBE THE ELR SUBSTATION SWITCH PROGRAM.

A. This program replaces switches inside the substation that have reached the end of their life and are too costly to repair. Our ELR switch program budget is increasing to proactively replace these switches closer to their life expectancy and minimize failures. Switches are inspected regularly and need to operate reliably when called upon to either provide circuit isolation or line transfer. Any switches that are identified as not performing as intended or that are damaged are added to the proactive replacement portfolio and appropriately budgeted. Additionally, we also evaluate switches that have surpassed their 50-year life expectancy or that have manufacturer design issues, and then these switches may be added to the proactive replacement plan based on our assessment. Currently, there are 9,675 switches installed in the NSPM distribution system. Using the estimated life expectancy of 50 years, we will need to replace an average of 194 units each year to lower the age of switches on the system. Assuming an average unit replacement cost of $50,000, an annual budget of $9.7 million per year would be required to replace switches when then reach their average life expectancy. As shown in Table 20 above, our annual budgets for our ELR Substation Switch program during the MYRP are below this targeted amount but Distribution is anticipating that budgets will increase over time to better align with the lifecycle of these assets.

Q. DESCRIBE THE ELR SUBSTATION BREAKERS PROGRAM.

A. Currently, there are 1,495 substation breakers installed in the NSPM distribution system and over 300 of these are 50 years old or older. This program replaces breakers that have reached the end of their life, which is typically around 50 years. This 50-year life expectancy is based on manufacture/industry recommendations, maintenance cost, reliability data, oil/gas leaks, and failure rates. Over the term of this MYRP, ELR substation program budget are increasing to proactively replace breakers closer to their life expectancy and minimize failures. Using the 50 year estimated life expectancy, Xcel Energy will need to replace 30 units each year over at least the next 10 years to replace breakers that are at or older than 50 years. Assuming an average unit replacement cost of $170,000, an annual budget of $5 million per year would be required to replace breakers when then reach their average life expectancy. As shown in Table 20 above, our annual budgets for our ELR Substation breaker program during the MYRP are below this targeted amount but Distribution is anticipating that budgets will increase over time to better align with the lifecycle of these assets. As noted above, we are also increasing the budget for breakers to account for the fact that replacement parts are no longer available so more repairing assets is no longer in option in most cases.

Q. DESCRIBE THE ELR REGULATOR PROGRAM.

A. This program replaces substation voltage regulators that have reached the end of their life, which is typically around 40 years. Over the term of this MYRP, Distribution is increasing the ELR regulator program budget to proactively replace breakers closer to their 40-year life expectancy and minimize failures. The life expectancy for regulators is based on manufacture/industry recommendation, maintenance cost, and reliability. DGA oil samples from regulators are also monitored for any signs of long-term concerns on the equipment and taken into account when generating the budget need. Currently, there are 603 regulators installed in the NSPM distribution system. A minimum of 15 regulators will need to be replaced starting in 2022 to replace each regulator that is 40 years old or older. Assuming an average unit replacement cost of $150,000, an annual budget of $2.3 million per year is required to replace regulators when then reach their average life expectancy.

Q. DESCRIBE THE ELR MOBILE SUBSTATION PROGRAM.

A. This program replaces mobile substations that have reached the end of their life. Mobile substations are large, trailer-based equipment designed to temporarily provide power during an emergency outage or provide support for construction and maintenance projects to allow for safe, de-energized working conditions while maintaining electric service to our customers. Mobile substations are stored at various locations throughout our service territory for use during transformer failures, to permit safe construction or maintenance, and occasionally for load relief. These mobile substations can be installed in less than 24 hours.

Q. WHY IS ADDITIONAL FUNDING NEEDED FOR MOBILE SUBSTATIONS OVER THE TERM OF THE MYRP?

A. Xcel Energy currently has a mobile substation fleet of 14 substation units and three mobile transformers across the NSP System. Eleven of these units are beyond the typical operating lifespan of 50 years (52-73 years) and are experiencing more frequent maintenance and therefore reduced reliability. For 2022-2024, we have budgeted to purchase one to two mobile substations units each year to begin renewing of the existing fleet of these key assets. We plan to continue this refreshment of our mobile substation fleet after the term of this MYRP.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHEN A MOBILE SUBSTATION WAS DEPLOYED TO REDUCE OUTAGE TIMES FOR CUSTOMERS?

A. Yes. On July 28, 2020, the City of Eagle Lake near Mankato Minnesota, experienced an extended outage due to a substation transformer failure. The failure occurred during the day and with the support of solar distributed generation on the feeder, we were able switch to an alternate source and restore power to the 1,370 customers after 2 hours and 46 minutes. However, the alternate source was not able to support the peak load when the solar distributed generation was offline. To ensure uninterrupted power when the solar distributed generation was offline, a mobile substation was installed overnight and the load, and generation was transferred to the mobile substation. This mobile substation was used for 60 days until a replacement transformer was obtained and installed.

g. Discrete Asset Health Projects

Q. WHAT IS INCLUDED IN THE DISCRETE ASSET HEALTH BUDGET CATEGORY?

A. This budget category includes specific larger projects related to the replacement of aging infrastructure and/or reliability-focused projects. These projects are called out as discrete projects due to the size of the associated capital investments as well as the larger scope of the project.

Q. HOW IS THE BUDGET FOR THIS CATEGORY DETERMINED?

A. The budget for this category is based on discrete asset health projects that are planned for each year. These discrete projects are identified based on the age, condition, or reliability issues related to a particular feeder or a substation.

Q. WHY ARE THE CAPITAL INVESTMENTS FOR DISCRETE PROJECTS INCREASING STARTING IN 2022 AND CONTINUING THROUGH 2023?

A. This increase in capital investments is the result of several larger rebuild projects that will have plant additions in these years. These projects, which I discuss in greater detail below, involving rebuilding distribution lines and substations in several communities.

Q. WHAT KEY DISCRETE ASSET HEALTH AND RELIABILITY PROJECTS WILL DISTRIBUTION UNDERTAKE DURING 2022 TO 2024?

A. There are five key discrete Asset Health and Reliability projects that the Company will undertake during these years: (1) Dayton's Bluff Substation Reinforcement Project; (2) Rebuild Downtown St. Paul Manholes Project; (3) West St. Cloud to Millwood Rebuild Project; (4) Gaiter Lake Substation Project; and (5) Conversion of Butterfield 4 kV Project.

Q. DESCRIBE THE DAYTON'S BLUFF SUBSTATION REINFORCEMENT PROJECT.

A. This project involves rebuilding the existing 115/13.8 kV Dayton's Bluff Substation located in St. Paul, Minnesota. The substation is being rebuilt due to the age and condition of the existing substation. The existing transformers at this substation along with other components are reaching their end of life and need to be replaced to maintain the reliability of this substation. This project involves the replacement and installation of three 115/13.8 kV 50 MVA transformers, as well as the replacement and reconfiguration of the feeders within the substation. The Dayton's Bluff Reinforcement Project will be constructed starting in 2022 and will be placed in service in 2024. This project has a total plant addition of $20.3 million.

Q. DESCRIBE THE REBUILD OF THE DOWNTOWN ST. PAUL MANHOLES PROJECT.

A. The Downtown St. Paul Manholes Project is a multi-year project that involves replacing the aging underground manholes and duct bank in downtown St. Paul. This project is being driven by the planned road rebuilds in downtown St. Paul. The City of St. Paul has a moratorium that prevents utilities from doing work under a road for five years after the completion of a road rebuild project. The Company assessed the manholes and duct bank in the affected roads, and determined that those assets would need to be replaced within the next five years due to age and condition. Therefore, the Company has budgeted for the replacement of the affected manholes and duct bank to align with the timing of the City's planned rebuild work. The project has total plant additions of $9.5 million.

Q. DESCRIBE THE WEST ST. CLOUD TO MILLWOOD REBUILD PROJECT.

A. This project involves the rebuilding of the distribution feeder that is underbuilt on the West St. Cloud – Millwood 69 kV transmission line. The transmission line is being rebuilt due to the age and condition of the existing line. When the transmission line is rebuilt, the distribution underbuild located on the transmission poles will need to be rebuilt as well. Approximately 21 miles of distribution line is being replaced, affecting several different feeders. The voltages of the distribution lines are 4.16 kV, 12.47 kV, or 34.5 kV, depending on the feeder. These feeders are being rebuilt in three different phases over the course of three years starting in 2021, with the work schedule being driven by Transmission's work on rebuilding the 69 kV line. Phase 1 of this three year project is beginning in fall of 2021, phase 2 will begin in 2022, and phase three will begin in 2023. The West St. Cloud to Millwood Rebuild project is planned to be in service in 2023 with a total plant addition of $5.5 million.

Q. DESCRIBE THE GAITER LAKE SUBSTATION PROJECT.

A. This project involves the construction of a new substation called Gaiter Lake, located south of Waseca, Minnesota. The new substation will be a (69 kV/23.9 kV) single 7 MVA transformer with two feeders picking up load from the Clarks Grove, Meridan, and Waseca substations. The new Gaiter Lake Substation will allow the Company the ability to retire the Clarks Grove and Meridian substations. Also, this project will help address reliability concerns on all three feeders involved. With the increase in the capacity of the Clarks Grove Substation, we will help alleviate potential overload conditions on the feeders from the Waseca and Clarks Grove substations under certain contingencies. The project is currently in the planning phase and will move to the design phase in early 2022 with a planned in service in 2025. This project has capital additions of $3.8 million over the term of this multi-year rate case.

2. New Business

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE NEW BUSINESS CATEGORY?

A. Projects in this category are related to extending electric service to new customers or to support increased loads from existing customers. To serve a new customer, we must generally, at a minimum, extend our distribution system from the nearest practical point and install a transformer, a service extension, and meter(s). Our capital investments in this category include installation or expansion of feeders, primary and secondary extensions, service laterals, transformers, meters, and street lights. Table 21 provides a breakdown of the planned capital additions in the New Business category for 2022 through 2024.

Table 21
2022-2024 Capital Additions – New Business
(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Extensions / New Services	$35.95	$36.23	$37.20
Transformer Purchases	$19.29	$20.54	$20.88
Meter Purchases	$4.51	$3.89	$2.77
Street Lighting	$0.80	$0.60	$0.62
Total	**$60.5**	**$61.3**	**$61.5**

Q. HOW IS THE BUDGET FOR NEW BUSINESS DEVELOPED?

A. Our budget for New Business is driven primarily by economic growth. New business budgets are based on meter set forecast and estimated cost-per-meter. Meter growth rates are based on the Company's forecasted customer growth rates. Company witness Mr. John Goodenough discusses the Company's forecasted customer growth rates for the multi-year rate plan in greater detail. As explained by Mr. Goodenough, as the economy begins to recover we expect to see new customer growth beginning in 2022. This growth is expected to carry into 2023 and 2024 as the expected economy recovery continues. As a result, we expect our investments in New Business to increase slightly from 2022 through 2024. However, I note that economic conditions impact our new business investments and the economic recovery may not be as quick as we project, or another economic downturn could also occur. These circumstances would reduce our anticipated investments, while a faster than anticipated economic recovery could increase our New Business capital additions.

Q. PLEASE DESCRIBE THE COMPANY'S PLANNED CAPITAL ADDITIONS RELATED TO EXTENSIONS AND NEW SERVICE DURING THE TERM OF THE MYRP.

A. New housing growth and new commercial developments necessitate construction of new overhead and underground line extensions, transformers, service laterals, and meters to serve these new customers. In recent years, extensions and requests for new service have remained steady despite the COVID-19 pandemic.

Q. PLEASE DESCRIBE THE COMPANY'S PLANNED CAPITAL INVESTMENTS RELATED TO TRANSFORMERS DURING THE TERM OF THE MYRP.

A. The transformers category includes the purchase and installation costs of any distribution service transformer and voltage regulator necessary to serve new or existing customers. Transformer purchases are primarily needed to serve new customers. However, transformer purchases are also needed to serve increased customer load, or in the event an existing transformer fails, malfunctions, or reaches end of life.

Q. PLEASE DESCRIBE THE COMPANY'S PLANNED CAPITAL INVESTMENTS RELATED TO METERS DURING THE TERM OF THE MYRP.

A. The meters category includes the purchase and installation costs of distribution meters necessary to serve new or existing customers. Meter purchases are primarily for new customers in order to measure demand and energy at the point of delivery. Existing meters in some instances require replacement due to increased customer demand, load, or in the event an existing meter fails or malfunctions. This category does not include the installation of AMI meters that are being installed starting in 2022 as part of the AGIS initiative. The rollout of the new AMI meters will result in fewer meter purchases from 2022 through 2024 as these AMI meters will be new and less likely to fail or malfunction. While AMI meters are being deployed, we may still need to replace an failed meter with non-AMI meter if the meter is located in an area where FAN has not yet been deployed.

Q. PLEASE DESCRIBE DISTRIBUTION'S PLANNED CAPITAL INVESTMENTS RELATED TO STREET LIGHTING DURING THE TERM OF THE MYRP.

A. The street lighting category includes any new street or area lights placed into service, and we expect that this category will have only a minimal amount of investment from 2022 through 2024.

3. Capacity

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE CAPACITY CATEGORY?

A. Our Capacity investments include projects associated with upgrading or increasing capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers. Our Capacity projects include large discrete projects which typically involve construction of new substations, or upgrading transformers at existing substations. We also have two Capacity programs – Grid Reinforcement and Feeder Load Monitoring. The Grid Reinforcement Program is a new program that will start in 2022 and will be focused on ensuring that our distribution equipment and facilities are able to handle increasing load, including from EVs and other electrification. Our

Capacity investments also include routine capacity reinforcements which are investments that are required each year to address system issues such as overloads or contingencies that are caused by system load growth. Table 22 provides a breakdown of the capital additions budget for Capacity projects for 2022 through 2024.

Table 22

2022-2024 Capital Additions – Capacity

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	**2022 Budget**	**2023 Budget**	**2024 Budget**
Discrete Capacity Projects	$22.65	$28.00	$35.73
Grid Reinforcement Program	$1.60	$3.49	$6.99
Feeder Load Monitoring Program	$5.97	$6.61	$6.81
Routine Capacity Reinforcements	$2.96	$3.34	$3.43
Total	**$33.2**	**$41.4**	**$53.0**

Q. HOW DO YOU ESTABLISH THE BUDGET FOR CAPACITY PROJECTS?

A. To identify our discrete Capacity projects, Distribution capacity planners annually evaluate the peak loading on the substation transformers and feeders. Risks are identified, and solutions examined using a risk-versus-cost methodology. For the new projects and programs within this budget category, we based the budget on the specific scope of work planned during the term of the multi-year rate plan.

Q. WHAT IS DRIVING THE INCREASE IN CAPACITY INVESTMENTS FROM 2022 THROUGH 2024?

A. The increase in Capacity investments is driven by a couple of factors. First, we are investing the new Grid Reinforcement Program which will commence in

2022 and ramp up through 2024. The increase is also driven by eight discrete Capacity projects that the Company will undertake during the term of the MYRP with total capital additions of over $3 million. Six of these eight projects will be placed in service in 2024 which is why capital additions for 2024 are higher as compared to 2022 and 2023. I describe these eight discrete capacity projects as well as the other programs that comprise the Capacity category below.

Q. WHAT ARE THE EIGHT LARGE DISCRETE CAPACITY PROJECTS THAT THE COMPANY PLANS TO COMPLETE FROM 2022 THROUGH 2024?

A. These eight Capacity projects are: (1) Birch Area Substation Project; (2) Hyland Lake Substation Project; (3) Midtown Substation Project; (4) Pine Bend Substation Project; (5) Elm Creek Substation Project; (6) Baytown Feeder Project; (7) Kasson Substation Project; and (8) Tracy Switching Station Project.

Q. DESCRIBE THE BIRCH AREA SUBSTATION PROJECT.

A. This project involves the construction of a new substation, the Birch Area Substation, near White Bear Lake, Minnesota. This new substation is needed to mitigate contingency risks on nearby feeders due to the limited switching capability available in the area. As the nearby 34.5 kV substations have limited expansion capabilities, a new substation is need to mitigate these risks. This new Birch Area Substation will include a new 70 MVA 115/34.5 kV transformer and one new 34.5 kV feeder. This project is scheduled to be in service in 2024 with total plant additions of $7.5 million.

Q. DESCRIBE THE HYLAND LAKE SUBSTATION PROJECT.

A. This project is needed to mitigate two transformer contingency risks and two feeder risks at the existing 115/13.8 kV Hyland Lake Substation located in Bloomington, Minnesota. The project will also provide additional capacity to serve growing load in the area. The Hyland Lake Project involves the installing two new 70 MVA 115/13.8 kV transformers to replace the two existing 50 MVA transformers and construction of a new 1.5 mile 13.8 kV feeder. This project will be placed in service in 2023 with total plant additions of $7.5 million.

Q. DESCRIBE THE MIDTOWN SUBSTATION PROJECT.

A. This project is needed to mitigate a large transformer contingency risk at the existing 115/13.8 kV Midtown Substation located - near Oakland Avenue South and 29th Street in Minneapolis, Minnesota. This area of Minneapolis is one of the most culturally and economically diverse areas of the State. The project will provide additional capacity to serve existing load in the area, as well as providing capacity to accommodate future load growth. The Midtown Substation Project involves the installation of a new 70 MVA 115/13.8 kV transformer at the Midtown Substation. The project will be completed and placed in service in 2022 with total plant additions of $4.7 million.

Q. DESCRIBE THE PINE BEND SUBSTATION PROJECT.

A. This project intends to mitigate a large transformer contingency risk at the Rich Valley Substation in Inver Grove Heights, Minnesota. Due to space constraints at Rich Valley Substation, the existing transformer at the nearby Pine Bend substation will be replaced with a 13.8/115 kV 50 MVA transformer. Two new 13.8 kV feeders will be installed at Pine Bend that will provide additional capacity to Rich Valley. This project is currently planned to be in service in 2023 with total plant additions of $4.5 million.

Q. PLEASE DESCRIBE THE ELM CREEK SUBSTATION PROJECT.

A. This project is needed to mitigate overloads on one of the transformers at the existing 115/34.5 kV Elm Creek Substation located in Maple Grove, Minnesota. The project will also provide additional capacity to serve growing load in this area. The Elm Creek Substation Project involves the installation of a new 115/34.5 kV transformer in the Elm Creek Substation and a new 1.9 mile 34.5 kV feeder. The transformer portion of the Elm Creek Project is planned to be in service in 2021 and the feeder construction will be complete and placed in service in 2022. The total plant additions for the Elm Creek Project is $6.7 million.

Q. PLEASE DESCRIBE THE BAYTOWN FEEDER PROJECT.

A. This project is needed to mitigate contingency risks on the two 34.5 kV feeders extending from the Afton and Hugo substations located near Lake Elmo, Minnesota. This project involves the construction of two new 13.8 kV feeders extending from the Baytown Substation to transfer load from the overloaded 34.5 kV feeders to the new 13.8 kV feeders. This load transfer will increase available capacity on the Afton and Hugo 34.5 kV feeders to accommodate load growth. This project is currently planned to be in service in 2024 with total plant additions of $4.4 million.

Q. PLEASE DESCRIBE THE KASSON SUBSTATION PROJECT.

A. This project is needed to mitigate overloads on the transformers and feeders at the Kasson Substation. This project involves the replacement of the existing

69/12.47 kV 10 MVA transformer at the Kasson Substation with a larger 69/12.47 kV 28 MVA transformer. The project will also install a new 12.47 kV feeder from the Kasson Substation to provide capacity to serve existing load at both the Kasson Substation and the nearby West Byron Substation. Construction for this project will start at the end of this 2021 with a planned in service in 2022 and total plant additions of $3.4 million.

Q. PLEASE DESCRIBE THE TRACY SWITCHING STATION PROJECT.

A. This project is needed to mitigate overloads on the 69/13.8 kV substation transformer at the Tracy Switching Station located near Tracy, Minnesota. The project involves replacing the existing transformer at Tracy Switching Station as well as installing a new 13.8 kV feeder that will replace the existing 4 kV feeder from the Tracy Substation. This project will allow for the retirement of the 4 kV Tracy Substation. This project is currently planned to be in service in 2024 with total plant additions of $3.0 million.

Q. DESCRIBE THE GRID REINFORCEMENT PROGRAM.

A. This program involves making upgrades to our distribution system to enable the system to handle increased load associated with increased EV adoption as well as electrification of other sectors of the economy. In 2022-2024, this program will involve making upgrades to service transformers, poles, primary conductors, and secondary conductors. An example of a project that the Company plans to complete as part of this program is to replace undersized overhead transformers and undersized conductors that are currently 90 percent loaded. Adding load to these undersized transformers and conductors (i.e., adding a level 2 EV charger) could overload the transformer and cause outages. Proactively replacing these transformers and conductors, will enable flexibility in the grid to accommodate load growth and minimize reliability issues to customers.

Q. PLEASE DESCRIBE THE MINNESOTA FEEDER LOAD MONITORING PROGRAM

A. The purpose of the Feeder Load Monitoring program is to install SCADA at substations that have partial or no Feeder Load Monitoring (FLM). Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. This includes control and data of our system, and we frequently refer to the data acquisition portion as Feeder Load Monitoring or FLM. A substation that has SCADA almost always contains both FLM and control. However, there may be substations where we do not have FLM, but we do have control.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels for each substation over an entire year. This information is used as inputs to our Distribution planning process. Ideally we are able to collect all of these data points at each of our substations. However, not all of these data points are available for all substation locations. For internal tracking and reporting purposes, when all three-phase Amps, MW, MVar, and kV are included on all feeders, and two of the following three for the substation transformers (MW, MVar, or MVA) the substation is classified as "Full FLM." If we are missing one or more data points at the substation, then the substation is classified as "Partial FLM." If none of these data points are collected at a substation, the substation is classified as "No FLM." Currently, 33 percent of our Minnesota substations qualify as "No FLM," 20 percent qualify as "Partial FLM," and 47 percent qualify as "Full FLM."

Given the importance of SCADA capabilities to reliability and load monitoring (for planning and due to increasing levels of DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at three to five substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA. Starting in 2022, this program aims to complete the rollout of SCADA at most of the remaining substations in Minnesota. The Company has budgeted $19.4 million for the Minnesota Feeder Load Monitoring program over the term of this multi-year rate case ($6.0 million in 2022; $6.6 million in 2023; and $6.8 million in 2024).

Q. PLEASE DESCRIBE THE TYPES OF ROUTINE CAPACITY REINFORCEMENT PROJECTS THAT DISTRIBUTION WILL COMPLETE DURING THIS MYRP.

A. These projects are smaller, reactive Capacity projects that arise each year to address the need for additional capacity on certain portions of our system. These projects include replacing undersized transformers or conductors. The Company has budgeted $9.7 million for routine capacity reinforcements over the term of this multi-year rate case ($3.0 million in 2022; $3.3 million in 2023; and $3.4 million in 2024).

4. Mandates

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE MANDATES CATEGORY?

A. These are projects that involve relocating existing utility infrastructure to accommodate public projects such as road widening or realignment. Table 23 provides a summary of the capital additions budget for Mandate projects for 2022 to 2024.

Table 23

2022-2024 Capital Additions – Mandates

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022	2023	2024
Discrete Mandate Projects	$13.70	$14.52	$18.41
Routine Relocations	$13.75	$14.07	$14.42
Mandated Programs	$0.55	$0.63	$0.65
Total	**$28.0**	**$29.2**	**$33.5**

Q. HOW DOES DISTRIBUTION ESTABLISH THE BUDGET FOR MANDATES PROJECTS?

A. Mandate capital addition budgets are developed based on historical trends and known projects. The Company also coordinates with counties and cities within our service territory to ensure adequate funding for anticipated road work. Mandates tend to trend higher with a favorable economy as cities and counties have additional tax revenues for improvement projects such as road updates.

Q. PLEASE PROVIDE AN EXAMPLE OF A DISCRETE MANDATE PROJECT THAT THE COMPANY PLANS TO COMPLETE DURING THE TERM OF THIS MULTI-YEAR RATE PLAN.

A. An example of a mandate project is the Dayton's Bluff Relocation project. This project involves relocating multiple feeders and manholes that are in conflict with the City of St. Paul's Kellogg/3rd St. bridge project in downtown St. Paul. This project will be placed in service in 2022 with $4.2 million in capital additions. This project is separate from the Dayton's Bluff Substation Reinforcement Project that I discussed above in our Asset Health and Reliability category. That project involves replacing assets at the Dayton's Bluff Substation that have reached the end of their life.

Q. PLEASE DESCRIBE THE TYPES OF INVESTMENTS MADE AS PART OF ROUTINE RELOCATIONS.

A. These are smaller relocations of our equipment and facilities that are needed to accommodate smaller road projects, bridge projects, or bike trail projects by cities or counties.

Q. PLEASE DESCRIBE THE TYPES OF INVESTMENTS MADE AS PART OF MANDATED PROGRAMS.

A. These are primarily pole transfer projects that are required when our distribution equipment is located on another utilities' pole and that must be transferred to a new pole when that pole is replaced or relocated.

5. Tools and Equipment

Q. WHAT IS INCLUDED IN THE BUDGET FOR THE TOOLS AND EQUIPMENT CATEGORY?

A. This category includes various expenditure types required to support our overall operations, including capital tool and equipment purchases. One of the largest drivers in this category over the three-year term of this rate case is a planned fiber optic build-out that will allow the Company to reduce its dependency on third-party telecommunication providers and improve the reliability, performance, and cyber security of its communication network. Another driver is the communication components needed for our Feeder Load Monitoring program which adds SCADA to our feeders to allow the Company to monitor peak demand. I discussed the Feeder Load Monitoring project above as part of our Capacity investments. Table 24 provides a breakdown of the capital additions budget for Tools and Equipment projects for 2022 through 2024.

Table 24

2022-2024 Capital Additions - Tools and Equipment

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Tools & Equipment			
Fiber Buildout Program	$3.7	$4.6	$4.8
Routine Tools and Equipment	$2.9	$2.5	$2.3
Feeder Load Monitoring Program	$1.9	$2.2	$2.3
Network Monitoring Program	$1.7	$2.2	$2.2
Cyber Security Program	$1.6	$2.0	$2.3
Miscellaneous Tools and Equipment	$0.8	$0.5	$0.4
Total	**$12.6**	**$14.1**	**$14.3**

Q. DISCUSS THE INVESTMENTS IN FIBER OPTIC BUILDOUT THAT DISTRIBUTION WILL BE MAKING FROM 2022 THROUGH 2024.

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 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 data that we transmit within acceptable performance requirements for the teleprotection of our distribution 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.

As a result, from 2022 through 2024, Distribution will be installing upgraded telecommunication equipment and installing a private communication network path (fiber optic cable) from certain Distribution substation to a leased fiber optic cable that will be solely used only by the Company for communication within our network.

Q. WHAT INVESTMENTS WILL DISTRIBUTION BE MAKING IN ROUTINE TOOLS AND EQUIPMENT DURING THE TERM IN THE MYRP?

A. This category of investments includes all of the standard tools and equipment that are used by Distribution each year to complete our capital work. This includes tools like crimpers, presses, cutters, power tools, arc protection blankets, rock augers, chain hoists, gas and electric staplers, stringing equipment, and meter recording devices.

Q. PLEASE DESCRIBE THE NETWORK MONITORING PROGRAM.

A. The Network Monitoring program will enable remote monitoring and control of the network grids for downtown Minneapolis and St. Paul to ensure continuity of service, assess asset health, and improve operation and maintenance of these assets. The Network Monitoring system is comprised of transceivers and VaultGard devices that monitor and communicate the status of the downtown grid facilities along fiber optic cable installed concurrently with the network conductor. Installation of the Network Monitoring equipment will provide grid visibility and control utilizing real-time data from the downtown distribution networks that will enable the Company to:

- locate faulty equipment more quickly and accurately;
- identify distressed equipment prior to failure;

- identify system deficiencies and manufacturer issues on installed equipment;
- receive instantaneous, real-time email notifications of network events; and
- monitor the system on a real-time basis.

Q. DESCRIBE THE INVESTMENTS DISTRIBUTION PLANNING TO COMPLETE AS PART OF THE CYBERSECURITY PROGRAM DURING THE TERM OF THIS MULTI-YEAR RATE PLAN.

A. The objective of Distribution's Cybersecurity Program is to ensure compliance and on-going coordination with the corporate Enterprise Security & Emergency Management (ESEM) organization. This involves ensuring the safety and resiliency of the distribution system via the installation, monitoring, and maintenance of automated control equipment which support grid optimization practices supporting overall asset management and incident response planning activities. During this multi-year rate plan, we will be investing in a device management solution to ensure the security of key attributes of automated control equipment on the distribution grid (such as password protection and IP addresses).

6. Solar

Q. WHAT TYPES OF CAPITAL INVESTMENTS ARE INCLUDED IN THE SOLAR CATEGORY?

A. This category includes the distribution costs associated with interconnecting solar gardens to the distribution system as well as providing service extension to allow electric service for any auxiliary electric needs. The costs for these facilities are billed to the developer, and once payment is received a credit is applied to this budget category. As shown in Table 25, this is why no investments are budgeted for Solar projects for 2022 through 2024.

Table 25
2022-2024 Capital Additions - Solar
(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022	2023	2024
Solar	$0.0	$0.0	$0.0

7. AGIS

a. Overview of AGIS Investments

Q. WHAT IS AGIS?

A. The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future. The core components of AGIS are Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), the Field Area Network (FAN), and Fault Location, Isolation, and Service Restoration (FLISR).

Q. PLEASE BRIEFLY DESCRIBE EACH OF THESE FOUNDATIONAL COMPONENTS.

A. A brief description of these foundational components is as follows:

- *Advanced Distribution Management System (ADMS)* provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. The ADMS project includes investment to significantly improve the Company's existing Geospatial Information System (GIS), which is a foundational data repository, with data necessary to support the ADMS. ADMS uses this information to maintain the as-operated electrical model and advanced applications.

- *Advanced Meter Infrastructure (AMI)* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design.
- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, AMI, and the new intelligent field devices associated with advanced grid applications.
- *Fault Location Isolation and Service Restoration (FLISR)* involves software and automated switching devices as an additional component of the ADMS, that reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.

Q. HAS THE COMPANY PROPOSED ANY OF THESE AGIS INVESTMENTS TO THE COMMISSION?

A. Yes, the Company has received Commission certification of ADMS, AMI, and FAN. In the 2015 Biennial Grid Modernization Report, the Company sought certification of its proposed ADMS investments, which was subsequently certified by the Commission on June 28, 2016 for cost recovery under the TCR Rider.[9] In its 2019 Integrated Distribution Plan (IDP), the Company sought certification of AMI, FAN, FLISR, and IVVO and the Commission granted certification of AMI and FAN.[10]

Q. PLEASE DESCRIBE THE WORK THAT THE COMPANY HAS COMPLETED WITH REGARD TO THESE AGIS PROJECTS?

A. In 2020, the Company completed installation of the software and hardware components of ADMS and plans to enable ADMS at the three NSPM control centers by the end of 2021. In 2021, the Company began installing FLISR devices (reclosers, switches, and substation relays) on select feeders.

Q. PLEASE DESCRIBE THE WORK THAT THE COMPANY WILL BE PERFORMING ON THESE AGIS PROJECTS FROM 2022 THROUGH 2024?

A. From 2022 through 2024, Xcel Energy will be deploying approximately 1.4 million AMI meters throughout its service territory as well as deploying its FAN communication network in support of this meter deployment. The Company will also be continuing with installation of the FLISR devices during 2022

[9] *In the Matter of the Xcel Energy's 2015 Biennial Distribution Grid Modernization Report*, Docket No. E002/M-15-962, ORDER CERTIFYING ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. 216B.2425 AND REQUIRING DISTRIBUTION STUDY (June 28, 2016).

[10] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS (July 23, 2020).

through 2024 with installation expected to be completed by 2027. During this time period, the Company will also begin work on the final phase of the ADMS project which will include data collection, validation, and testing of feeders to support the additional advanced functionality of ADMS.

Q. WHAT TYPES OF CAPITAL INVESTMENT IS DISTRIBUTION MAKING TO IMPLEMENT THE AGIS INITIATIVE?

A. The capital investments that Distribution is making to implement each of the AGIS programs generally include material and equipment, labor, and vendor services.

Q. WHAT ARE THE DISTRIBUTION CAPITAL COSTS FOR THE AGIS INITIATIVE THAT THE COMPANY IS SEEKING RECOVERY OF IN THIS CASE?

A. The budgeted capital additions for AGIS-related investments from 2022 through 2024 are provided in Table 26 below. The Company proposes to recover of the Distribution capital costs associated with ADMS, AMI, and FAN via the TCR Rider through the term of the MYRP. Mr. Halama discusses the interplay between riders and base rates in his Direct Testimony. The only portion of the Distribution capital and O&M costs for ADMS, AMI, and FAN that will not be recovered in the TCR Rider is the portion attributed to internal labor, which is consistent with the Commission's decision in Docket No. E002/M-12-50. As such, internal labor will be recovered through base rates.

As the costs for FLISR were not previously certified by the Commission for inclusion in the TCR, the Company is proposing to recover the costs for FLISR in base rates. I provide additional information related to the Company's proposed deployment of FLISR below. Distribution's capital budget for 2023 and 2024 also reflects capital additions related to IVVO (0.2 million in 2023 and $3.7 million in 2024). However, Distribution does not plan to in service any portion of IVVO in 2023 or 2024. The Company will make the appropriate adjustment to remove the capital additions budgeted for IVVO in rebuttal.

Table 26

2022-2024 Capital Additions - AGIS (Distribution)

(Dollars in Millions)

State of MN Electric Jurisdiction Additions (includes AFUDC)	**2022 Budget**	**2023 Budget**	**2024 Budget**	**TCR Rider vs. Base Rates**
ADMS	$0.0	$0.0	$1.7	TCR Rider (with exception of internal labor)
AMI	$83.8	$109.5	$91.8	TCR Rider (with exception of internal labor)
FAN	$1.4	$1.1	$26.2	TCR Rider (with exception of internal labor)
FLISR	$3.4	$7.8	$7.8	Base Rates
IVVO	$0.0	$0.3	$3.7	Rebuttal adjustment to Base Rates
Total	**$88.6**	**$118.7**	**$131.2**	

The table below provides a breakdown of the AGIS capital amounts for Distribution that will be recovered in TCR Rider as compared to base rates. As I stated earlier, internal labor for ADMS, AMI, and FAN will be recovered in base rates but the remainder of the costs for these projects will be recovered in the TCR Rider.

Table 27

2022-2024 Capital Additions - AGIS (Distribution)

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
Total AGIS-Distribution Base Rates (Includes FLISR, IVVO, and includes internal labor for all AGIS projects)	$13.0	$20.4	$24.9
Total AGIS-Distribution in TCR Rider (excludes internal labor)	$75.6	$98.3	$106.3

b. FLISR

Q. HAS COMMISSION OUTLINED ANY FILING REQUIREMENTS RELATED ON THE FUTURE COST RECOVERY FOR AGIS INVESTMENTS?

A. Yes. In its September 27, 2019 Order related to the Company's request for approval to include ADMS in the TCR Rider, the Commission outlined information that would be beneficial in assessing future AGIS investments.[11] This requested information is provided below, in Section IV(C)(5) (O&M), and in Exhibit___(KAB-1), Schedule 4.

Q. WHAT IS FLISR?

A. FLISR (Fault Location, Isolation and Service Restoration) is a form of distribution automation that involves the deployment of automated switching devices that work to detect feeder mainline faults, isolate them, and restore power to unfaulted sections – decreasing the duration and number of customers affected by any individual outage. The FLISR application relies on three primary components to operate: (1) ADMS, for the central control and logic; (2)

[11] *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*, Docket No. E002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (Sept. 27, 2019).

intelligent field devices to detect faults and operate field equipment; and (3) the FAN, for wireless communications to each device. Fault Location Prediction (FLP) is a subset application of FLISR that indirectly considers and leverages sensor data from the field devices to locate a faulted section of a feeder and reduce patrol times necessary to locate a fault. The FLISR system is expected to reduce outage durations for customers and improve overall system reliability performance metrics, such as SAIDI and SAIFI. It should be noted that while outage durations will decrease, a customer may see an increase in the number of momentary (less than 5 minutes) outages as FLISR isolates the faulted section.

Q. HAS THE COMPANY PREVIOUSLY PRESENTED FLISR TO THE COMMISSION?

A. Yes. The Company previously sought certification of FLISR in its 2017 Biennial Grid Modernization Report[12] and as part of its 2019 IDP filing. In each case, the Commission did not certify FLISR but also did not foreclose the Company from bringing FLISR forward at a later time. For example, in its July 2020 Order on the Company's 2019 IDP the Commission's stated, "[d]enial of certification does not prevent Xcel from continuing work on IVVO and FLISR or seeking cost recovery through traditional means…."[13]

[12] *In the Matter of Xcel Energy's 2017 Biennial Distribution Grid Modernization*, Docket No. E002/M-17-775, XCEL ENERGY'S 2017 BIENNIAL DISTRIBUTION GRID MODERNIZATION REPORT (Nov. 1, 2017).

[13] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS at 15 (July 23, 2020).

Q. HOW DOES THE COMPANY'S CURRENT FLISR PROPOSAL DIFFER FROM THE ONE THAT THE COMPANY SOUGHT APPROVAL FOR IN 2019?

A. The only change is in the deployment schedule for FLISR. In 2019, the Company proposed to deploy FLISR from 2020-2028. The current deployment schedule is from 2021-2027.

Q. WHAT IS THE CURRENT DEPLOYMENT STRATEGY FOR FLISR?

A. The Company plans to deploy FLISR on approximately 208 feeders in Minnesota. The Company is selecting feeders for the deployment of FLISR based on the following criteria: (1) five-year reliability performance that takes into account the number of customers per feeder; (2) planned or recently completed projects that impact a feeder's reliability performance; (3) constructability. The Company is still determining its complete list of feeders where it will deploy FLISR and will continue to reevaluate its feeder selection as the deployment moves forward.

Q. WHAT ARE THE BENEFITS OF IMPLEMENTING FLISR?

A. The most significant quantifiable benefit of FLISR is improved reliability for our customers. We also expect to achieve certain operational efficiencies due to the increased visibility and information provided by the FLISR field devices. One of these benefits is the reduction in field trips for our employees to effect non-outage switching, enabled by the FLISR automated devices. Additionally, all remotely operable switches will necessarily have sensors which will provide operating data at strategic points along the feeders. This data will be useful in the refining planning models and hosting capacity analysis, allowing the planning engineer to more accurately distribute load along the feeders.

Q. WHEN WILL THESE RELIABILITY BENEFITS BE ACHIEVED?

A. Customers connected to feeders modeled in ADMS will begin seeing reliability benefits in steps. First, when faults occur on feeders that are modeled within ADMS, the algorithms will develop switching plans faster, which will result in faster outage restoration. At the same time, if fault magnitude information is available, the system will calculate the fault's probable location which will reduce patrol time. Second, for feeders equipped with automated devices, the operators will use remote capabilities to open and close switches, further improving the response time. This is referred to as "advisory mode." And third, when the Company has sufficient experience and confidence, the full automated capability of FLISR will be employed, bringing the full benefit of fast, automated switching to our customers. As such, we expect that benefits will begin in 2022 and continue to increase through 2028 as additional FLISR devices are deployed and when the fully automated capabilities are utilized.

Q. HOW WILL FLISR PROVIDE RELIABILITY BENEFITS?

A. Overall, implementing FLISR allows the Company to more efficiently restore power to our customers with the use of fewer resources and will improve our customer's outage experience. Specifically, if there is a fault on a feeder that is automated with FLISR, we will be able reduce the number of customers who experience a sustained outage by two-thirds and will shorten the duration of certain sustained outages that affect a substantial portion of our customers.

Q. HOW WILL FLISR REDUCE THE NUMBER OF CUSTOMERS WHO EXPERIENCE SUSTAINED OUTAGES?

A. FLISR will allow us to restore service to two-thirds of customers affected by an outage within minutes of a fault. In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will then step through the FLISR sequence. The first step is fault location, identifying the location of the fault to, at minimum, between two telemetered devices. Next, FLISR will proceed to isolation, in which ADMS will send open commands to any additional devices necessary to isolate the faulted section of feeder. Last, FLISR will execute supply restoration, which will generate a switching plan to restore load to all possible customers.

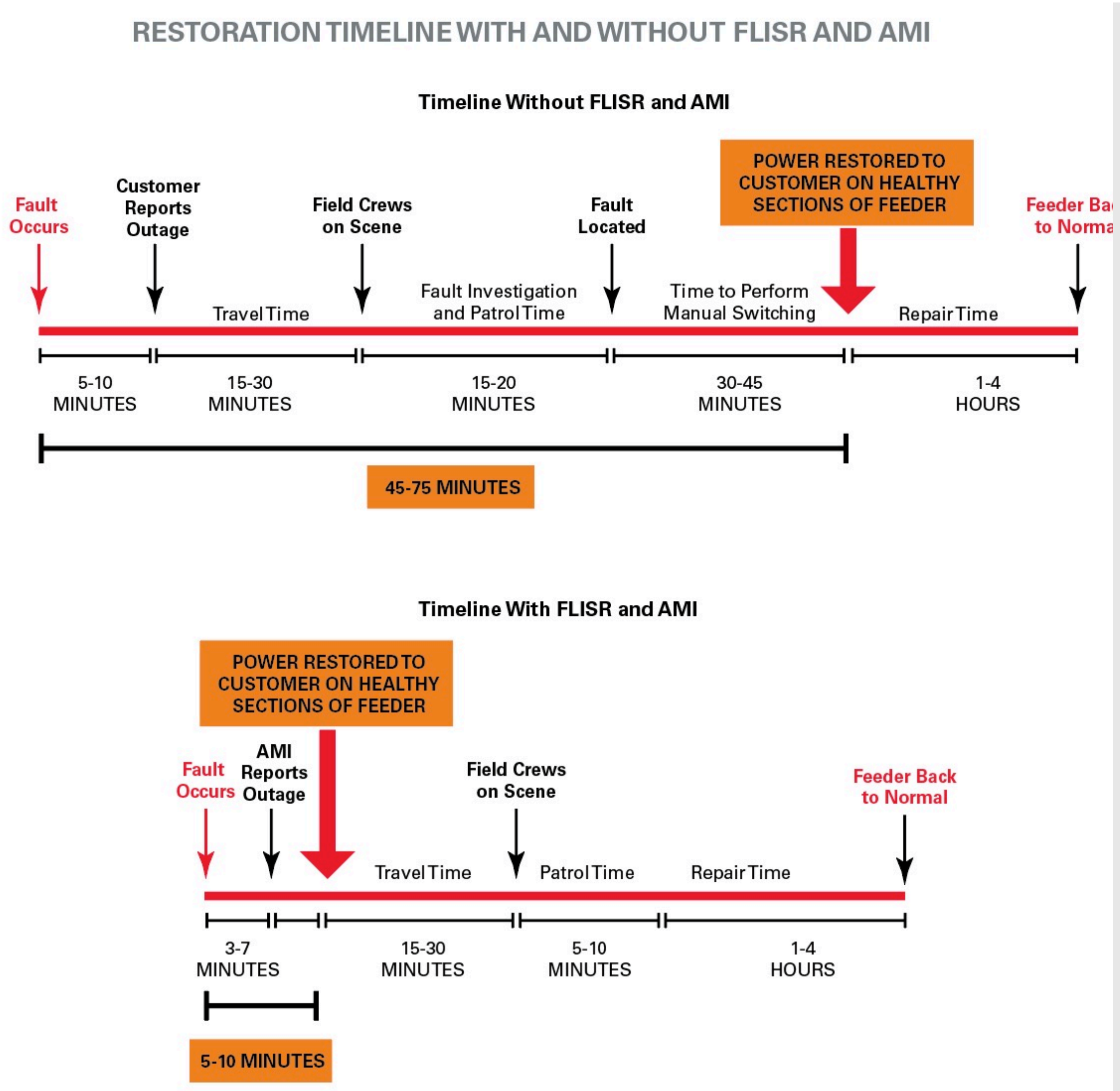
Restoration can be done manually or automatically within the system. Restoration considers not only device and feeder loading - but surrounding feeder and substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to investigate the fault event. This process is expected to take from 15-45 seconds from start to finish and by design, restore power to approximately two-thirds of the customers on that feeder. After the service restoration step, system operators will send a crew to the isolated section to investigate the fault event, make repairs, and restore service to the remaining customers.

Q. HOW WILL FLISR REDUCE THE OUTAGE DURATION FOR CUSTOMERS ON A FEEDER WITH A FAULT?

A. FLISR will also provide better fault location identification that will improve restoration times for those customers served by feeder experiencing a fault. Specifically, ADMS will run the FLP algorithm and predict where within a FLISR section the fault exists, which will reduce patrol times for Xcel Energy crews. As a result, crews will be able to move on to subsequent outages more quickly.

Figure 14 below illustrates how FLISR will improve restoration times for both customers on the healthy section of the feeder and those on feeder with a fault. The first timeline below shows the sequence of activities that currently take place, along with their approximate timeframes. The second timeline depicts the anticipated sequence of activities with fully-functional FLISR. The comparison is significant, a reduction in outage duration from 45-75 minutes to only 5-10 minutes for those customers not connected to the faulted section. Also, due to the fault location information, FLISR will also reduce the patrol time required for our crews to locate the fault from 15-20 minutes to 5-10 minutes. For those customers on the faulted sections, this is expected to result in quicker service restoration.

Figure 14



Q. ARE THERE OTHER BENEFITS OF FLISR?

A. Yes. Another benefit of FLISR is that it provides valuable data points that are helpful for system planning. FLISR provides key data at critical points along the system, which is fed into historical systems and can be leveraged by engineering to make decisions about how to plan and design the future grid. System planning uses historic measured load at a single point on the feeder to allocate that load across the feeder. With multiple FLISR devices on each feeder, the granularity of these data measurements will be enhanced across the feeder. The increased system visibility will also improve our reliability management efforts by increasing the quality and amount of the information we are able to analyze. In addition, these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

Q. WHAT ARE THE PRINCIPAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTING FLISR?

A. The capital costs associated with FLISR are: 1) asset costs; 2) asset installation; and 3) communications.

Q. WHAT IS INCLUDED IN THE ASSET COST CATEGORY?

A. This includes the capital costs for the FLISR devices (i.e., switches, reclosers, powerline sensors, and relays).

Q. HOW DID THE COMPANY ESTIMATE THE COSTS OF THESE DEVICES?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. As a result, we were able to use historical costs to develop the capital cost estimates for these devices. Our recent costs and experiences in Colorado provide confirmation that these costs estimates are reasonable.

Q. HAS THE COMPANY SELECTED THE VENDORS TO SUPPLY THE FLISR DEVICES?

A. Yes. The Company selected the vendors for the FLISR devices through our established Equipment Standards process. The process by which our materials are selected to become "standard" does involve periodic review, so as the market evolves, the Company will revisit the vendors selected to provide these devices and based on this review, these vendors may change. In addition, the Company's foresight into the needs for automation of certain devices had led to selecting devices in the past that were capable of the automation needed to implement FLISR. This is the case for reclosers, switch cabinets, and overhead switches.

Q. WHAT IS INCLUDED IN THE ASSET INSTALLATION AND LABOR COST CATEGORY?

A. The asset installation costs for FLISR include the capitalized costs for installing and commissioning FLISR devices (switches, reclosers, sensors, and relays).

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. We were able to use historical installation and labor costs to develop the capital cost estimates. Our recent costs and experiences in Colorado provide confirmation that these cost estimates are reasonable.

Q. WHAT IS INCLUDED IN THE COMMUNICATION COST CATEGORY?

A. The communications installation costs for FLISR include costs to install and communications endpoints associated with the FLISR equipment to ensure reliable and secure communications.

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. We were able to use historical costs to develop the capital cost estimates. Our recent costs and experiences implementing FLISR in Colorado provide confirmation that these cost estimates are reasonable.

Q. WHAT ALTERNATIVES TO FLISR DID THE COMPANY EVALUATE?

A. There are no real alternative technologies that provide the same reliability benefits as FLISR. As a result, the Company evaluated the following alternatives: (1) maintaining the current system and (2) delaying the deployment of FLISR.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THESE TWO ALTERNATIVES?

A. The Company determined that both were inferior options. Maintaining the current system means our ability to improve system reliability would be limited to process improvements related to our outage response procedures, which can only provide very limited incremental improvement. This is because absent FLISR, our ability to isolate, locate, and resolve faults is limited due to: (1) a lack of intelligent field devices that interact with the FAN and ADMS to restore service to a majority of customers on the faulted circuit; and (2) a lack of visibility and information regarding where the fault may have occurred on the feeder and the type of fault occurring. Given the limitations of the current system, we determined that FLISR was necessary to improving our customers' outage experience. The Company further determined that delaying the implementation of FLISR only serves to defer the realization of the reliability benefits provided by FLISR. Further, delaying the deployment of FLISR has likely effect of increasing its costs due to inflation as well as potential increases in labor and material costs.

Q. HAS THE COMPANY PROVIDED A COST BENEFIT ANALYSIS FOR FLISR?

A. Yes. A cost benefit analysis for FLISR is provided Exhibit___(KAB-1), Schedule 4. This cost benefit analysis is similar to the one prepared by the Company in 2019[14] but has been updated to reflect the current costs for FLISR and the current deployment schedule. On a total resource benefit-to-cost ratio, FLISR benefits are expected to exceed FLISR costs, with an expected cost-to-benefit ratio of approximately 2.05 to 2.28.

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

A. During the term of this multi-year rate plan, the Company will be making needed investments to ensure the reliability, resiliency, and future capabilities of our Distribution system. These investments will be focused on the core assets that form the last-mile of electric delivery system. This includes replacements of aging poles, cables, and substation transformers and breakers. We are also implementing the foundational components of a modern grid through our AGIS initiative, AMI meters and a FAN which will provide immediate benefits for customers, and also enable future capabilities. While the level of capital investments that Distribution seeks to recover in this rate case are higher than our historical amounts, these investments are reasonable and necessary to ensure the health, safety, and reliability of our distribution system as well as making the necessary investments to advance our distribution system to meet our customers' current and future needs.

[14] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666, INTEGRATED DISTRIBUTION PLAN (Nov. 1, 2019).

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN THE COMPANY'S DISTRIBUTION O&M BUDGET?

A. The Distribution O&M budget includes costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes costs related to vegetation management and damage prevention. Additionally, the Distribution O&M budget includes miscellaneous materials and tools necessary to build, operate, and maintain our electric distribution system and fleet (for example, vehicles, trucks, and trailers). The O&M component of fleet consists of those expenditures necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet to O&M based on the proportion of the Distribution fleet utilized for O&M activities as opposed to capital projects.

Q. WHAT ARE THE GENERAL CATEGORIES OF DISTRIBUTION'S O&M BUDGET?

A. Distribution's O&M budget can be broken into six general categories: (1) internal labor; (2) contract labor; (3) vegetation management; (4) damage prevention; (5) AGIS; and (6) other (such as materials, fleet, employee expenses). I discuss these six categories in further detail below.

Q. PLEASE PROVIDE DISTRIBUTION'S O&M EXPENDITURES FROM 2018 THROUGH THE 2024 BUDGET YEAR.

A. Table 28 below provides O&M expenditures by category, showing actual O&M expenditures for 2018 to 2020, forecast O&M expenditures for 2021 (half year actuals and half year forecast), and budgeted O&M for 2022, 2023, and 2024.

Our O&M actuals, forecast, and budgets is also provided in Exhibit___(KAB-1), Schedule 3. While our 2024 O&M expenses are higher than our 2018 O&M expenses overall, this increase represents a modest 2.2 percent annual increase per year from 2018 to 2024.

Table 28

Distribution O&M Expenses

(Dollars in Millions)

NSPM- Electric	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Internal Labor	50.6	47.7	43.0	43.9	46.5	49.0	50.5
Contract Labor	9.4	14.5	9.2	10.5	10.9	11.5	11.5
Vegetation Management	32.4	35.4	23.8	41.2	43.4	46.0	46.2
Damage Prevention	8.1	7.7	11.0	13.1	14.9	14.4	14.6
AGIS[1]	0.9	1.1	1.6	5.2	6.0	4.7	4.0
Other (Materials, Fleet, Employee Expenses, etc.)	15.3	10.5	7.8	7.1	6.0	6.0	6.0
Total	**$116.7**	**$116.8**	**$96.5**	**$121.0**	**$127.7**	**$131.6**	**$132.9**

Q. WHAT WERE THE OVERALL TRENDS FOR DISTRIBUTION'S O&M EXPENSES FROM 2018 TO 2020?

A. Distribution's O&M expenditures were held flat from 2018 to 2019, and then decreased in 2019 to 2020. I explain the reasons for these changes below.

Q. PLEASE EXPLAIN WHY DISTRIBUTION O&M EXPENSES STAYED RELATIVELY FLAT FROM 2018 TO 2019.

A. Our 2019 actual O&M expenditures increased by less than 0.1 percent, compared to 2018 actuals due to several factors. First, O&M costs in 2018 included a mutual aid event that involved Xcel Energy sending employees to Puerto Rico in early 2018 to assist with restoring the power to the island after Hurricane Maria hit in September 2017. This work and associated expenses were limited to 2018, resulting in a decrease in O&M in 2019 compared to 2018. This reduction in expenditures was offset by increases related to O&M for storm restoration and vegetation management. The frequency, and in some cases the severity, of the storms we experienced in 2019 was higher than in prior years. Specifically, in 2019 a total of 178 storm work orders were issued for storm restoration work in the State of Minnesota compared to only 88 storm work orders in 2018, 61 in 2017, and 89 in 2016. Our vegetation management expenses increased in 2019 due to an increase in the number of line miles maintained in 2019 plus an increase in our contractor rates from 2018 to 2019. Finally, O&M electric transformer and meter first-set credits or "first-set credits" came in lower in 2019 as compared to 2018 resulting in a net increase to 2019 O&M expenditures. Partially offsetting the increases described above was a mixed work adjustment for 2019 that reduced O&M costs.

Q. WHAT ARE THE "FIRST-SET CREDITS" THAT YOU MENTIONED IN YOUR PREVIOUS ANSWER?

A. First-set credits are O&M labor, transportation, and miscellaneous material credits associated with the installation of meters and line transformers. Because of the way meters and transformers are accounted for (fully installed costs are capitalized upon purchase instead of installation), the actual labor, transportation and miscellaneous materials used to install this equipment is expensed to O&M to avoid accounting for these expenses twice. An equal and opposite credit is then applied upon purchase to offset these actual installation costs that are expensed to O&M.

Q. WHAT IS A MIXED WORK ADJUSTMENT THAT YOU DISCUSSED ABOVE?

A. A mixed work adjustment is used to properly allocate costs between capital and O&M for certain routine work. The main two areas impacted by mixed work adjustments in 2019 were: (1) Engineering and Supervision (E&S) and (2) routine pole replacements. In 2019, the Company completed an updated E&S analysis that resulted in increased capitalization percentage for our E&S back-office labor for 2019 as compared to previous years. We typically conduct an updated E&S analysis every two to three years to keep our back-office personnel capital/O&M splits up-to-date according to the latest work and activities the Distribution Business unit is performing.

A mixed work adjustment was also made for our routine pole replacement work. Routine pole replacements are the standard pole replacements performed by Distribution to replace aging or failing poles across our system. To update the capital and O&M allocation for pole replacements, Distribution performed time-studies in the field of all the various activities involved in a pole replacement project (e.g., pole framing, pole installation, equipment installations). Our Capital Asset Accounting area also has performed a comparison of Xcel Energy capitalization standards to those used by peer utilities to understand how the rest of the industry identifies capital property and activities for pole replacements. The result of both the field time-studies and industry review showed that our current allocation was under allocating costs to capital and over allocating costs to O&M for these pole replacements.

Q. PLEASE EXPLAIN THE DECREASE IN O&M EXPENSES FROM 2019 TO 2020.

A. Distribution's 2020 O&M expenditures were lower than 2019 due to the impacts of the COVID-19 public health emergency. As a result, and as discussed further by Ms. Ostrom, our 2020 O&M costs may not provide an appropriate reference point for future O&M expense levels or the reasonableness of our budgeting processes. In response to the impact that COVID-19 had on our communities, customers, and operations in 2020, Distribution adjusted operations to keep employees and the community safe as well as to maintain operational flexibility as the Company faced uncertainties about the depth and duration of the impacts of COVID-19. This included temporary reductions to O&M expenses where possible without impacting the safety of our customers, employees, and the community. Among the adjustments, Distribution temporarily reduced vegetation management activities in 2020 and reduced internal labor costs by scaling back on overtime. There were also reductions in materials and a decrease in employee expenses due to less travel and associated expenses in the 2020 due to COVID-19 restrictions. In addition, O&M storm restoration expenditures were lower than 2019 (which as described above, had unusually high storm restoration activity). Further, 2020 O&M was further reduced due to due to an increase in first-set credits in 2020 as compared to 2019.

Q. WERE THERE ANY AREAS OF DISTRIBUTION'S O&M BUDGET THAT INCREASED IN 2020?

A. Yes. Damage Prevention O&M expenditures increased due to an increase in the number of locates performed in 2020 as compared to 2019. As people stayed home more in 2020 due to COVID-19 restrictions, many used this time to start home remodeling and landscaping projects that required our locating services.

Q. HOW DOES THE 2021 O&M FORECAST COMPARE WITH 2020 ACTUAL O&M COSTS?

A. The 2021 O&M forecast is higher than 2020 actuals. As I discussed earlier, during 2020, Distribution reduced O&M expenses due to COVID-19. For 2021, we are forecasting to return to a level of O&M expenditure that is comparable to our pre-COVID levels, with incremental O&M related to completing work that was originally budgeted to be completed in 2020. For example, a large driver of the increase in O&M in 2021, as compared to 2020, is an increase in vegetation management to start to make up for some of the line clearing that was originally planned, but not completed, in 2020. These costs will continue through 2024. Additional O&M increases in 2021, as compared to 2020, relate to increased contractor rates for Damage Prevention due to new vendor contracts that took effect in 2021 following a competitive RFP process and increased labor expenses associated with implementing AGIS.

Q. WHAT ARE THE OVERALL TRENDS FOR DISTRIBUTION'S O&M BUDGETS FOR 2022-2024?

A. Distribution's O&M budgets for 2022-2024 are higher overall than actual O&M expenditures in recent years for the reasons that I will describe in detail below.

However, during the multi-year rate plan period itself, our Distribution O&M budgets increase modestly, with a 3.0 percent increase from 2022 to 2023, and a 1.0 percent increase between 2023 and 2024.

Q. HOW DOES THE 2022 BUDGET COMPARE WITH 2020 ACTUAL COSTS?

A. The 2022 O&M budget is higher than 2020 actuals. However, the majority of this increase reflects a restoration of budgeted O&M expenditures to pre-COVID levels (the 2018-2019 average), without considering any annual inflation impacts from 2020 to 2022. The remaining increase is largely driven by an incremental vegetation management expenditures necessary to continue to complete vegetation management work that was deferred in 2020.

Q. WHAT ARE THE OTHER DRIVERS OF THE INCREASE IN O&M BETWEEN 2020 AND 2022?

A. We have also budgeted an incremental increase in Damage Prevention for 2022 compared to 2020 actuals because our current Damage Prevention contract rates are higher than the 2020 rates. As I discussed earlier, new Damage Prevention contracts took effect in 2021 following a competitive RFP process. The 2022 O&M budget also includes an additional expenses for internal and contract labor necessary to implement the AGIS initiative, with AMI meter deployment beginning in 2022. While our O&M expenses are increasing from 2020 to 2022, Distribution is taking steps to keep these increases as low as possible by implementing certain productivity improvements.

Q. WHAT ARE THE PRODUCTIVITY IMPROVEMENTS THAT THE COMPANY IS PLANNING TO IMPLEMENT IN 2022 TO REDUCE O&M EXPENSES?

A. An example of these productivity improvements is our centralized scheduling initiative. Phase I of this initiative, the Design & Construction Process, is expected to be fully implemented by the end of 2021. Once fully implemented, this centralized scheduling initiative is expected to reap efficiency benefits by allowing the Company to review and schedule capital and O&M workload over entire regions at the NSPM operating company level. This will ensure that projects are proactively planned, designed, and resourced well ahead of construction. This is expected to allow the Company to realize efficiency gains at both the design and construction phases of our work, thus reducing overall O&M costs due to false starts and delays. The centralized scheduling concept will also provide a greater ability to share both internal and external resources across various service center offices.

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

A. Distribution's 2022 O&M budget is higher than the 2021 O&M forecast. This is primarily due to increased vegetation management costs described previously; an increase in damage prevention costs due to an increased locate volume forecast in 2022 compared to 2021 and the increased vendor contract costs; an increase in O&M to support an $52 million in increased in capital Asset Health and Reliability and Capacity work budgeted in 2022 compared to 2021; and additional AGIS O&M to support AMI meter deployment. Our traditional labor/non-labor inflationary increases are expected to be largely offset by the continuous improvement items discussed previously for 2022.

Q. WHAT IS THE ANNUAL LABOR/NON-LABOR INFLATION THAT YOU MENTIONED?

A. Annual labor/non-labor inflation refers to the annual base pay increases for internal labor and annual inflation associated with all non-labor components of our O&M budget. This is estimated as a 2.5 percent annual increase in base pay for bargaining employees and a 3 percent increase for non-bargaining employees. We have also included a 1 percent annual inflationary increase for non-labor O&M expenses.

Q. HOW DOES THE 2023 O&M BUDGET COMPARE WITH THE 2022 BUDGET?

A. The $131.6 million in O&M costs budgeted for 2023 is an increase of compared to 2022. This increase is primarily driven by an increase in annual labor/non-labor annual inflation plus an increase in vegetation management expenditures that is partially offset by reductions in budgeted AGIS O&M compared to 2022. This reduction in AGIS O&M is due to reduced training and readiness expenses as AMI meter and FAN deployment will be well underway by 2023.

Q. HOW DOES THE 2024 O&M BUDGET COMPARE WITH THE 2023 BUDGET?

A. The $132.9 million in O&M costs budgeted for 2024 is a slight increase compared to 2023. This increase is primarily driven by an increase in annual labor/non-labor inflation that was partially offset by a reduction in budgeted AGIS O&M compared to 2023.

B. Distribution O&M Budget Development and Management

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

A. Our O&M budgeting process takes into account our most recent historical spend in the various areas of Distribution and applies known changes to labor rates and non-labor inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities and/or maintenance projects embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (e.g., excessive storm activities or one-time O&M projects). We then couple the normalized historical spend information with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year. For example, for our major maintenance programs such as cable fault repairs and vegetation management, we review annual expected units/line-miles to be maintained and ensure required O&M dollars are adjusted accordingly.

I note that we also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we continuously are working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies. These improvements are already factored into our O&M budgets.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ON HOW SEVERE WEATHER IMPACTS DISTRIBUTION'S O&M EXPENSES EACH YEAR?

A. Our annual O&M expenses are influenced by the magnitude and frequency of significant severe weather and storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a "typical" year for severe weather. Table 29 below highlights the variability of O&M spending over and above base labor and transportation (i.e., overtime, materials, and contractors) for storm restoration events from 2016 to 2020.

Table 29
Annual NSPM O&M Storm Restoration Expenses
(Dollars in Millions)

2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	5-Year Average
$2.80	$1.10	$1.90	$6.90	$3.70	$3.28

As shown in Table 29, the Company experienced significantly higher storm restoration expenses in 2019 compared to our five-year average. This was primarily due to the frequency and, in some cases, the severity of storms we experienced in 2019, as discussed above. Additionally, in 2019 many storms occurred on weekends, which resulted in increased O&M due to overtime rates for certain employees. Further, the Company cannot predict or budget for extraordinary major storm events. For example, on April 10, 2020 a major storm hit the metro area, and there was widespread damage such that Xcel Energy required storm restoration assistance from other utilities.

Given the inherent variability and unpredictable nature of storm events, our O&M budgets each year consider the most recent five-year storm averages, and the various expenditure categories that include storm restoration activities are budgeted accordingly. The most recent five-year average (2016-2020) for storm restoration expenses for NSPM is $3.28 million.

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

A. We monitor our O&M expenditures on a monthly basis. In partnership with our Finance Area, we report out on our monthly and year-to-date actual expenditures versus budgets/forecasts, including deviation explanations for various categories of expenditures. This reporting is provided down to the individual Director management level and in some cases down to individual manager business unit levels as required. Monthly review meetings are conducted at various levels to determine any pressure points and remediation plans that are needed to manage our overall O&M expenditures and ensure proper prioritization of those expenditures.

C. O&M Budget Detail

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

A. In this section, I describe in detail the components of Distribution's O&M budget. I will describe each component, discuss any changes to O&M for that component over the course of the MYRP, and discuss steps the Company takes to minimize O&M cost increases for that particular O&M budget category.

1. Internal Labor

Q. WHAT IS INCLUDED IN THE INTERNAL LABOR CATEGORY?

A. This category represents the O&M portion of salaries, straight time labor, overtime, and premium time for all Distribution internal 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. Our internal labor costs for 2018-2024 are provided in the table below.

Table 30

Internal Labor

(Dollars in Millions)

NSPM-Electric	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Internal Labor	$50.6	$47.7	$43.0	$43.9	$46.5	$49.0	$50.5

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN INTERNAL LABOR COSTS FROM 2022 THROUGH 2024?

A. The 2022-2024 budgets for internal labor include an annual base pay increases of 3 percent for non-bargaining and 2.5 percent for bargaining employees. The annual base pay increases for our bargaining and non-bargaining employees are discussed in detail in the Direct Testimony of Company witness Ms. Ruth K. Lowenthal.

Another driver of the increase in internal labor costs is Distribution's plan to hire 24 additional bargaining unit employees in 2021 through 2022. These additional employees are needed to assist with the increase in Asset Health and Reliability projects as well as to address our DER workload and programs.

Q. PLEASE PROVIDE ADDITIONAL INFORMATION AS TO WHY THESE 24 ADDITIONAL EMPLOYEES ARE NEEDED.

A. Specifically, we plan to hire 20 additional line workers to address the increase in Asset Health and Reliability projects in the coming years as discussed above. To ensure we are able to timely address DER requests, we will be adding a total of three additional Designers as well one Engineering Analyst which will be dedicated to EVs and addressing the workload associated with this new program. Finally, we will be adding two new Engineers to support of the increased workload coming out of our Community Solar Gardens Program.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INTERNAL LABOR COSTS.

A. Our centralized scheduling process that I discussed earlier is one way that we are seeking to minimize internal labor costs. Additionally, we are currently reviewing current work processes to find opportunities to make those processes more efficient. As previously mentioned, our mixed work review processes have also yielded benefits to our internal labor O&M expenditures.

2. Contract Labor

Q. WHAT COSTS ARE INCLUDED IN DISTRIBUTION'S O&M BUDGET FOR CONTRACT LABOR?

A. This category represents our use of contract labor and consultants to perform O&M work on our distribution system. This also includes the delivery services for meters and transformers along with ancillary services such as barricades, flaggers, and restoration. I note that contract labor performs the majority of our vegetation management and damage prevention work but these costs have been broken out into separate categories that I discuss below.

Q. HOW HAVE YOUR O&M COSTS FOR CONTRACT LABOR BEEN TRENDING?

A. Our contract labor costs for 2022-2024 are being held essentially flat as compared to 2018-2020. This is being accomplished by both our plan to add 24 internal employees that will result in a reduction in our contract labor needs in the near term plus our internal reporting improvements and overtime controls. However, in 2023, our contract labor costs are expected to slightly increase due to the need for additional contract labor to assist with the number of Asset Health and Reliability projects planned for that year.

Table 31

Contract Labor

(Dollars in Millions)

NSPM-Electric	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Contract Labor	$9.4	$14.5	$9.2	$10.5	$10.9	$11.5	$11.5

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE CONTRACT LABOR COSTS.

A. The primary benefit of contract labor is that the Company is able to request competitive bids for these services to obtain well-trained and established work forces specializing in these areas. In addition, by contracting these services, the Company has the flexibility to easily ramp up and ramp down the number of contractors that it needs to respond to different volumes of workloads. To minimize our contract labor costs we partner with our key contract services and material vendors to look for ways to mutually reduce rates by how we structure those contracts and/or identifying opportunities to remove costs through efficiency improvements between our Company and those vendors. As previously mentioned, our mixed work review processes have also yielded benefits to our O&M expenditures for contract labor.

3. Vegetation Management

Q. PLEASE DESCRIBE THE COMPANY'S VEGETATION MANAGEMENT PROGRAM.

A. The purpose of the vegetation management program is to support the Company's safety and reliability goals and objectives by controlling the growth of, and the removal of encroaching vegetation near electrical lines and other critical infrastructure while remaining compliant with federal, state, and local laws and ordinances. The Company's objective is to perform routine vegetation management near distribution lines on a five-year rotation or cycle and a four to five-year rotation or cycle for transmission lines (depending on voltage class), and non-routine vegetation clearance in high-risk areas as determined necessary.

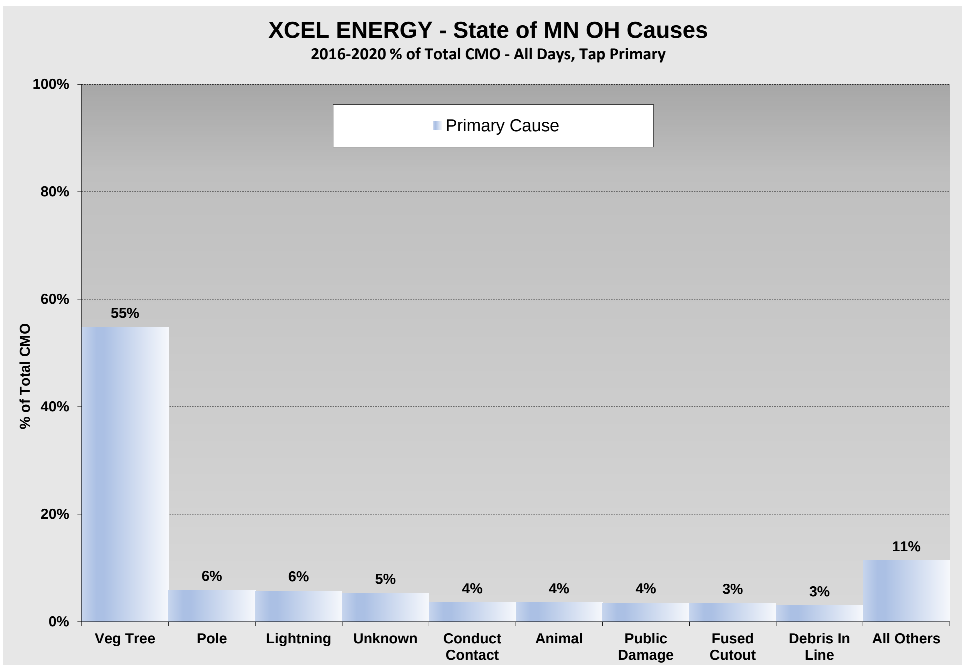
To manage incompatible vegetation near electrical lines, the Company uses qualified contractors to execute annual work plans created by vegetation management team. The vegetation management program minimizes tree-related interruptions, adheres to transmission NERC standard FAC-003, ANSI safety standard Z133.1, and work quality standard A300, and follows NESC Section 218. Other areas of responsibility of the vegetation management program include customer communication and relations, and customer requested vegetation consultation.

Q. WHY IS IT IMPORTANT FOR THE COMPANY TO HAVE AN EFFECTIVE VEGETATION MANAGEMENT PROGRAM?

A. An effective vegetation management program is essential to providing reliable service to our customers. Tree-related incidents are among the top two causes for electrical outages on our overhead distribution system. In addition, as shown in Figure 15 below, vegetation-related outages account for the highest percentage of CMO on our overhead system. That said though, our vegetation management program has been successful in that it typically results in 90 percent of the vegetation outages been deemed non-preventable. Constant review and evaluation of the effectiveness of vegetation management practices and tools, as well as consideration of new and changing technology and industry trends is the best way to ensure that preventable tree-related interruptions are minimized, public and employee safety is addressed, and various regulatory compliance requirements are met.

Figure 15

Overhead Outages by Cause in Minnesota for 2016-2020



Q. HOW DOES THE COMPANY BUDGET FOR ITS VEGETATION MANAGEMENT PROGRAM?

A. The vegetation management budget includes costs primarily associated with transmission and distribution routine cycle maintenance, customer requested work, Company facility work (e.g., substation grounds). Vegetation management budgets are based on a number of considerations including historic costs of cycle work, number of miles associated with future cycle years, increases or decreases in anticipated non-cycle work volumes, and vegetation management contractor market costs.

Q. WHAT ARE THE MAIN COST DRIVERS FOR THE VEGETATION MANAGEMENT CATEGORY?

A. The main cost drivers in this category include the cost of distribution and transmission routine cycle work and the volume of customer requested vegetation work.

Q. HOW WERE DISTRIBUTION'S VEGETATION MANAGEMENT COSTS TRENDING FROM 2018-2021?

A. During this period, with the exception of 2020, our vegetation management expenses increased during this period. The primary drivers of this increase in vegetation management costs are: (1) contracted labor cost increases and (2) significant vegetation growth. Beginning in 2019, our contracted labor costs increased primarily due to a very competitive job market for tree trimmers. This competitive job market is the result of fewer qualified personnel in the field of tree trimming and the loss of a number of tree trimming personnel who have relocated to the California wildfire region where labor rates are much higher than Minnesota.

Second, greater annual vegetation growth in recent years, due to higher spring rainfall totals, has also resulted in higher vegetation management costs. Rainfall data from the Minneapolis-St. Paul weather station for April through June, the months when trees are actively growing, shows that average annual rainfall has increased by 2.6 inches from 2016-2018 (10.7 inches/year) to 2019-2020 (13.3 inches/year). This is almost a 25 percent increase. These higher rainfall totals led to more vegetation growth in these years that required more time to trim and also increased removal costs. In 2020, as discussed above, we reduced vegetation management work in 2020 that resulted in fewer line miles being maintained and lower vegetation management costs in that year.

Table 32
Vegetation Management
(Dollars in Millions)

NSPM-Electric	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Vegetation Management	$32.4	$35.4	$23.8	$41.2	$43.4	$46.0	$46.2

Q. WHAT CHANGES IN THE VEGETATION MANAGEMENT BUDGET DO YOU ANTICIPATE FOR 2022 THROUGH 2024?

A. As shown in the table above, the vegetation management budget is approximately $43.4 million for 2022, $46.0 million for 2023, and $46.2 million for 2024. These budgets take into account the continued impact of contract labor cost increases and significant vegetation growth. In addition, our 2022-2024 budget reflects an increase in the number of line miles maintained each year in order to make up for the work that was delayed in 2020.

Q. DO THE BUDGETS PRESENTED HERE REFLECT ONGOING COST CONTROL EFFORTS RELATED TO VEGETATION MANAGEMENT?

A. Yes. The Company is in the process of exploring several options to minimize vegetation management expenditures including:

- *New Technology*: While it is difficult to replace labor that performs line clearance, their work can be optimized using emerging technology, tools and advanced analytic approaches that are now available. Recent studies and testing indicates that careful deployment of these new tools may help to reduce annual vegetation management costs without reducing the reliability, safety, and customer satisfaction. Of particular interest is the use of remote sensing technology (i.e., satellite imagery, LiDAR) that provides visual representation of current vegetation conditions in the field to a desktop that can be analyzed and assessed to determine clearance needs and estimated costs.

- *New Analysis*: Using the same advanced analytics and tools mentioned previously, a growing number of utilities are developing models to create predictive failure and trimming cost curves to optimize the trim cycle at the individual circuit level. This approach ensures the utility is addressing the right areas with the right resources at the right time to improve reliability and optimize costs.
- *Leveraging Size*: Bundling the entire volume of work across all operating companies to increase leverage when negotiating pricing with contractors.
- *Contractor Controls*: Controlling costs through rigorous negotiations with contractors which includes open-book, transparent pricing methods.
- *Contractor Evaluation System:* Using a formal contractor evaluation systems (competitive environment) to evaluate contractors against each other based on a set of known and measurable performance measures including cost and quality.
- *Scheduling and Management Improvements*: Starting in 2019 and expected to last into 2022, we have engaged the Boston Consulting Group (BCG) to help us gain additional efficiencies in our line clearance scheduling and management activities. One outcome of this engagement will be a new data analytics and software package that is expected allow for much more

efficient scheduling of line clearance activities to direct resources more strategically and prioritizing to areas that may need to be revisited for vegetation management sooner than others to optimize our O&M line clearance budgets.

We have incorporated $2.0 million of anticipated cost reduction into our 2021 vegetation management forecast, growing to $2.5 million in 2022, and then up to $3.0 million in 2023 and going forward to reflect the anticipated cost savings from the efficiencies discussed above.

4. Damage Prevention

Q. WHAT IS THE DAMAGE PREVENTION PROGRAM?

A. The Damage Prevention program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents.

Q. ARE UNDERGROUND DAMAGES A SIGNIFICANT RISK TO NSPM'S ELECTRIC SYSTEM?

A. Yes. Whenever excavation and related construction occurs, there is a risk of damage to NSPM's underground electric distribution facilities. As a result, NSPM continues to institute a variety of outreach efforts to excavators regarding the importance of using Gopher State One Call (811) for best excavation practices.

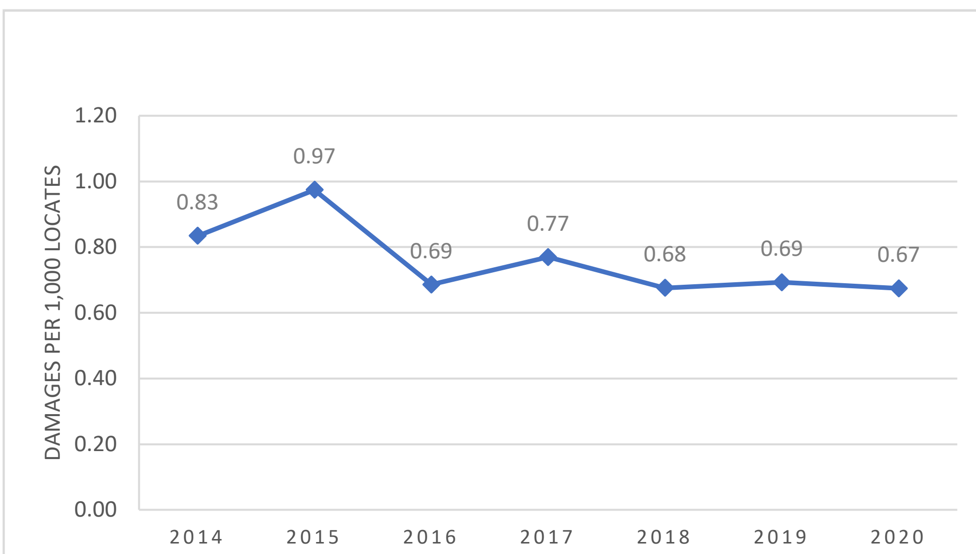
It is also critical that the Company's electric infrastructure is located accurately before excavating to ensure safety for the workers, as well as the public, around the work site. To that end, NSPM continually re-evaluates its damage prevention programs to increase their effectiveness. The Company also provides leadership in several industry organizations where it obtains and shares information about best practices for reducing public damage. We also include best practices and performance requirements in our vendor contracts in an effort to continually improve and enhance our performance.

Q. HOW IS NSPM PERFORMING WITH RESPECT TO DAMAGE PREVENTION?

A. Figure 16, below, illustrates the number of electric damages per 1,000 locates from 2013 to 2020. As indicated by this figure, the Company has seen almost a 24 percent reduction in damages per 1,000 locates on our system since 2014 due to our damage prevention program.

Figure 16

MN Electric Damages per 1,000 Locates



Q. HOW ARE LOCATES PERFORMED BY NSPM?

A. The Company is required by law to locate underground facilities when requested. To meet this requirement, the Company is in good standing with

Gopher State One Call and utilizes both contracted outside vendors and internal labor to perform locate requests.

Gopher State One Call, formed in response to the legislature's adoption of Minnesota Statutes Chapter 216D, provides a centralized phone center for customers to call to request locates. The cost for this service is free to customers; however, the Company pays Gopher State One Call a cost per ticket.

To respond to tickets resulting from calls to the centralized phone center, the Company utilizes both internal employees and contracts with external contractors to perform locates and provide field support and audit services. NSPM has contracts with four external contract vendors. These contracts commenced on February 1, 2021 and are effective until January 31, 2024. The Company selected these four contractors following a competitive request for proposal (RFP) process in 2020.

Q. HOW DOES THE COMPANY BUDGET FOR DAMAGE PREVENTION?

A. The budget for damage prevention is based on several factors: (1) contract pricing of our damage prevention service providers multiplied by the forecasted number of locate tickets; (2) internal labor costs based on approved headcount and labor rates from the collective bargaining process, and (3) miscellaneous costs (materials, fleet, other) based on historical actuals.

Q. HOW HAVE DAMAGE PREVENTION COSTS BEEN TRENDING IN RECENT YEARS?

A. As shown in Table 33 below, damage prevention costs have been increasing due to an increase in the number of locate requests as well as higher contract labor costs due to new vendor contracts that went into effect on February 1, 2021.

Table 33

Damage Prevention O&M Expenses

(Dollars in Millions)

NSPM-Electric	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Labor	1.6	1.6	1.6	1.6	2.8	2.9	3.0
Outside Services	6.1	5.7	9.1	11.2	11.6	10.9	11.0
Materials and Commodities	-	-	-	-	0.2	0.2	0.2
Other	0.3	0.4	0.4	0.3	0.3	0.3	0.3
Total	**$8.1**	**$7.7**	**$11.0**	**$13.1**	**$14.9**	**$14.4**	**$14.6**

Q. WHY ARE THE 2022-2024 BUDGETS FOR DAMAGE PREVENTION HIGHER THAN 2020 ACTUALS?

A. This increase is due to two factors: (1) a forecasted increase in the number of locates per year and (2) an increase in contract labor costs due to the new vendor contracts that went into effect on February 1, 2021.

Q. WHAT IS THE COMPANY FORECASTING IN TERMS OF NUMBER OF LOCATES FOR 2022-2024?

A. The Company is forecasting a 3.0 percent annual increase from 2022 through 2024. Table 34 below provides the number of actual electric locates from 2014 through 2020, forecasted locates for 2021, and budgeted locates from 2022 through 2024. The Company is forecasting a 3.0 percent annual increase from 2022 through 2024.

Table 34

NSPM Volume of Electric Locates

2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
413,469	446,838	446,383	460,483	459,904	470,697	502,348	502,636	517,715	533,246	549,243

Q. WHY IS A 3 PERCENT INCREASE IN THE NUMBER OF LOCATES FROM 2022 THROUGH 2024 REASONABLE?

A. As shown in the table above, the number of electrical locates performed by the Company has generally increased each year over year with the exception of a couple outlier years. Most recently, from 2018 to 2020, locates increased on average by 4.5 percent per year. Based on this recent history, the Company budgeted for a 3.0 percent annual increase in the number of locates for 2022 through 2024. This budgeted 3.0 percent increase is conservative given the recent history of a 4.5 percent annual average increase as well as the strong housing market and recent increase in home remodeling and landscaping projects. For instance, in July 2021, the number of permits for single family homes increased by 10 percent as compared to July 2020.[15] In addition, the currently pending federal infrastructure bill, if passed, will result in an increase in government construction projects such as roads, bridges, and expanded broadband installation over the term of this multi-year rate plan that will also drive an increase in the number of locates.

[15] https://newsroom.housingfirstmn.org/twin-cities-homebuilding-continues-push-ahead-despite-numerous-headwinds/

Q. CAN YOU EXPLAIN THE SIGNIFICANT INCREASE IN THE NUMBER OF LOCATES IN FROM 2019 TO 2020?

A. This increase in locates was due to an increase in property owner performing projects while at home due to the COVID-19 restrictions. This work included home remodeling projects and landscaping projects. This was on top of the normal annual increase in the number of locates that we typically expect to see each year.

Q. WHY WAS THERE AN INCREASE IN VENDOR COSTS ASSOCIATED WITH THE NEW DAMAGE PREVENTION CONTRACTS THAT WENT INTO EFFECT FEBRUARY 1, 2021?

A. At the time these contracts were negotiated, the labor market for these jobs was tight. Additionally, the insurance premiums to protect the vendor from damages caused by inaccurate locates performed by their employees increased. The Company went through a competitive bidding process prior to selecting its damage prevention vendors. This competitive bidding process solicited bids from a number of different vendors.

Q. WHY DOES THE COMPANY UTILIZE OUTSIDE CONTRACTORS TO PERFORM UNDERGROUND LOCATES?

A. The Company receives a significant amount of locate requests during the construction season when the ground is free of frost. The Company staffs internal employees to sustain year-round requests and utilizes contractors to supplement locate requests during peak construction periods.

Q. CAN YOU SUMMARIZE SOME OF THE ISSUES WITH HIRING ADDITIONAL INTERNAL LABOR TO PERFORM MORE OF THE ELECTRIC LOCATES.

A. Yes. First, we would have to staff internally to perform high levels of seasonal work, and ensure we could do so effectively under our collective bargaining agreements. Additionally, our outside vendors assume the risk of inaccuracies of these locates and any resulting damages, whereas using internal labor for that work would increase risk and likely shift damage costs (in the case of inaccurate locates third-party claims or other issues) to the Company.

5. AGIS

Q. WHAT TYPES OF O&M COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. Distribution's AGIS related O&M costs include internal labor, contract labor, vendor services, and materials. The O&M costs for Distribution associated with AMI, FAN, and Other (with the exception of internal labor) will be recovered through the TCR Rider. Internal labor for AMI, FAN, and Other and all Distribution O&M costs for ADMS and FLISR will be recovered in base rates. As I noted earlier, the Company will be making an adjustment in rebuttal to remove costs associated with IVVO from this rate case. Table 35 below provides a breakdown of the O&M costs by AGIS project and the amounts that will be recovered in the TCR Rider versus base rates.

Table 35

AGIS O&M

NSPM Electric-Distribution

(Dollars in Millions)

AGIS Program	2022 Forecast	2023 Forecast	2024 Forecast
ADMS	$0.3	$0.3	$0.3
AMI	$2.5	$1.8	$1.4
FAN	$0.3	$0.0	$0.0
FLISR	$0.3	$0.3	$0.4
IVVO	$0.1	$0.2	$0.4
Other	$2.5	$2.0	$1.5
Subtotal in Base Rates (includes all Internal Labor for AMI, FAN, and ADMS)	*$1.8*	*$1.6*	*$1.6*
Subtotal in TCR Rider (excludes Internal Labor for AMI, FAN, and ADMS)[1]	*$4.2*	*$3.0*	*$2.4*
Total	$6.0	$4.6	$4.0

Q. WHAT ARE DISTRIBUTION'S O&M COSTS ASSOCIATED WITH IMPLEMENTING FLISR?

A. Distribution's O&M costs for FLISR will include costs in the following categories: (1) capital support; (2) on-going asset/device support; (3) device replacement; (4) on-going communications network; and (5) training.

Q. WHAT IS INCLUDED IN THE CAPITAL SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities (operations) necessary to safely install new equipment. The Company used actual, average installation times to develop these cost estimates.

Q. WHAT IS INCLUDED IN THE ON-GOING ASSET/DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated the annual support costs by multiplying per-unit support cost estimates by the quantity of devices in service each year.

Q. WHAT IS INCLUDED IN THE COMPONENT REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes material and labor to replace batteries for certain devices on a five-year schedule. The Company estimated these costs as by multiplying per-unit replacement cost by the quantity of devices expected to be in need of battery replacement for each year.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes costs to maintain communications to the field devices. The Company estimated these costs based on historical time to troubleshoot device communication issues and an estimate of the quantity of devices which typically have required such maintenance.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the FLISR program. The Company estimated these costs based on the labor costs of the employees requiring FLISR training (control center, engineering, line crews, etc.) and the time required to train them.

6. Other

Q. WHAT O&M COSTS ARE INCLUDED IN THE OTHER CATEGORY?

A. This category includes Distribution's allocated costs for fleet (vehicles, trucks, trailers, etc.), employee expenses for training and safety meetings, and miscellaneous materials and tools necessary to operate and maintain our electric distribution system.

Q. HOW HAVE YOUR O&M COSTS FOR OTHER BEEN TRENDING?

A. Our Other O&M costs for 2022 to 2024 are lower than our most recent three-year average (2018-2020). This decrease in Other O&M costs is the result of decreases in fleet expenses and materials expenses due to the mixed work reductions previously discussed, as well as the optimization of our Labor splits between capital vs. O&M and increased overtime controls also previously discussed. Both of these initiatives have had a positive impact on both our O&M transportation and material costs. This decrease is also due to a slight increase in first set credits (which reduce our O&M expenses) in these years.

Q. WHAT DO YOU CONCLUDE ABOUT DISTRIBUTION'S O&M COSTS OVERALL?

A. Distribution works diligently each year to minimize increases in our O&M costs. However, in certain years we may experience higher than anticipated O&M costs due to increases in number or severity of severe weather events. During the term of the multi-year rate plan, Distribution's O&M costs will be increasing due to increased investment in capital programs, such as AGIS and Asset Health and Reliability projects, which require increased O&M to implement. In addition, our O&M costs for vegetation management are higher during the multi-year rate plan as we catch up on work that was delayed in 2020. As a result, our O&M cost levels demonstrate a balance between reasonable and prudent management while enabling implementation of necessary capital investments and volume increases in some of our programmatic work activities.

V. ELECTRIC VEHICLE PROGRAMS

A. Overview of the Electric Vehicle Programs

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

A. In this section, I describe the Company's EV programs and discuss the EV capital and O&M budgets for 2022 to 2024.

Q. WHY IS THE COMPANY INVESTING IN EV PROGRAMS?

A. As a Company, we have a groundbreaking objective to reduce carbon emissions 80 percent below 2005 levels by 2030, with a vision to serve customers with 100 percent carbon-free electricity by 2050. With an increasing reliance on renewable generation resources and plans to continue to shift to more renewable generation resources, the electricity sector is no longer the leading producer of greenhouse gases in the United States. Instead, the transportation sector now accounts for the greatest percentage of emissions in both the country and in the state of Minnesota.[16] Our investments in EV programs provide an opportunity to build on our Company's environmental leadership efforts and reduce carbon emissions across both the electricity and transportation sectors. To that end, we have committed to working with public,

[16] For information on greenhouse gas emissions sources in Minnesota, see the 2021 Biennial Greenhouse Gas Emissions Reductions Report, available at https://www.pca.state.mn.us/sites/default/files/lraq-1sy21.pdf.

private, and non-profit partners to achieve a vision to power 1.5 million EVs across the areas served by Xcel Energy's operating companies by 2030, which is 20 percent of all vehicles and is equivalent to a 30-fold increase in electric vehicles.[17] Our goal aligns well with the State of Minnesota's goal of electrifying 20 percent of all light duty vehicles in the state by 2030. The Company has also developed EV programs in response to broader legislative and Commission directives aimed at decreasing the greenhouse gas emissions in the State. The State of Minnesota's leadership in transportation electrification planning is key to unlocking the benefits of these ambitious goals.

The Company is uniquely positioned to help a wide variety of our customers understand the cost savings and emissions reduction benefits of electric transportation, provide customers access to these benefits, and to bring these benefits to our customers rapidly. This proactive role enables the Company to integrate learnings from our EV Program portfolio even in the early stages of this market transformation and into our planning processes. Accomplishing our EV and emissions goals requires thoughtful planning to not only promote the overall adoption of EVs but also help encourage charging of EVs at the beneficial times for our system and all our customers. Additionally, insufficient charging infrastructure is a barrier to transportation electrification, and the Company and others will need to make material investments to address this barrier and reach the state's transportation electrification goals.

[17] *Xcel Energy Electric Vehicle Vision*, XCELENERGY.COM, https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/EV%20Vision%20brochure.pdf.

Q. HOW HAS THE LEGISLATURE ENCOURAGED THE DEVELOPMENT OF EV PROGRAMS?

A. The Minnesota legislature developed statewide greenhouse gas emission goals in Minn. Stat. § 216H.02 that apply to the transportation and electric utility sectors, among others. Additionally, Minn. Stat. § 216B.1614 (EV Statute), which was enacted in 2014, established requirements for utilities to engage in the electrification of the transportation sector. Specifically, the statute states that "each public utility selling electricity at retail must file with the commission a tariff that allows a customer to purchase electricity solely for the purpose of recharging an electric vehicle."[18] The tariff must be available to the residential class. It also authorizes a cost-recovery mechanism to allow utilities to recover costs "reasonably necessary to comply" with the statute, as well as costs related to informing and educating "customers about the financial, energy conservation, and environmental benefits of electric vehicles."[19] The Minnesota Legislature further acknowledged the benefits of EV adoption when it passed the Energy Conservation and Optimization Act (ECO) in May 2021, amending the Minnesota Statutes that govern energy conservation programs and energy savings goals.[20] While increasing the state's and utilities' energy savings goals, ECO will also allow a utility to exclude sales of electricity used for EV charging from the calculation of its energy efficiency savings goal until 2033. The Legislature's determination that increased electric sales resulting from EVs should not result in higher energy savings targets – which might discourage utilities from promoting EVs – reflects its general recognition of the contribution of EV adoption to reducing overall greenhouse gas emissions in the state, among other benefits.

[18] Minn. Stat. § 216B.1614, subd. 2.
[19] *Id.*
[20] Minn. Stat. §§ 216B.2401, 216B.2402, 216B.2403, and 216B.241.

Q. HOW HAS THE COMMISSION ENCOURAGED THE DEVELOPMENT OF EV PROGRAMS?

A. The Commission recognized that the transportation sector now accounts for the greatest percentage of greenhouse gas emissions in Minnesota and has not significantly reduced emissions levels.[21] Increasing the adoption of EVs in Minnesota can help the transportation sector reduce its emissions and the State meet its emissions reduction goals and fight climate change. The Commission has also recognized that utilities are uniquely situated to help drive the electrification of the transportation sector in Minnesota. In furtherance of Minnesota's greenhouse gas emission reduction goals, the Commission ordered utilities to "file proposals, which can be pilots, intended to enhance the availability of or access to charging infrastructure, increase consumer awareness of EV benefits, and/or facilitate managed charging or other mechanisms that optimize the incorporation of EVs into the electric system."[22]

Q. WHAT COMMISSION APPROVALS HAS THE COMPANY RECEIVED REGARDING ITS EV PROGRAMS?

A. To date, the Company has received approval for six EV programs and pilots. These include two residential charging programs, and four EV pilots as summarized below.

- *Residential EV Charging Tariff*: In 2015, the Commission approved the Company's Residential EV Charging Tariff,[23] which provides customers

[21] *In re Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E999/CI-17-879, ORDER MAKING FINDINGS AND REQUIRING FILINGS (Feb. 1, 2019).
[22] *Id.*
[23] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff*, Docket No. E002/M-15-111, ORDER APPROVING TARIFFS AND REQUIRING FILINGS (June 22, 2015).

who opt to have a dedicated service line and meter installed for their EV charger with the opportunity to charge their EV during low cost off-peak hours.

- *Residential EV Accelerate At Home:* In May 2018, the Commission approved the Company's Residential EV Service Pilot,[24] and in October 2020, the Commission approved the Company's request for expansion and conversion to a permanent program, now called EV Accelerate At Home.[25] This program is designed to help customers participate in off-peak rates without the upfront costs of a second service line and meter by measuring EV charging electricity usage for billing purposes with the EV charger itself. It also provides customers the option of having the Company install and pay for the upfront costs of charging equipment (later recovered through an equipment charge).
- *Fleet Charging Pilot:* In July 2019, the Commission approved the Company's Fleet EV Service Pilot[26] designed to encourage the electrification of fleets through Company support and charging infrastructure installation and ownership options. Participation is currently limited to specific entities, such as government entities, non-profit entities, and school districts as well as fleet companies who work with school districts.[27] The pilot provides very limited availability to private entities.

[24] *In the Matter of Xcel Energy's Petition for Approval of a Residential Electric-Vehicle Service Pilot Program*, Docket No. E002/M-17-817, ORDER APPROVING PILOT PROGRAM, GRANTING VARIANCE, AND REQUIRING ANNUAL REPORTS (May 9, 2018).
[25] *See* Commission Order dated October 6, 2020 in Docket No. E002/M-19-559.
[26] *In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Pilot Programs*, Docket No. E002/M-18-643, ORDER APPROVING PILOTS WITH MODIFICATIONS, AUTHORIZING DEFERRED ACCOUNTING, AND SETTING REPORTING REQUIREMENTS (July 17, 2019).
[27] Eligibility in the pilot was expanded by the Commission's August 24, 2021 ORDER MODIFYING EXISTING PROGRAM in Docket Nos. E002/M-18-643 and E002/M-20-745. The Order eliminated

- *Public Charging Infrastructure Pilot:* In July 2019, the Commission also approved the Company's Public Charging Infrastructure Pilot,[28] designed to provide support for installation of public charging infrastructure and community mobility hubs.
- *Residential Subscription Service Pilot:* In October 2019, the Commission approved the Company's Residential Subscription Service Pilot,[29] which provides all the services of the Residential EV Accelerate At Home program and also includes a straightforward monthly subscription fee that allows customers to charge vehicles as much as needed during off-peak periods for a fixed monthly price.
- *Multi-Dwelling Unit Charging Pilot:* In July 2021, the Commission approved the Company's Multi-Dwelling Unit Charging Pilot,[30] designed to provide charging infrastructure to facilitate charging at condos, apartments, and other larger housing sites. The pilot includes options with respect to charging equipment installation and ownership, and provides options for site hosts based on parking setups and equipment needs.

previous restrictions on the number of non-profits, school districts, and fleet operators providing fleet to schools.

[28] *In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Pilot Programs*, Docket No. E002/M-18-643, ORDER APPROVING PILOTS WITH MODIFICATIONS, AUTHORIZING DEFERRED ACCOUNTING, AND SETTING REPORTING REQUIREMENTS (July 17, 2019).

[29] *In the Matter of Xcel Energy's Petition for Approval of a Residential EV Subscription Service Pilot Program*, Docket No. E002/M-19-186, ORDER APPROVING PILOT WITH MODIFICATIONS, AND SETTING REPORTING REQUIREMENTS (Oct. 7, 2019).

[30] *In the Matter of Xcel Energy's Petition for Approval of a Multi-Dwelling Unit Electric Vehicle Pilot Program*, Docket No. E002/M-20-711, ORDER APPROVING PILOT PROGRAM WITH MODIFICATIONS (July 2, 2021).

Q. HAS THE COMPANY REQUESTED APPROVAL OF ADDITIONAL EV OFFERINGS THAT ARE CURRENTLY PENDING BEFORE THE COMMISSION?

A. Yes. In 2020, the Commission requested that utilities in the state bring forward proposals for utility investments that can aid the state in recovering from the economic impact of the COVID-19 pandemic.[31] Our proposal, filed in September 2020, included three new EV-related projects: a rebate program for the purchase of light-duty EVs and electric buses, a project to develop a Company-owned fast-charging network, and the acceleration of electrifying the Company's fleet.[32] Requests for approval of these proposals have been made as part of our Financial Recovery Proposal currently pending before the Commission.[33] In addition, the Company filed a Load Flexibility proposal on February 1, 2021,[34] which included requests for approval of an EV optimization pilot and a school bus vehicle-to-grid demonstration. The Load Flexibility proposal is also currently pending before the Commission. The EV proposals in the Financial Recovery and Load Flexibility petitions are summarized below.

- *EV Purchase Rebate Program:* This proposed program offers rebates for the purchase of electric buses and light duty EVs and requires participants to charge their vehicles on time-varying rates. If approved, the electric bus rebates will spur an expansion of heavy-duty EVs in our service territory. This would enable Metro Transit and other transit providers to materially increase the number of electric buses in their fleet and would help school districts in our service territory add electric

[31] Docket No. E,G999/CI-20-492.
[32] Costs related to electrification of the Company's fleet are not included in the Distribution budget so are not addressed in my Direct Testimony. Costs related to electrification of Xcel Energy's fleet are discussed in the Direct Testimony of Company witness Mr. Husen.
[33] EV proposals are being considered in their own docket, Docket No. E002/M-20-745.
[34] Docket No. E002/M-21-101.

school buses to their fleets. The light-duty rebates as proposed will be available to residential customers as well as fleet operators.

- *Public Fast Charging Network Program:* In addition to the work under our approved Public Charging Pilot described above, the Company proposes to build, own, and operate a network of about 20 direct-current fast charging (DCFC) stations. Under this proposal, stations would be targeted to parts of our service territory that are currently underserved by existing fast charging offerings. This proposal is intended to start helping address the current public charging infrastructure gap in our service territory (including in rural areas), provide access to charging for those who cannot charge at home or at their business, and enable intra-community transportation.
- *EV Optimization Pilot:* This pilot will study the management of the grid impacts of electric vehicles by working with customers to provide schedule options for their daily EV charging. The schedule options ensure charging occurs outside the Company's system peak and are designed to stagger charging times to avoid demand spikes during the off-peak period.
- *School Bus Vehicle-to-Grid (V2G) Demonstration:* This demonstration project will study the value of V2G applications for the distribution grid. The project is designed to allow the Company to dispatch bus batteries during summer system peaks, for use during critical times or when a strain on the power grid is expected. Various applications will be tested and impacts to the distribution system will be measured and verified. The project will also present opportunities to test renewables integration by charging batteries during periods of excess wind or excess solar generation on the grid.

Q. WHAT EV PROGRAM COSTS IS THE COMPANY SEEKING TO RECOVER IN THIS RATE CASE?

A. The Company is seeking to recover capital and O&M expenses for 2022 to 2024 associated with each of the programs and pilots discussed above. As noted, these programs and pilots have either been approved by the Commission or are currently pending Commission approval. All EV Program capital is part of the Company's Distribution capital budget, and a portion of EV Program O&M is part of the Distribution O&M budget, namely, the O&M associated with EV chargers and EV supply infrastructure. The majority of EV Program O&M is part of the Customer and Innovation organization's budget and not covered in detail in my testimony. The Company's budgets in this rate case reflect the capital and O&M costs associated with the EV pilots and programs. As the Company is in the relatively early stages of its EV Programs, we continue to work to align our budgeting approach with the needs of both approved and proposed EV Programs.

Additionally, the Commission has previously approved deferral of certain EV program O&M and depreciation expense, consistent with the EV statute. The Company is requesting recovery of these deferred costs for prior years in this rate case. Costs for EV education and outreach that are incremental to the budget will continue to be included in our established EV cost tracker. Treatment of the EV tracker costs for prior years is discussed in the testimony of Mr. Halama.

The Company is also seeking to recover capital and O&M expenses for 2022 to 2024 associated with expanding some of these pilots into permanent programs, and expansion of certain proposals currently pending approval that go beyond the scope of the petitions in those dockets. The Company anticipates that it will seek approval for these expansions in order to meet customer demand during the multi-year rate plan period, and the Company has discussed the possibility of expansions of pilot programs in our 2021 Transportation Electrification Plan (TEP).[35] I discuss the budget assumptions for these expansions in the individual program sections later in my testimony.

In addition, the Company is seeking to recover capital and O&M expenses for 2022 to 2024 to support a Partnership, Research, and Innovation (PRI) initiative to support its EV programs and further the Company's understanding of emerging issues related to transportation electrification.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ABOUT THE PRI INITIATIVE?

A. Yes. The Company recognizes that the transportation electrification landscape is evolving as new technologies, including vehicles, charging equipment, and software, become increasingly viable and ready for deployment. Objectives for our PRI initiative include making it easier for customers to access electricity as a transportation fuel, minimizing system costs and increasing environmental benefits for charging, gaining insights to help inform future TEPs, and exploring any gaps not addressed in the Company's current transportation electrification programs. The Company plans to solicit input on and develop several projects during the multi-year rate plan period stemming from our research and experience to date, stakeholder input, and customer engagement. Xcel Energy's Colorado subsidiary has a similar initiative, which is currently considering project ideas, including concepts that support reducing DCFC

[35] Transportation Electrification Plan, Docket No. E999/CI-17-879 (June 1, 2021).

charging costs through energy storage and electrification of medium-duty special purpose fleets. Additional areas of focus could include charging optimization solutions for fleets and electrification of shared mobility. These potential focus areas are examples to illustrate the purpose of the PRI initiative. The Company intends to solicit input from stakeholders prior to pursuing specific PRI projects. The Company believes that there will be many opportunities to learn through the PRI initiative and that it is important to conduct these types of exploratory projects not just in Colorado, but also Minnesota, which would greatly benefit from these learnings directly as well. Plus, the PRI provides an opportunity to partner with local public and private sector entities who may be able to bring additional funding and/or expertise to specific projects.

Q. YOU MENTIONED THAT THE DISTRIBUTION AREA BUDGET DOES NOT INCLUDE ALL OF THE EV PROGRAM COSTS IN THIS CASE. CAN YOU ELABORATE?

A. Yes. The Distribution budget includes the majority of the EV program costs. This includes all of the EV capital costs, along with associated O&M expenses related to EV chargers and EV supply infrastructure equipment. I support these costs for the MYRP period as part of my testimony.

Other EV program O&M costs for the MYRP period are included in the Customer and Innovation business area budget. These costs are related to program management, IT, program evaluation, stakeholder engagement, awareness, education, and outreach. For convenience, I have included high-level discussion of these costs in my testimony.

Q. CAN YOU EXPAND ON THE COMPANY'S GENERAL APPROACH TO BUDGETING FOR EV PROGRAMS IN THIS CASE?

A. Yes. The EV budgets in this case are based on our current expectations for program implementation and expansion over the term of the multi-year rate plan. As noted above, some of these costs are related to expansion of current or pending programs and pilots in the coming years, and the PRI portion of the budget is for a limited number of EV initiatives that are not yet specifically identified or fully developed. While the Commission will continue to separately review and approve all new and expanded EV programs for customers, building these anticipated costs into our base rate budgets provides the Company some flexibility to adapt and respond to customer interest, technology advancements, or market developments. Further, budgeting in this way minimizes the need for the Company to request deferral of costs associated with new EV programs or initiatives that are in the public interest or designed to support public policy goals. This is also consistent with a prior Commission Order on our Fleet and Public Charging pilots. In approving the Company's request for deferral of costs related to those pilots, the Commission also recognized the need to develop a more comprehensive strategy for encouraging utilities to innovate within the regulatory structure. For that reason, the Commission required the Company to address in its next rate case how it intended to handle and budget for future pilots.[36] While not a requirement in this case, the Company is continuing to budget for EV initiatives with the intent to minimize the need for future deferral requests.

[36] Commission Order dated July 17, 2019, Order Point 14, Docket No. E002/M-18-643.

Q. WHAT ARE DISTRIBUTION'S OVERALL CAPITAL ADDITIONS FOR THESE EV PILOTS AND PROGRAMS OVER THE TERM OF THIS MULTI-YEAR RATE CASE?

A. Table 36 below provides the capital additions for the Company's EV programs that are included in this rate case.

Table 36

Overall EV Program Distribution Capital Additions

(Dollars in Millions)

Program or Pilot	2022	2023	2024
Residential EV Programs	$0.8	$1.1	$1.6
Fleet & Public Charging Pilots	$9.5	$13.1	$15.7
Multi Dwelling Unit Pilot	$1.6	$1.2	$1.9
EV Purchase Rebates & Fast Charging Network	$66.3	$50.8	$37.2
Partnership, Research, and Innovation – Capital	$0.8	$3.5	$4.0
Total	**$79.1**	**$69.7**	**$60.5**

Q. WHAT ARE THE EV O&M COSTS INCLUDED IN THE DISTRIBUTION BUDGET OVER THE TERM OF THIS MULTI-YEAR RATE CASE?

A. Table 37 below provides the O&M expense budgets for the Company's EV Programs that are included in the Distribution budget in this rate case. As noted earlier, most of the EV Programs' O&M costs are included in the Customer and Innovation organization's budget and are not included below.

Table 37

EV Program Distribution O&M Expenses

(Dollars in Millions)

NSPM – Total Company Electric (Dollars in Millions)	2022 Budget	2023 Budget	2024 Budget
O&M Expenses	$0.5	$0.7	$0.8

These are the EV Program O&M costs included in the Distribution budget. The EV Program O&M costs in the Distribution budget include anticipated costs to maintain charging equipment and EV supply infrastructure for all EV programs and pilots at a rate of three percent of the capital costs for that equipment and infrastructure.

Q. DOES THE COMPANY EXPECT ACTUAL COSTS TO EXACTLY MATCH THE MYRP BUDGETED AMOUNTS PRESENTED IN THIS TESTIMONY?

A. No. As discussed earlier in my testimony, actual expenditures may differ from budgeted amounts due to changing circumstances or specific events that occur during a multi-year rate plan period. Where the Company intends to expand the scope of an EV pilot or program with a defined scope, the implementation details, timing, and budgets for the expansions will require Commission approval in separate dockets, where stakeholder input will also be considered in the Commission's final determinations. As such, actual investments and expenditures may be different than the amounts included in our MYRP budgets in this case.

Further, with continuing changes in the EV landscape, additional stakeholder input, or as a result of Commission direction, it is possible that the Company may propose additional pilots or offerings during the MYRP period.

Q. HOW DOES THE COMPANY PROPOSE TO MANAGE ANY CHANGES TO ACTUAL EV PROGRAM EXPENDITURES THAT MAY BE REQUIRED DURING THE MYRP PERIOD?

A. As discussed earlier in my testimony, Electric Vehicle Programs is one of the eight capital budget groupings in the Distribution area. Management of any changes to Distribution's capital investments over the course of the MYRP are discussed in Section III(B). Section IV(B) describes how the Distribution business unit – like other business areas of the Company – manages changes to O&M expenditures that may be required in a particular area by re-prioritizing and reallocating budgeted O&M dollars while still operating within the overall Distribution O&M budget.

Q. DOES THE COMPANY ANTICIPATE INCURRING ADDITIONAL EV PROGRAM COSTS THAT ARE NOT INCLUDED IN THIS RATE CASE?

A. Yes, the Company may incur additional EV Program costs that are not included in the budgets presented in this case. These additional costs would be related to capital investments and O&M expenses for 2022 to 2024 associated with EV pilot or program proposals that have not been proposed in detail to the Commission and/or are beyond what is currently contemplated under the PRI budget. The Company does anticipate that it may propose additional programs or pilots during the multi-year rate plan period. This may include several new potential programs based on concepts highlighted in the Company's 2021 TEP.[37] To the extent the Company proposes and the Commission approves new EV pilots and programs that are not included in the capital and O&M

[37] The EV program concepts highlighted in the 2021 TEP that the Company is currently exploring include a successor to the Public Charging Pilot, support for community EV planning, street-side charging, segmentation and targeting/EV charging detection, opportunities to lower the upfront cost of residential wiring for EV charging, and streamlining available home charging offerings. Cost related to potential initiatives in these areas are not included in the multi-year rate plan budget.

budgets proposed in this MYRP, cost recovery options would be reviewed in those proceedings. For certain costs, the Company may propose use of the existing EV tracker established under the EV Statute.

B. Commission-Approved EV Programs

1. Residential EV Programs

Q. PLEASE DESCRIBE THE RESIDENTIAL EV ACCELERATE AT HOME PROGRAM.

A. The Company launched its initial Residential EV Service Pilot in August 2018 to study the effectiveness of offering residential customers a home charging product without the need to install a second meter. The pilot lowered potential barriers to EV ownership and participation in time-varying rates by reducing customers' upfront costs related to charging equipment installation and the installation of a second meter. Through the pilot, the Company coordinated the installation of level 2 electric vehicle charging equipment at a customer's home to facilitate faster, convenient EV charging. The charging equipment provides billing quality energy usage data. This allows participating customers to take service under a TOU energy rate that incentivizes participants to schedule their charging during off-peak periods. Due to the immediate interest in our Residential EV Service Pilot, the Company quickly developed a plan to expand the pilot into a permanent offering – now known as the EV Accelerate At Home Program. The Commission approved this as a permanent program in October 2020. We launched this program in December 2020, and all customers that were participating in the Residential EV Service Pilot were transitioned to the permanent offering.

Q. PLEASE DESCRIBE THE RESIDENTIAL EV SUBSCRIPTION SERVICE PILOT.

A. This pilot provides customers with all the services of the Residential EV Accelerate At Home program, but instead of the traditional time-of-use rate design approach, the pilot incorporates a straightforward flat monthly subscription fee that makes the cost of charging an EV easy to understand. This program was launched in early 2020. The launch of this pilot was heavily impacted by the onset of the COVID-19 pandemic. To address this and maintain the ability to gather learnings from the pilot, the Company requested, and the Commission approved, modifications to the pilot in September 2020.[38]

Q. WHAT ARE THE BENEFITS OF THE COMPANY'S RESIDENTIAL EV OFFERINGS?

A. There are several benefits of the Company's Residential EV offerings which include, (1) reducing the initial barriers of entry inherent in EV charging rate adoption, (2) improving customers' experiences with EV charging; (3) increase interest and awareness around EVs leading to higher adoption rates for EVs; (4) ensure safe and reliable service consistent with our standards through the provision of a tailored EV service platform.

Q. WHAT ARE THE CAPITAL COSTS FOR THESE RESIDENTIAL EV OFFERINGS THAT ARE INCLUDED IN THE COMPANY'S RATE REQUEST?

A. Capital investments for the residential EV offerings are for the purchase and installation of the charging equipment. Each residential program offers customers a choice of chargers from a pre-approved list. The Company then coordinates installation of charging equipment using contractors selected

[38] *In the Matter of Xcel Energy's Petition for Approval of Modifications to the Residential EV Subscription Service Pilot Program*, Docket No. E002/M-19-186, ORDER (September 28, 2020).

through a competitive process. The capital additions for each year of the MYRP term are provided in Table 38 below.

Table 38
EV Residential Pilots and Programs
Capital Additions ($ in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
EV Residential Capital Additions	$0.8	$1.1	$1.6

Q. WHAT TYPES OF O&M EXPENSES ARE ASSOCIATED WITH THE EV RESIDENTIAL OFFERINGS?

A. The Distribution O&M costs are associated with maintenance of the charging equipment. Other O&M costs for these pilots and programs that are not included in the Distribution budget include costs for program administration, IT, and billing.

Q. HOW DOES THE COMPANY RECOVER THE COSTS OF THE EV RESIDENTIAL OFFERINGS?

A. The capital and O&M costs associated with charging equipment installation and administration of the EV Residential pilots and programs are recovered from program participants through monthly charges on participating customers' bills.

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE EV RESIDENTIAL OFFERINGS?

A. The capital budget is based on the number of customers currently participating, and anticipated to participate, in the Residential offerings, as well as our prior experience with residential EV services and level of customer interest in these offerings. Budget amounts were determined based on charging equipment contracts, where vendors were selected as a result of extensive testing and selection work completed for our Residential EV Service Pilot. The nine installation contractors now used by the Company were selected through a request for proposal process for the launch of the permanent offer. The EV Subscription Service Pilot has Commission approval for a limited budget through 2024. Pending customer demand and the overall success of the pilot, the Company may request expansion of this pilot and to transition this pilot into a permanent program prior to 2024.

Q. HOW WAS THE DISTRIBUTION O&M BUDGET DEVELOPED FOR THE EV RESIDENTIAL OFFERINGS?

A. The O&M budget is based on the number of customers currently participating, and anticipated to participate, in the Residential offerings, as well as our operating experience with the initial EV Residential Service Pilot. The Distribution Budget includes anticipated costs to maintain charging equipment at a rate of approximately three percent of program capital costs.

2. Fleet and Public Charging Pilots

Q. PLEASE DESCRIBE THE FLEET CHARGING PILOT.

A. The Company is currently operating a Fleet Charging Pilot, which was launched in 2019. As a part of this pilot, we are studying the effectiveness of Company investment in EV chargers and EV supply infrastructure for fleet operators. By lowering upfront costs, the pilot aims to facilitate greater adoption of electric fleet vehicles by fleet operators in our service territory. The pilot will also study how charging behavior and utilization of time-of-use

(TOU) rates will impact fleet operators and the electrical grid. The Company plans to operate the pilot over three years and will focus on serving charging needs for light-duty vehicles and buses. The pilot was launched with one initial participant, Metro Transit. We expect to add projects to support additional participants soon, including the Minnesota Department of Administration.

Q. WHAT ARE THE BENEFITS OF THE FLEET EV SERVICE PILOT?

A. The Company proposed the fleet market segment for piloting new services for transportation electrification because of:

- The diversity of vehicles – the fleet EV pilot creates opportunities to learn more about the challenges involved in electrifying a variety of vehicle types;
- Value focus – motivated more by project economics and life-cycle costs than residential customers, fleet operators will be more likely to quickly convert significant portions of their fleets to EVs once the business case is established;
- Motivation to reduce greenhouse gas emissions and improve air quality – fleet operators have been first movers in utilizing EVs for environmental and economic reasons, and will be likely to convert their fleets to EVs more rapidly with pilot program support; and
- The volume of vehicles to enable larger strides toward transportation electrification – many of the Company's customers have fleets of hundreds or thousands of vehicles and may be swayed to electrify their fleets by the pilot's improved economics and support for first-movers.

The pilot program will initially help address some of the barriers to EV adoption in the fleet market segment. It will also allow a deeper understanding of the EV system benefits and how to support transportation electrification costs, especially in the fleet market segment, and will provide a platform for the Company to evaluate models for offering EV services at scale as the market matures and grows. The information learned through the pilot will also be available to help the Commission, other utilities, and stakeholders consider other EV offerings and program designs in Minnesota.

Q. PLEASE DESCRIBE THE PUBLIC CHARGING PILOT.

A. Similar to the Fleet Charging Pilot discussed above, our Public Charging Pilot is intended to help address the public charging infrastructure gap through support for EV supply infrastructure for public charging, but we are also seeking to learn more about administering these types of services to help inform what a permanent offering could look like. We will be discussing with customers and stakeholders how this model, or other approaches, could scale and help ensure there is enough public fast charging infrastructure to support EV adoption.

Through the Public Charging Pilot, Xcel Energy will install, own, and maintain EV supply infrastructure for developers of public direct current fast-charging stations within the Company's service territory. Unlike the Fleet EV Service Pilot, the Company would not own or maintain any charging equipment. In addition, the Company will partner with the cities of Saint Paul and Minneapolis to support installation of community mobility hubs, for which the cities have selected HOURCAR as the anchor tenant. The cities have obtained Federal Congestion Mitigation Air Quality funds to purchase vehicles, chargers, and operating services for this new mobility service. These charging hubs may be utilized by car-sharing services, transportation network companies (e.g., Uber and Lyft), and the public, including customers who do not have EV charging capabilities at home. The Company is continuing to recruit customers and work with partners at the cities of Minneapolis and Saint Paul to identify potential charging sites. The Company estimates that this pilot will facilitate the installation of approximately 350 charging ports.

Q. WHAT ARE THE BENEFITS OF THE PUBLIC CHARGING PILOT?

A. This pilot program will seek to leverage private and public funding, including Minnesota's Diesel Replacement Program funded by the Volkswagen Environmental Mitigation Settlement and administered by the Minnesota Pollution Control Agency, and help reduce a significant barrier to EV adoption—limited availability of public charging for EVs—by adding public EV charging stations along corridors and at charging hubs. The public charging stations will support longer distance driving, address range anxiety, and provide charging solutions for those who are not able to charge at home. This should encourage greater adoption of EVs within the state, which will reduce greenhouse gases and improve air quality.

We are also exploring further ways to grow public charging in Minnesota. Utilities have vast experience with building out infrastructure and working these installations beneficially into the electrical grid; utilities can also play a role connecting the dots and bringing interested parties together to consider various options to meet public charging needs. Insufficient public fast charging infrastructure is a barrier to transportation electrification, and it may be necessary for utilities to play a stronger role to ensure public charging needs are met.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE FLEET EV SERVICE PILOT AND PUBLIC CHARGING PILOT BUDGETS?

A. Fleet EV Service Pilot capital expenses fall into three categories: EV service connection infrastructure, EV supply infrastructure and EV charging equipment. Service connection infrastructure covers all equipment on the utility's side of the traditional point of connection, which includes necessary transformer upgrades, pads, poles, new service conductors, as well as metering equipment for EV charging separate from any existing service at the site. EV supply infrastructure includes new panels, conduit, and wiring up to the charger. EV charging equipment is the charger itself. For the Public Charging Pilot, both EV service connection infrastructure and EV supply infrastructure are included, but site hosts and developers are responsible for the procurement, installation, and maintenance of charging equipment. The capital additions for each year of the multi-year rate plan term are provided in Table 39 below.

Table 39

EV Fleet and Public Charging Pilots – Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
EV Fleet and Public Charging Capital Additions	$9.5	$13.1	$15.7

Q. HOW WERE THE CAPITAL BUDGETS DEVELOPED FOR THE FLEET AND PUBLIC CHARGING PILOTS?

A. In the development of these capital budgets, we relied on several sources, including third-party estimators for a limited number of sites, internal subject matter experts to estimate distribution costs in various scenarios, and a third-party consultant to help benchmark our numbers by identifying and sharing studies focused on EV charging infrastructure costs and utility proposals and reports. The budgets are also based on the number of customers currently participating, and anticipated to participate, in the Fleet and Public Charging pilots. The Company acknowledges that customer participation in the Fleet and Public charging pilots to date has been slower than originally anticipated; however, the Commission recently approved the Company's request to expand eligibility for the Fleet Charging pilot to address this participation gap.[39] The pilots as originally filed proposed budgets through 2022; and the budgets included in this rate case include the pilot budgets through 2022 as well as expansion of these pilots after 2022. The Company plans to undertake targeted efforts to increase participation in these pilots in 2022 and gauge additional customer demand in the fleet and public charging market segments for EV Program support beyond the scope of the current Fleet and Public Charging pilots. The Company anticipates increasing interest from customers eligible for the Fleet Service pilot, as governmental entity customers in particular are increasingly looking to plan for fleet electrification. Pending customer demand, the Company plans to request expansion of these pilots and to transition these

[39] *In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Pilot Programs*, Docket No. E002/M-18-643, ORDER MODIFYING EXISTING PROGRAM (August 24, 2021)

pilots into standing programs. Budget amounts associated with an expansion are included starting in 2023.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE FLEET EV SERVICE PILOT?

A. Yes. The O&M expenses for the Fleet EV Service Pilot fall into the following categories: advisory, analytics, and outreach services; installation management; program management; and IT. There are also O&M expenses related to the maintenance of infrastructure and equipment, and charging network costs.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE PUBLIC CHARGING PILOT?

A. Yes. The O&M expenses for the Public Charging Pilot fall into the following categories: installation management, program management, and IT. There are also additional O&M expenses related to infrastructure maintenance, and marketing, education, and outreach.

Q. WHICH OF THOSE O&M EXPENSES ARE INCLUDED IN THE DISTRIBUTION O&M BUDGET FOR THE FLEET AND PUBLIC CHARGING PILOTS?

A. O&M expenses related to maintenance of EV supply infrastructure and charging equipment are included in the Distribution EV Program budget.

Q. HOW WERE THE O&M BUDGETS FOR THE FLEET AND PUBLIC CHARGING PILOT DEVELOPED?

A. The O&M budgets are based on the number of participants and charging sites expected under these pilots, as well as our experience with administration of these programs. For the Fleet Pilot, the Distribution O&M budgets are based on the number of partners expected to enroll in this pilot as well as our initial work with Metro Transit prior to pilot launch. For the Public Charging Pilot, the Distribution O&M budget is based on the number of sites expected under the pilot as described above. Budget amounts were determined based on internal subject matter experts to estimate distribution costs in various scenarios and reflect a rate of three percent of the capital costs for charging equipment and EV supply infrastructure.

Q. HOW DO THESE BUDGETS COMPARE TO THE BUDGETS PROVIDED TO THE COMMISSION IN DOCKET NO. E002/M-18-643?

A. The budget for the Fleet EV Service Pilot remains the same, with implementation over a three-year period, which would end in 2022. Beyond that, our budget assumes the Company will continue to support fleets electrification and public charging beyond the pilot period. The future permanent fleet and public charging offerings will be developed based upon learnings from the pilot, and will need to be approved by the Commission prior to launch.

3. Multi-Dwelling Unit EV Service Pilot

Q. PLEASE DESCRIBE THE MULTI-DWELLING UNIT EV SERVICE PILOT.

A. In May 2021, the Commission voted to approve our Multi-Dwelling Unit (MDU) EV Service Pilot. This pilot is intended to meet a need for charging options at MDU buildings, which have unique barriers that have made them difficult to serve with EV charging access. The pilot is expected to launch by the end of 2021. Through the pilot, the Company will install, own, and maintain EV supply infrastructure and EV charging infrastructure to be used by residents of MDUs. The pilot is designed with optionality related to parking types and charging equipment ownership that will allow site owners to customize their participation based on their needs. The customer charge will vary based on the options chosen, but all sites will be required to take electric service on an available time-varying rate.

Q. WHAT ARE THE BENEFITS OF THE MDU EV SERVICE PILOT?

A. Through the MDU EV Service Pilot, the Company seeks to address the market barriers to installing EV charging at MDUs, assess the financial support needed to encourage accelerated installation of EV charging in MDUs, and increase interest and awareness around the benefits of EVs to encourage higher adoption rates for EVs. In addition, requiring a time-varying rate will further the Company's goal of promoting EV charging at times that make efficient use of the power grid by avoiding system peaks and integrating more renewable energy production.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE MDU EV SERVICE PILOT BUDGET?

A. Capital costs for the MDU EV Service Pilot include costs of the EV service connection and EV supply infrastructure (described in detail earlier), the EV charging equipment, and the IT system for the program. The capital additions for each year of the multi-year rate plan term are provided in Table 40 below.

Table 40

MDU EV Service Pilot – Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
MDU EV Service Pilot	$1.7	$1.2	$1.9

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH MDU EV SERVICE PILOT?

A. Yes. The O&M expenses for the MDU EV Service Pilot fall into the following categories: installation management, advisory services and outreach, pilot management. There are also O&M expenses related to the maintenance of EV supply infrastructure and charging equipment. O&M expenses related to maintenance of EV supply infrastructure and charging equipment are included in the Distribution budget.

Q. HOW WILL THE COMPANY RECOVER THE COSTS OF THE MDU EV SERVICE PILOT?

A. Capital costs, including EV service connection, EV supply infrastructure, and EV charging equipment assets are approved to be recovered in rate base. O&M costs, such as advisory services, education and outreach, have been approved for deferral in the established EV tracker account. The capital and O&M costs associated with charging equipment installation and maintenance are recovered from program participants through monthly charges on participating customers' bills.

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE MDU EV SERVICE PILOT?

A. Similar to the Fleet EV Service and Public Charging pilots, we relied on several sources, including third-party estimators and internal subject matter experts to estimate distribution costs in the various types of participation scenarios to meet the anticipated level of customer interest. The MDU EV Service Pilot as approved includes a budget through 2023. Pending customer demand, the Company plans to request expansion of this pilot beyond 2023 and to transition this pilot into a permanent program. Budget amounts associated with an expansion are included starting in 2024.

Q. HOW WAS THE O&M BUDGET DEVELOPED FOR THE MDU EV SERVICE PILOT?

A. The O&M budget is based on the number of sites expected under the pilot as well as prior experience with administration of EV programs. Budget amounts were determined based on internal subject matter experts to estimate distribution costs in various scenarios and reflect a rate of three percent of the capital costs for charging equipment and EV supply infrastructure.

C. Proposed EV Programs and Pilots Pending Commission Approval

1. EV Purchase Rebate and Public Fast Charging Programs

Q. PLEASE DESCRIBE THE EV PURCHASE REBATE PROGRAM.

A. The EV Purchase Rebate is intended to provide rebates to customers for the purchase of light-duty EVs and electric buses and their participation in a managed charging program tariff. This large rebate effort is intended to kick-start the growth of EV adoption in Minnesota. The rebate would be available to residential and commercial customers, nonprofits, and government entities interested in increasing their electrified fleet.

Q. PLEASE DESCRIBE THE COMPANY'S PUBLIC FAST CHARGING PROPOSAL.

A. The Public Fast Charging proposal involves the Company developing, installing, owning, and operating a network of public fast charging stations. Through this plan, the Company will install 21 DCFCs throughout our service area. We plan to target more remote parts of our service area that are not currently served by the existing fast charging market. These charging stations will serve as a vital resource to encourage increased EV adoption, as access to public charging can lower one of the biggest barriers preventing transportation electrification – range anxiety.

Q. WHAT ARE THE BENEFITS OF THE EV PURCHASE REBATE AND PUBLIC FAST CHARGING PROGRAMS?

A. The benefits of both of these proposals include boosting Minnesota's economy with indirect creation of new jobs, as well as helping further the adoption of EVs in the State, benefiting EV drivers, ratepayers, and society broadly.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE EV PURCHASE REBATE BUDGET?

A. We have included $150 million in rebates in the capital budget for this case. This amount matches our initial rebate amount in the COVID-19 Financial Recovery Proposal. This includes rebate payments for both light-duty vehicles and electric buses, both transit and school. That docket is currently pending before the Commission. In that docket, stakeholders expressed interest in an initial, smaller rebate program, and the Company did not object to a smaller initial program size. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket. However, pending customer demand, the Company intends to request expansion of the EV Purchase Rebate program in the future, and costs associated with an expansion are included in the budget starting in 2024.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE PUBLIC FAST CHARGING PROGRAM BUDGET?

A. We have included approximately $5 million in capital investments related to the Public Fast Charging Program in the capital budget in this case. These investments include 21 DCFC public fast charging stations and the associated necessary service connection equipment, which includes any necessary transformer upgrades, pads, poles, new service conductors, as well as metering equipment to monitor station energy usage. Additionally, the Company will install, own, and maintain the EV supply infrastructure including new panels, conduit, and wiring up to the charger as well as any necessary civil construction work in compliance with state and local codes. Pending customer demand, the Company intends to request expansion of the Public Fast Charging Program, and costs associated with an expansion are included in the budget starting in 2024.

Q. WHAT ARE THE TOTAL CAPITAL INVESTMENTS FOR THESE PROGRAMS DURING THE MULTI-YEAR RATE PLAN TERM?

A. The capital additions for each year of the multi-year rate plan term are provided in Table 41 below.

Table 41

EV Purchase Rebate and Public Charging Programs – Capital Additions (Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2022 Budget	2023 Budget	2024 Budget
EV Purchase Rebate and Public Charging Programs	$66.2	$50.8	$37.2

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE EV PURCHASE REBATE AND PUBLIC FAST CHARGING PROGRAMS?

A. These programs were developed to address a direct call from the Commission to present proposals that could spur financial recovery in response to the COVID-19 pandemic. As such, the budgets for these programs, especially the EV Rebate program, were designed with that goal in mind. An EV rebate budget of $150 million would allow us to drive EV purchases and spur rapid growth in transportation electrification—upwards of 20,000 light-duty vehicles and over 100 electric buses. The amount of transit bus rebates was developed in consultation with Metro Transit, to consider both the cost of a new electric bus and the amount of infrastructure costs needed to support charging of those vehicles.

For the Public Fast Charging Program, the budget is based on the costs of installing the 21 new DCFC charging stations and the related necessary service connections, metering equipment, and other capital costs. The budgeted amount is based on Company-expertise on the cost of related work.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE EV PURCHASE REBATE AND PUBLIC FAST CHARGING PROGRAMS?

A. O&M costs for the EV Purchase Rebate Program are included in the Customer and Innovation budget. For the Public Fast Charging Program, O&M expenses related to installation, operation, and maintenance of the fast chargers are included in the Distribution budget, and program administration costs are included in the Customer and Innovation budget.

Q. HOW WERE THE O&M BUDGETS DEVELOPED FOR THESE PROGRAMS?

A. The O&M budget is based on the number of customers anticipated to participate in the EV Purchase Rebate Program, as well as our operating experience with similar programs. The O&M budget for the Public Fast Charging Program is based on Company-expertise on the O&M costs of similar work.

2. Load Flexibility EV Proposals

Q. PLEASE DESCRIBE THE EV OPTIMIZATION PILOT.

A. The Company's EV Optimization Pilot is included as part of our Load Flexibility proposal, currently pending approval by the Commission. With this pilot, the Company seeks to study the management of grid impacts of EVs by working with customers to schedule daily EV charging based on the customer's selection of a preferred schedule. The schedule options ensure charging occurs outside of the Company's system peak, and will allow the Company to effectively stagger charging during those off-peak hours. This proposed offering is for residential customers and is also offered for commercial customers with light-duty fleets using the same or similar vehicle and charging station equipment as residential customers.

This offering is designed to complement our existing EV service offerings by providing an option for customers who wish to bring their own charging equipment to receive benefits for reducing the impact of EV charging on the grid. The EV Optimization Pilot is designed to provide a bill credit for participating customers. Participating customers will continue to be charged for service according to their applicable base rate tariff, and participation is available to eligible customers taking service under several different base rate tariffs, both EV service tariffs and general service tariffs. As noted above, all charging will occur off-peak and as scheduled by the Company.

Q. WHAT ARE THE BENEFITS OF THE EV OPTIMIZATION PILOT?

A. Through the EV Optimization Pilot, the Company seeks to provide a widely available option for EV customers to participate in managed charging and reduce the impacts of EV charging on the bulk electric and distribution systems. This pilot will also measure customer interest and participation in this managed charging offering and evaluate the grid benefits of managed charging to support the evolution of the Company's demand management programs and rates, particularly related to EVs.

Q. ARE THERE CAPITAL INVESTMENTS INCLUDED IN THE EV OPTIMIZATION PILOT BUDGET?

A. No. This pilot is a managed charging offering for customers who already have EVs, and thus does not require Company installation of additional EV service infrastructure or EV charging equipment.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE EV OPTIMIZATION PILOT?

A. Yes. The O&M costs for this pilot include costs for pilot management and customer service, outreach efforts, measurement and verification, and customer bill credits.

Q. ARE THE O&M EXPENSES FOR THE EV OPTIMIZATION PILOT INCLUDED IN THE DISTRIBUTION O&M BUDGET?

A. No. These costs are not included in the Distribution O&M budget. The Company has requested deferred accounting treatment for these costs and this request is currently pending Commission approval in the Load Flexibility proceeding.

Q. HOW WAS THE O&M BUDGET DEVELOPED FOR THE EV OPTIMIZATION PILOT?

A. The O&M budget was developed based upon estimated customer participation and the Company's prior experience with EV customer service and program administration.

Q. PLEASE DESCRIBE THE SCHOOL BUS V2G DEMONSTRATION.

A. The Company's School Bus V2G Demonstration project is included as part of our Load Flexibility proposal, currently pending approval by the Commission. With this project, the Company seeks to study the value of V2G applications for the distribution grid. The project will dispatch bus batteries during summer system peak events. The Company will rely on bus batteries during critical times or when a strain on the power grid is expected. To ensure battery availability, we will expect operators to park their buses and plug them into the charging station at their facility at pre-determined times. During the demonstration, various applications will be tested such as measuring and verifying the effects of V2G on the distribution system. The project also presents opportunities to test renewables integration by charging batteries during periods of excess wind or excess solar generation on the grid.

Q. WHAT ARE THE BENEFITS OF THE SCHOOL BUS V2G DEMONSTRATION?

A. The demonstration project will provide the opportunity to test various applications, as described above, to provide learnings related to the effects of V2G on the distribution system the potential for renewables integration by charging batteries during periods of excess wind or excess solar generation on the grid.

Q. ARE THERE CAPITAL INVESTMENTS INCLUDED IN THE SCHOOL BUS V2G DEMONSTRATION?

A. Yes. Capital costs include charging equipment and bus rebates and have been proposed in our COVID-19 Financial Recovery filing.[40]

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE SCHOOL BUS V2G DEMONSTRATION?

A. Yes. The O&M costs for this pilot include program administration and third-party evaluation. The Company has requested deferred accounting treatment for these costs and this request is currently pending Commission approval in the Load Flexibility proceeding. These costs are not included in the Distribution O&M budget.

Q. HOW WAS THE O&M BUDGET DEVELOPED FOR THE SCHOOL BUS V2G DEMONSTRATION?

A. The O&M budget for this project was determined based upon the estimated number of V2G demonstration projects and costs for program administration and evaluation.

[40] Docket No. E002/M-20-745.

D. Partnership, Research, and Innovation Initiative

Q. PLEASE DESCRIBE THE PARTNERSHIP, RESEARCH, AND INNOVATION INITIATIVE.

A. The landscape for transportation is continuing to evolve as new technologies are being developed and brought to market, including new types of vehicles, new charging approaches, and software platforms. These technologies could help improve the customer experience and provide benefits to the grid. The Partnership, Research, and Innovation (PRI) Initiative intends to bring forward future projects that aim to increase and broaden access to electricity as a transportation fuel, minimize system costs, and increase benefits of electric transportation, and inform future EV programs.

Q. WHAT TYPES OF WORK WOULD THE COMPANY ENGAGE IN UNDER THE PRI INITIATIVE?

A. The PRI budget is intended to provide flexibility to fund a limited number of projects that are identified during the multi-year rate plan period. Potential projects include those that support reducing DCFC charging costs through energy storage and electrification of medium-duty special purpose fleets. Additional areas of focus could include charging optimization solutions for fleets and electrification of shared mobility. These potential focus areas are examples to illustrate the purpose of the PRI initiative. The Company has not predetermined specific projects it would pursue, but would plan to solicit input from stakeholders prior to pursuing specific PRI projects. Plus, the PRI provides an opportunity to partner with local public and private sector entities who may be able to bring additional funding and/or expertise to specific projects.

Q. DOES THE COMPANY HAVE SPECIFIC PLANS FOR STAKEHOLDER ENGAGEMENT RELATED TO PRI FOR THE TERM OF THE MULTI-YEAR RATE PLAN?

A. Yes. The Company has in place an EV advisory group that was originally established to provide input on the Fleet and Public Charging pilots through semi-annual meetings with support from a facilitator. These meetings are intended to foster discussion about the Company's pilots and programs, gather ideas for continuing to improve pilots as well as new initiatives, and discuss how the pilots should scale or may be redesigned. As the Company's EV offerings have expanded over the past few years, its intent is to use these semi-annual advisory group meetings to gather feedback and input from stakeholders on all EV programs and pilots in market, ensure transparency and share lessons learned, as well as to assess our customers' experiences and perceptions about EVs that could lead to increased adoption. Additionally, the Company intends to present proposals for specific PRI projects to its EV advisory group prior to implementing any PRI projects, and to take stakeholder feedback into consideration in developing and deploying PRI projects.

Q. WHAT ARE THE BENEFITS OF THE PRI INITIATIVE?

A. Potential benefits of the PRI include the following opportunities:

1) Increased understanding of opportunities for increasing the efficiency of the grid with transportation electrification technologies.
2) More data points on solutions to support providing greater access to the benefits of transportation electrification, including ride sharing and ride hailing applications.
3) Increased awareness for the opportunities for reducing greenhouse gas emissions and improving air quality.

4) Additional support for stimulating innovation in our service territory and helping position Minnesota as a leader on transportation electrification.

Q. WHAT ARE THE OVERALL BUDGETED EXPENDITURES FOR THE PRI INITIATIVE DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. Table 42 below provides the budgeted expenditures for the PRI initiative for 2022, 2023, and 2024. Note that the budgeted capital is included in the Distribution budget, and the capital expenditures shown below are reflected in the overall capital additions shown in Table 42.

Table 42

Partnership, Research, and Innovation Proposed Budget – Expenditures			
	2022	2023	2024
Capital	$1,000,000	$4,000,000	$4,000,000
O&M	$1,000,000	$1,000,000	$1,000,000

Q. HOW DID THE COMPANY BUDGET FOR THE PRI INITIATIVE?

A. Since this budget provides for flexibility to implement projects that will be identified during the MYRP period, specific project costs are not identified. The budgets were established based on the Company's current experience operating EV infrastructure programs and the comparable PRI initiative in our Colorado service territory. As discussed earlier in this section, budgeting in this way is intended to avoid the need for the Company to request deferral of costs associated with this set of new EV initiatives that will take stakeholder input into account and are in the public interest or designed to support public policy goals. Potential capital investments within the PRI initiative may include investments in or rebates for EV service connection, EV supply infrastructure, EV charging equipment, and potential IT development. These capital costs are included in the Distribution capital budget in this case. Potential O&M costs for PRI may include project administration, evaluation, and vendor expenditures. These O&M costs are included in the Customer and Innovation budget.

Q. HOW WILL THE COMPANY KEEP THE COMMISSION INFORMED OF PROJECTS AND EXPENDITURES UNDER THE PRI INITIATIVE?

A. The Company intends to report on PRI initiatives in detail in the annual EV reports.[41] This will include details on the work or projects to be implemented, the goals and objectives of each, the associated costs, and reporting on any stakeholder outreach or partnership with local public and private sector entities.

VI. LED STREET LIGHTS

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

A. In this section of my testimony I will describe the Company's LED street lighting program and discuss the compliance requirements stemming from the Company's 2015 rate case regarding the reporting of costs and cost savings associated with the conversion to LED street lights.

Q. PLEASE DESCRIBE THE LED STREET LIGHTING PROGRAM.

A. In October 2015, the Company filed a Petition for Approval of a Light Emitting Diode (LED) Streetlight Rate.[42] The purpose of the petition was to introduce an LED rate that would enable the Company to work with its large municipal customers to explore the benefits of converting existing street lights to LED.

[41] Filed annually on or before June 1 in Docket No. E002/M-15-111, et. at.
[42] *In the Matter of a Petition of Northern States Power Company for Approval of a Light Emitting Diode (LED) Streetlight Rate*, Docket No. E002/M-15-920, PETITION (October 15, 2015).

The goals of the program included: reducing bills; decreasing maintenance and other street light expenses; increasing efficiency; helping to meet energy usage and greenhouse gas emission reduction goals; and improving lighting quality. Although LED fixtures cost more than the existing high pressure sodium (HPS) fixtures, the increased cost was projected to be largely offset by fuel cost savings, maintenance savings and base rate energy and demand cost allocation associated with LED lights.

The LED conversion was voluntary, allowing customers to opt out if they desired, and was scheduled to be implemented over a five-year period over the Company's normal relamping schedule. The Company completed the LED conversion in May 2019.

Q. WHAT LED STREET LIGHTING COMPLIANCE REQUIREMENTS ARE YOU ADDRESSING?

A. As part of the Stipulation of Settlement (Settlement) in the last rate case,[43] the Company agreed to remove capital costs associated with the LED conversion project from revenue requirements in that case. Instead, those costs were included in a regulatory asset that was permitted to be deferred until the next rate case. Pursuant to the Settlement, the Suburban Rate Authority and the City of Minneapolis agreed not to contest Xcel Energy's recovery of the deferred LED costs in the next rate case, but reserved the right to review and challenge the actual costs and savings associated with the LED project using the standards applicable to a utility's recovery of a regulatory asset, as well as the class cost of service, revenue apportionment, and other aspects of street lighting rates.

[43] *In re The Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-15-826, STIPULATION OF SETTLEMENT at pp. 9-11 (Aug. 16, 2016), and FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at ¶¶ 103-05 (March 1, 2017).

The Settlement directed the Company to "maintain reasonably detailed records of LED costs and cost savings compared to HPS lighting derived from a) relamping of LEDs, b) LED service orders, c) LED effect on base rate energy, and d) demand allocation," and to present this information in the next rate case.[44] I will be addressing a) and b) above, while Mr. Nicholas N. Paluck will be addressing c) and d).

Q. PLEASE DESCRIBE THE COSTS OR COST SAVINGS DERIVED FROM ELIMINATING RELAMPING BY CONVERTING TO LED STREET LIGHTS.

A. Historically, the Company conducted proactive relamping of the HPS street lights on a rolling basis, relamping each light approximately every five years. Due to the conversion to LED technology, which does not require relamping, the Company has saved $600,000 per year in relamping costs since 2015. This equates to approximately $3,600,000 million savings to date and the annual savings will continue into the future.

Q. PLEASE DESCRIBE THE COSTS OR COST SAVINGS ASSOCIATED WITH LED SERVICE ORDERS.

A. LED technology lasts significantly longer and requires less maintenance than the replaced HPS street lights. As cobra head street lights were converted to LED from 2016 to 2019, the cost savings associated with fewer service orders for the LED street lights incrementally increased each year. Since the LED conversion was completed in early May 2019, the Company has experienced an approximately 86 percent reduction in street light outages reported for cobra

[44] *In re The Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-15-826, STIPULATION OF SETTLEMENT at pp. 9-11 (Aug. 16, 2016).

head lights in Minnesota each month. Table 43 provides details on the annual number of street light outages reported from 2015 to 2021 for all Street Light Outages under Rate Code A30 and Table 44 for just cobra head lights under the A30 Rate Code.

Table 43

Street Light Outages – Rate Code A30- Street Lighting System Service

(All fixture Types)

Year	Street Light Outages	Percent Reduction	Notes
2015	10,823		Baseline year
2016	10,360	5%	Conversions began in August 2016
2017	7,520	31%	Actuals
2018	5,357	51%	Actuals
2019	3676	65%	Actuals
2020	4329	60%	Actuals
2021 Projected	4625	58%	Projected

Table 44

Street Light Outages – Rate Code A30- Street Lighting System Service

(Cobra Heads Only)

Year	Street Light Outages	Percent Reduction	Notes
2015	10,029		Baseline year
2016	9227	8%	Actual, Conversions began in August 2016
2017	6528	35%	Actual
2018	4118	59%	Actual
2019	1986	81%	Actual, Conversions completed in May
2020	1437	86%	Actual
2021 Projected	1450	86%	Projected

Q. WHAT COST SAVINGS WILL THE COMPANY ACHIEVE DUE TO THE REDUCTION IN SERVICE ORDERS FOR THE LED LIGHTS?

A. Based on the 66 percent reduction in street light outage service calls, the Company estimates that it will save approximately $700,000 in maintenance costs annually.

VII. MINIMUM SYSTEM STUDY AND ZERO INTERCEPT ANALYSIS

Q. WHAT INFORMATION DO YOU PRESENT IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the data inputs, including sources and assumptions, for the minimum system study and zero intercept analysis. Company witness Mr. Michael A. Peppin provides the study and analysis results in his testimony.

A. Minimum System Study

Q. GENERALLY, HOW DOES THE ENGINEERING ORGANIZATION DETERMINE THE MINIMUM CONDUCTOR, CABLE, TRANSFORMER, AND SECONDARY SERVICE EQUIPMENT BEING INSTALLED ON THE DISTRIBUTION SYSTEM?

A. The minimum-size conductor, cable, transformer, and secondary service equipment used in the Minimum System Study were selected by the Engineering Organization according to its field experience and its evaluation of the smallest practical-sized equipment inventories held in the Company's inventory. The "smallest practical-sized equipment" presently utilized on the Company's distribution system in Minnesota has been developed and refined over a number of decades as our industry has matured and progressed.

Although the equipment analyzed as part of the zero intercept component of the study indicates minimum-size equipment that differs from the minimum-size equipment indicated in Table 45, this does not necessarily represent what is presently utilized on the Company's distribution system in Minnesota. The equipment analyzed for the zero intercept component of the study represents the equipment that currently exists on the Company's distribution system in Minnesota, although much of the equipment has not been installed in several decades. As was described above, the smallest sized equipment presently utilized on the Company's distribution system in Minnesota has been continually developed and refined as the system has matured and progressed.

Q. WHAT IS THE MINIMUM-SIZE EQUIPMENT UTILIZED IN THE MINIMUM SYSTEM STUDY?

A. The Minimum System Study presented by Mr. Peppin utilizes the same minimum-size equipment assumptions as were presented in our last rate case. The only difference is that the new Minimum System Study does not include a minimum-size pole assumption.

For the most recent study, we combined the pole and overhead conductor assumptions because these two components are inextricably linked in installations and are combined on our work orders. The installed costs of the poles are, by nature, included in the installed costs for the overhead conductors, as one would not be installed without the other. Furthermore, the size of the pole installed does not necessarily vary with respect to the load-carrying capacity of the conductor. Rather, the size of the pole is determined by the specific minimum height for clearances, and the strength needed for adequate resiliency to accommodate the weather conditions in the particular geographic area of the installation. As a matter of course, we install the minimum-sized pole that we can for each project based on the clearance and resiliency requirements for that particular geographic area.

Table 45 below provides a summary of the minimum-size equipment utilized in the Minimum System Study.

Table 45

Minimum-Size Equipment from Minimum System Study

Description	Minimum-Size Equipment	FERC Account
OH Conductors – Primary OH Conductors – Secondary	#2 ACSR Bare 1/0 Lashed Aerial Cable	365
UG Cables – Primary UG Cables - Secondary	#1/0 ALUM Stranded #1/0 – 2 – 1/0 600 V	366/367
OH Transformers PAD Transformers	10 kVA 10 kVA	368
OH Secondary Service UG Secondary Service Average Length of Service OH Secondary UG Secondary	#2 Triplex #1/0 – 2 – 1/0 600 V 50 feet 50 feet	369

[1] In the analysis to determine installed costs, the cost of the pole was assumed to be included in the cost of the conductor. Therefore, the pole costs were not individually tracked.

Q. ARE THESE REASONABLE ASSUMPTIONS FOR USE IN THIS CASE?

A. Yes. While there are some differences between the minimum-size equipment currently being installed on the Company's system and the assumptions from Table 45 above, overall, the assumptions reasonably approximate the minimum-size equipment being installed today, or in some cases such as transformers, slightly underestimate the minimum-size equipment.

Q. WHAT FACTORS COULD DRIVE CHANGES TO THE MINIMUM-SIZE EQUIPMENT?

A. Our Engineering Organization monitors equipment performance, changes in the industry, and customer requirements. Each of these factors may result in changes to minimum-size equipment. In addition, as we pursue additional grid modernization improvements or employ new technologies to improve reliability within the distribution system, equipment standard changes may occur.

B. Zero Intercept Analysis

Q. HOW WERE THE SPECIFIC CONDUCTORS, CABLES, TRANSFORMERS AND SECONDARY EQUIPMENT SELECTED TO BE STUDIED IN THE ZERO INTERCEPT ANALYSIS?

A. Unlike the Minimum System Study, the Zero Intercept Analysis is very data-intensive. For this reason, the first step in the Zero Intercept Analysis process was to acquire a set of data for all conductors, cables, transformers and secondary equipment that exist on the Company's distribution system in Minnesota. This was done by querying all of the data available on conductors, cables, transformers and secondary equipment in the Company's Geographic Information System (GIS) database. This data was then split into the following specific Property Units: Overhead (OH) Primary, Underground (UG) Primary, OH Secondary, UG Secondary, OH Transformers and UG Transformers.

These Property Units were then further divided into specific sizes and configurations (i.e. 1/0 AL 3ph under the UG Primary Property Unit). The total length (feet) in the GIS was calculated for each specific configuration of conductors and cables, and the total amount of units in the GIS was calculated for each specific configuration of transformers. Then, the total feet or count for each specific configuration was then divided by the total feet or count for its associated Property Unit to acquire the percent contribution of each specific configuration to the total feet or count of the entire Property Unit on the Company's distribution system in Minnesota (i.e., 1/0 AL 3ph represents 31 percent of all UG Primary feet installed on the Company's distribution system in Minnesota).

The configurations with the highest percent contributions towards the overall feet or unit count of each Property Unit were then selected such that at least 90 percent of the total feet or unit count of the Property Unit was covered by the analysis.

Q. HOW DID YOU DETERMINE THE INSTALLED UNIT COSTS FOR EACH SPECIFIC CONFIGURATION?

A. To acquire the data needed to determine the installed unit costs, data from the GIS was queried on completed Distribution Work Orders. When new equipment such as a cable or a transformer is added to the GIS, or when existing equipment is changed, the equipment is associated with a Work Order number. The Work Order number is an identification number for the specific job that was done to install the equipment. Therefore, when the Work Orders were queried from the GIS, all of the specific equipment installed in those Work Orders was acquired. In the Company's 2015 rate case, Work Orders completed from 2010-2015 were used in the analysis. In the current rate case, the Company supplemented these work orders with ones completed from 2007-2009 (the Company's GIS System was implemented in 2007), and ones completed from 2016-2020.

Then, to determine the costs associated with each Work Order, the Work Orders pulled from GIS were queried in the Company's financial management system. This query was able to pull the total cost for each Work Order, and the breakdown of how much was charged to each cost area (regular labor, overtime labor, equipment, stocked materials, etc.). This then gave a breakdown of historical jobs, what was installed in those jobs, and how much the jobs cost.

Q. WHAT WAS DONE TO REFINE THE DATA USED FOR THE ZERO INTERCEPT ANALYSIS?

A. Using the Work Order and cost data, the Work Orders were then filtered down to those in which only one Property Unit and one specific configuration was installed (i.e., a Work Order that only installs 350 feet of 1/0 AL 3ph would be used for the study, but a Work Order that installs both 350 feet of 1/0 AL 3ph and 200 feet of 750 AL 3ph would be filtered out). This was done to ensure accuracy in calculating the installed unit cost for a single specific configuration because we could not parse out the costs for the two different configurations from the entire cost of a Work Order. Although there could have been ways to approximate installed unit costs based on Work Orders that installed multiple different specific configurations, these approximations would have yielded a less accurate result. Also, while the cost data from the study completed in the last rate case included both new and reconstruction work orders to ensure adequate sample sizes for each configuration, the additional work orders that were added only included new construction work ordered to reduce the variability of the unit costs.

The remaining 16,223 Work Orders were then grouped by the specific configuration that was installed (i.e., a list of all Work Orders in which just 1/0

AL 3ph was installed). This Work Order data was then further refined to eliminate any Work Orders that contained erroneous data (i.e., if no material costs or no labor costs were shown, or if the overtime labor costs were greater than the regular labor costs, etc.). The Company utilized all work orders that were included in the last rate case. For the new work orders that were added in the current case, a similar analysis was undertaken. Additionally, an analysis of the skewness of the data for each configuration was conducted to identify unit cost outliers that should be excluded when calculating the average installed cost for each configuration.

Overall, this process of narrowing down the Work Order dataset eliminated thousands of Work Orders. The identification of the Work Orders that contained erroneous data took considerable time and resources, as each Work Order needed to be analyzed on an individual basis. The ultimate dataset used for the analysis was determined to be an adequate representation of installation costs, containing natural variances in job costs.

Q. HOW WAS THE INSTALLED UNIT COST CALCULATED FROM THE DATA THAT WAS ANALYZED?

A. To calculate the installed unit cost for a specific configuration of a Property Unit, the total cost of all Work Orders associated with that specific configuration was divided by the total feet or units installed. For specific configurations that did not have any reliable Work Order data available, estimations were made using the information from other configurations that did have reliable data available.

Installed unit costs were also acquired for Primary Step-down Transformers. The installed unit costs for Primary Step-down Transformers were used for neither the zero intercept, nor the minimum system components of the study, but were needed to determine the overall plant investment of transformers on the distribution system. Insufficient Work Order data was available to identify unit costs for each step-down transformer in the same way as had been done for other Property Units. Instead, material costs were gathered for each step-down transformer, and the average ratio of material cost to installed unit cost for the corresponding installation type (i.e., 1ph OH, 3ph OH, 1ph UG, 3ph UG) of distribution service transformers were used to estimate the installed unit cost of each step-down transformer. For example, the installed unit cost for a 1ph OH step-down transformer was calculated as its material cost multiplied by the average ratio of installed unit cost to material cost for 1ph OH service transformers. This was done because the scope and cost of labor for these installations are similar, and a significantly greater availability of Work Order data was available for distribution service transformers

Q. FOR THE COST DATA USED IN THE ANALYSIS INCLUDED DATA FROM 2007-2020, WAS ANY ADJUSTMENT MADE TO THE UNIT COST DATA TO ACCOUNT FOR THE DIFFERENT COST VINTAGES OF THE DATA?

A. Yes, the final cost data was normalized to the 2015 vintage year using the Handy Whitman Indices.

Q. HOW DID YOU DETERMINE THE LOAD-CARRYING CAPABILITY FOR EACH COMPONENT STUDIED?

A. With regard to the Zero Intercept Analysis, the load-carrying capability is determined as the unique load-carrying capacity identified for each conductor, cable, transformer, and secondary equipment studied. For transformers, this is measured in kVA. For conductors, cables, and secondary service equipment this is measured in Amps. For three-phase conductors and cables, the load-carrying capacity is defined as three times the ampacity of the single-phase conductor or cable.

Q. HOW WAS THE LOAD-CARRYING CAPABILITY FACTORED INTO THE ANALYSIS?

A. The load-carrying capability was factored into the analysis using the unique load-carrying capacity value for each specific configuration. For transformers, this value was the nameplate kVA value. For conductors, cables and secondary equipment, this value was the ampacity. The values for ampacity of the various conductors, cables and secondary service equipment were acquired from the Company's Distribution design and construction manuals. For three-phase conductors and cables, this ampacity value was calculated as three times the single-phase value listed in the Company's Distribution Design and Construction manuals.

Q. ARE THE ASSUMPTIONS IN THE ZERO INTERCEPT ANALYSIS REASONABLE?

A. Yes. The assumptions and eliminations that were made to the data used for the Zero Intercept Analysis were necessary to ensure accurate results were acquired.

VIII. DISTRIBUTION SYSTEM LOSSES

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

A. In its June 12, 2017 Order from our 2015 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 Class Cost of Service Study.[45] As a result, the Commission directed the Company to report in the 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 losses. I will discuss the methods for measuring distribution line losses, while Company witness Mr. Ian R. Benson will discuss the methods for measuring transmission line losses.

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' total peak is reached. There are five categories or distribution subsystems where specific losses occur. Within these categories there may be load and non-load losses, as summarized in the table below. For example, transformers have both load and no-load losses. Load losses are a function of the transformer winding resistance and the load current through the transformer. Transformers and meters also have no-load losses which are a function of voltage.

[45] *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).

Table 46

Distribution Subsystems and Losses

Category	Load Losses	No-Load Losses
Distribution Primary Transformers	Yes	Yes
Primary Distribution Lines	Yes	No
Distribution Secondary Transformers	Yes	Yes
Service Lines and Drops	Yes	No
Meters	No	Yes

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

A. No, not at this time. To measure actual losses on the distribution system, we would need the ability to collect data from locations throughout the distribution system. Specifically, the Company would need the ability to collect energy data at both individual customer premises and from the transformers at each distribution substation. This would allow the Company to evaluate the amount of energy leaving each substation compared to the amount of energy being delivered to the customer. The difference between these two amounts would be used to determine the losses across the distribution system.

Q. WHAT EQUIPMENT WOULD BE NEEDED TO MEASURE ACTUAL LINE LOSSES ON THE DISTRIBUTION SYSTEM?

A. To obtain data at the customer level, AMI meters along with the FAN communication network would need to be installed throughout the system. As I discussed above, the majority of the distribution system is not equipped with

AMI, or any other equipment with similar data collection and communication capabilities.

To collect substation level data, the Company would need SCADA technology at each distribution substation. As of August 2021, approximately 113 of the Company's 242 distribution substations in Minnesota have SCADA functionality. Another 48 substations only have partial SCADA. Even those distribution substations that currently have SCADA functionality only have it on the low side of the transformer, and similar equipment would need to be installed on the high side of the transformer to collect the data needed to quantify the losses that occur in the substation transformer.

Q. IS THERE OTHER DATA THAT THE COMPANY NEEDS TO DETERMINE ACTUAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. Yes. In addition to the customer and substation level data, the Company would also need to collect secondary data regarding the transformers and service lines and lengths to perform an accurate line loss analysis. This information would need to be collected manually as it is not currently tracked by the Company in the detail needed for a line loss analysis.

Once all of the customer and distribution station level data is available, the Company would need to develop or purchase software that could take the field data, integrate data from the DER on the system, and calculate the line losses.

Q. DOES THE COMPANY HAVE AN ESTIMATE OF HOW LONG IT WOULD TAKE TO HAVE THE NECESSARY COMPONENTS TO DETERMINE ACTUAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. As noted above, AMI meters and FAN will be installed by the end of 2024. We expect that the installation of the necessary SCADA infrastructure will not be completed until after 2024.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Distribution capital additions and O&M budgets presented in this rate case. These capital investments are needed to continue to provide safe and reliable service to our customers while replacing infrastructure that has reached the end of its life, responding to localized areas of demand growth, extending service to new customers, and relocating facilities as needed. To support these capital investments and to maintain our existing assets, our O&M expenditures are reasonable and necessary.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Ms. Bloch has more than 30 years of experience in the utility industry where she has compiled a diverse background. She joined Public Service Company of Colorado in 1991 and served in various engineering roles in the four operating companies at Xcel Energy: Manager of Capacity Planning for Xcel Energy, Manager of Distribution Planning for Public Service, Manager of System Planning and Strategy, and Senior Director Electric Distribution Engineering, in addition to her current role.

Ms. Bloch is currently the Regional Vice President, Distribution Operations, for Northern States Power Minnesota and Northern States Power Wisconsin. She is responsible for the electric and natural gas distribution design and electric construction and operations activities for the Company's service areas in the states of North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

Resume

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Education:

Bachelor of Science Electrical Engineering
South Dakota State University

Employment:

Xcel Energy Services

2015-Present	Vice President, Distribution Operations NSPM/WI
2014-2015	Sr. Director, Electric Distribution Engineering
2012-2014	Manager, System Planning and Strategy
2005-2009	Manager, Distribution Capacity Planning
2002-2005	Sr. Engineer, Distribution Capacity Planning

Public Service Company of Colorado

2009-2012	Manager System Planning
1993-2002	Sr. Engineer, Distribution Reliability Assessment
1991-1993	Distribution Standards Engineer

Distribution Ops - Capital Additions
State of MN Electric Jursidiction
Includes AFUDC

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
AGIS	D.0001723.059	FLISR Advanced Function NSPM	(751,417.97)	(944,701.69)	(945,063.79)
AGIS	D.0001900.016	FAN - AGIS - NSPM - MN			(25,841,584.27)
AGIS	D.0001900.074	FAN - AGIS - NSPM - ND	(783,041.34)	(132,660.59)	(38,513.61)
AGIS	D.0001900.075	FAN - AGIS - NSPM - SD	(783,041.34)	(132,660.59)	(38,513.61)
AGIS	D.0001901.043	AMI-DIST-NSPM-MN Full AMI	(83,889,303.76)	(89,277,976.56)	(47,609,078.99)
AGIS	D.0001901.056	AMI-DIST-NSPM-ND Full AMI	(9,831,842.40)	(7,754,758.92)	
AGIS	D.0001901.057	AMI-DIST-NSPM-SD Full AMI	(9,656,567.04)	(7,924,703.80)	
AGIS	D.0001902.009	FLISR - AGIS - NSPM	(2,640,936.00)	(6,892,212.00)	(6,892,212.00)
AGIS	D.0001902.039	FLISR-Comm-Dist Blanket-NSPM	(78,540.00)	(58,908.00)	(58,908.00)
AGIS	D.0001904.040	IVVO-Comm-Dist Blanket-NSPM		(298,729.88)	(4,276,851.04)
AGIS	D.0001908.001	AGIS-Dist-Capital-Line-Contingency-			(1,671,191.21)
AGIS	D.0001908.038	AGIS-Dist-Capital-Line-AMI-Contin-N		(20,266,886.64)	(44,213,103.07)
AGIS	D.0001908.072	AGIS-Dist-Cap-Com-FAN-Cont-NSPM		(1,000,000.00)	(4,200,000.00)
AGIS	D.0001908.077	AGIS-Dist-Capital-Line-AMI-Contin-N		(2,803,444.70)	
AGIS	D.0001908.078	AGIS-Dist-Capital-Line-AMI-Contin-S		(2,803,444.70)	
Asset Health & Reliability	A.0001471.001	SUB Reinf Daytons Bluff DBL Sub			(17,776,190.23)
Asset Health & Reliability	A.0001471.002	LINE Reinf Daytons Bluff DBL Sub			(2,499,363.22)
Asset Health & Reliability	A.0005508.045	Mpls-Oh Rebuilds	(253.70)	(3.51)	(0.04)
Asset Health & Reliability	A.0005508.121	LINE Convert North Broadway NBY 4kV		(990,961.83)	
Asset Health & Reliability	A.0005508.123	LINE Convert Larimore LAR 4kV		(1,124,715.40)	
Asset Health & Reliability	A.0005509.013	ELR STP Vault Tops	(878,887.73)	(554,999.19)	(711,255.53)
Asset Health & Reliability	A.0005509.014	ELR MPLS Vault Tops	(592,121.39)	(1,148,129.85)	(1,593,032.80)
Asset Health & Reliability	A.0005509.021	Mpls-Ug Conversion/Rebuild	(18.12)	(0.24)	
Asset Health & Reliability	A.0005512.008	MPLS UG Network Vault Blanket	(411,924.02)	(479,754.43)	(480,736.05)
Asset Health & Reliability	A.0005512.012	STP UG Network Vault Blanket	(223,535.06)	(240,133.62)	(240,371.74)
Asset Health & Reliability	A.0005521.001	MN Failed Sub Equip Replacement	(3,461,642.76)	(3,148,429.49)	(3,237,116.51)
Asset Health & Reliability	A.0005521.006	ND Failed Sub Equip Replacement	(386,972.66)	(480,726.99)	(496,752.45)
Asset Health & Reliability	A.0005521.023	T ND Install Direct Metering		(919,858.85)	
Asset Health & Reliability	A.0005521.051	ELR MN Sub Feeder Breakers	(2,718,859.73)	(3,242,985.44)	(3,384,170.40)
Asset Health & Reliability	A.0005521.052	ELR MN Sub Switches	(5,558,310.31)	(7,379,898.75)	(7,721,321.30)
Asset Health & Reliability	A.0005521.091	ELR MN Sub Relays	(1,010,651.10)	(1,338,663.93)	(1,400,878.28)
Asset Health & Reliability	A.0005521.092	ELR MN Sub Regulators	(645,855.29)	(844,660.64)	(896,965.33)
Asset Health & Reliability	A.0005521.093	ELR MN Sub Fences	(283,269.52)	(372,097.10)	(395,515.35)
Asset Health & Reliability	A.0005521.094	ELR MN Sub TRs	(5,841,988.42)	(7,560,738.21)	(7,890,201.39)
Asset Health & Reliability	A.0005521.095	Reserve TR 69/13.8 kV 28 MVA	(513,184.61)		
Asset Health & Reliability	A.0005521.103	ELR MN Sub Retirements	39.75	0.54	
Asset Health & Reliability	A.0005521.106	SD Failed Sub Equip Replacement	(408,070.76)	(481,034.80)	(496,756.94)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Asset Health & Reliability	A.0005521.133	SUB Convert Larimore LAR 4kV		(1,768,876.82)	
Asset Health & Reliability	A.0005521.212	MN Failed Sub TR Replacement	(1,515,716.42)	(1,922,432.80)	(1,985,500.70)
Asset Health & Reliability	A.0005549.020	ELR MN Sub RTUs	(154,515.09)	(193,394.05)	(205,662.57)
Asset Health & Reliability	A.0005550.005	NSPM-Accelerated URD Cable Rep	0.16		
Asset Health & Reliability	A.0005585.001	MINNESOTA MAJOR STORM RECOVERY	(29,111.91)	(7.10)	
Asset Health & Reliability	A.0005586.001	NORTH DAKOTA MAJOR STORM RECOVE	(3,172.79)	(0.77)	
Asset Health & Reliability	A.0005587.001	SOUTH DAKOTA MAJOR STORM RECOVE	(1,588.19)	(0.38)	
Asset Health & Reliability	A.0010019.001	MN - OH Rebuild Blanket	(17,838,129.55)	(18,595,502.04)	(19,054,657.22)
Asset Health & Reliability	A.0010019.002	MN - UG Conversion/Rebuild Blanket	(5,273,796.04)	(5,505,462.21)	(5,641,090.49)
Asset Health & Reliability	A.0010019.003	MN - OH Services Renewal Blanket	(613,587.02)	(689,122.12)	(706,845.54)
Asset Health & Reliability	A.0010019.004	MN - UG Services Renewal Blanket	(4,801,088.94)	(4,976,791.14)	(5,099,935.43)
Asset Health & Reliability	A.0010019.005	MN - OH Street Light Rebuild Blanke	(1,359,782.40)	(1,410,648.22)	(1,445,280.09)
Asset Health & Reliability	A.0010019.006	MN - UG Street Light Rebuild Blanke	(1,373,761.93)	(1,425,196.53)	(1,460,261.71)
Asset Health & Reliability	A.0010019.007	MN - Network Renewal Blanket	11,898.26	164.69	2.28
Asset Health & Reliability	A.0010019.008	MN - Pole Replacement Blanket	(31,280,623.78)	(33,821,130.25)	(34,310,406.35)
Asset Health & Reliability	A.0010019.009	MN - Line Asset Health WCF Blanket	(19,690,040.04)	(20,826,280.48)	(21,425,914.44)
Asset Health & Reliability	A.0010019.020	MN Low Cost Reclosers (Single Ph)			(357,628.19)
Asset Health & Reliability	A.0010019.021	MN Pole Top Reinforcements			(4,291,538.26)
Asset Health & Reliability	A.0010019.022	MN High Customer Count Taps			(715,256.38)
Asset Health & Reliability	A.0010019.023	MN Pole Fire Mitigation			(715,256.38)
Asset Health & Reliability	A.0010019.024	MN Porcelain Cutouts	(1,430,512.75)	(3,205,675.41)	(4,270,352.06)
Asset Health & Reliability	A.0010019.025	MN Cable Isolation Activities	(221,989.19)	(201,279.46)	(208,019.41)
Asset Health & Reliability	A.0010020.001	ND - OH Rebuild Blanket	(431,460.05)	(390,527.47)	(398,737.71)
Asset Health & Reliability	A.0010020.002	ND - UG Conversion/Rebuild Blanket	(458,827.18)	(578,041.05)	(593,743.07)
Asset Health & Reliability	A.0010020.003	ND - OH Services Renewal Blanket	(37,151.81)	(36,335.07)	(37,199.48)
Asset Health & Reliability	A.0010020.004	ND - UG Services Renewal Blanket	(142,162.71)	(155,856.57)	(159,793.51)
Asset Health & Reliability	A.0010020.005	ND - OH Street Light Rebuild Blanke	(60,267.82)	(65,457.39)	(67,284.40)
Asset Health & Reliability	A.0010020.006	ND - UG Street Light Rebuild Blanke	(3,053.91)	(3,789.67)	(3,799.85)
Asset Health & Reliability	A.0010020.007	ND - Pole Replacement Blanket	(768,561.26)	(654,980.92)	(435,331.52)
Asset Health & Reliability	A.0010021.001	SD - OH Rebuild Blanket	(890,440.66)	(998,842.55)	(1,024,752.96)
Asset Health & Reliability	A.0010021.002	SD - UG Conversion/Rebuild Blanket	(196,645.16)	(193,910.75)	(198,556.35)
Asset Health & Reliability	A.0010021.003	SD - OH Services Renewal Blanket	(54,373.67)	(57,478.46)	(59,274.02)
Asset Health & Reliability	A.0010021.004	SD - UG Services Renewal Blanket	(83,780.12)	(92,624.25)	(94,620.36)
Asset Health & Reliability	A.0010021.005	SD - OH Street Light Rebuild Blanke	(50,658.95)	(53,199.95)	(54,110.82)
Asset Health & Reliability	A.0010021.006	SD - UG Street Light Rebuild Blanke	(38,436.06)	(38,770.89)	(39,711.59)
Asset Health & Reliability	A.0010021.007	SD - Pole Replacement Blanket	(5,218,903.23)	(3,427,060.47)	(3,236,567.11)
Asset Health & Reliability	A.0010027.001	MN - URD Cable Replacement Blanket	(27,844,672.03)	(28,177,158.03)	(29,022,785.57)
Asset Health & Reliability	A.0010027.002	MN - Feeder Cable Replacement	(4,655,702.06)	(5,916,523.77)	(6,171,463.70)
Asset Health & Reliability	A.0010027.003	MN - REMS Blanket	(486,114.62)	(502,356.39)	(517,886.92)
Asset Health & Reliability	A.0010027.004	MN - FPIP Blanket	(2,040,774.02)	(2,009,973.40)	(2,069,914.46)
Asset Health & Reliability	A.0010028.001	ND - URD Cable Replacement Blanket	(983,213.23)	(1,006,318.46)	(1,036,587.18)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Asset Health & Reliability	A.0010028.003	ND - REMS Blanket	(43,441.84)	(50,619.09)	(52,611.75)
Asset Health & Reliability	A.0010028.004	ND - FPIP Blanket	(165,046.52)	(200,771.87)	(207,649.57)
Asset Health & Reliability	A.0010029.001	SD - URD Cable Replacement Blanket	(1,852,914.75)	(2,012,549.95)	(2,073,181.80)
Asset Health & Reliability	A.0010029.002	SD - Feeder Cable Replacement Blank	(221.42)	(0.05)	
Asset Health & Reliability	A.0010029.003	SD - REMS Blanket	(129,254.77)	(151,025.23)	(156,021.19)
Asset Health & Reliability	A.0010029.004	SD - FPIP Blanket	(225,538.15)	(251,490.92)	(259,430.97)
Asset Health & Reliability	A.0010069.004	MN LED Post Top Conversion	(767,448.73)	(970,377.53)	(1,002,056.71)
Asset Health & Reliability	A.0010077.007	YLM211 and YLM212 Rebuild OH lines		(3,099.84)	
Asset Health & Reliability	A.0010077.012	Rebuild Clara City CLC221			(1,962,638.00)
Asset Health & Reliability	A.0010077.022	T Rebuild West St Cloud to Millwood		(5,502,250.17)	
Asset Health & Reliability	A.0010077.024	Rebuild Sacred Heart SCH211	(1,021,587.30)		
Asset Health & Reliability	A.0010077.025	ELR STP Network TR	(94,824.39)	(160,376.66)	(550,079.72)
Asset Health & Reliability	A.0010077.026	ELR MPLS Network TR	(394,767.79)	(765,421.35)	(1,062,021.99)
Asset Health & Reliability	A.0010077.032	Rebuild Downtown St. Paul Manholes		(7,528,336.45)	
Asset Health & Reliability	A.0010077.038	MN Arrestor Replacement Program	(577,534.89)	(718,544.45)	(953,535.72)
Asset Health & Reliability	A.0010077.039	SE Region Reliability Initiative	(2,189,811.69)	(2,741,732.14)	(2,859,079.75)
Asset Health & Reliability	A.0010077.044	T Underbuild Brooten to Paynesville	(587,587.85)		
Asset Health & Reliability	A.0010077.048	LINE ELR Install Gaiter Lake Sub			(1,216,786.71)
Asset Health & Reliability	A.0010077.049	MN ELR Reclosers			(1,441,937.28)
Asset Health & Reliability	A.0010079.003	Rebuild Cherry Creek CHC321	(229,645.38)		
Asset Health & Reliability	A.0010085.004	MN Install Viper Reclosers CSG	(15,309,336.75)		
Asset Health & Reliability	A.0010093.030	LINE Convert Butterfield BTF 4kV		(899,873.26)	
Asset Health & Reliability	A.0010117.004	LAND ELR Install Gaiter Lake Sub	(150,000.00)		
Asset Health & Reliability	A.0010125.002	ELR MN Sub Batteries	(399,763.84)	(346,664.63)	(366,566.38)
Asset Health & Reliability	A.0010125.014	ELR MPLS Network Protectors	(638,268.80)	(783,107.50)	(1,063,303.80)
Asset Health & Reliability	A.0010125.015	ELR STP Network Protectors	(226,800.50)	(169,961.38)	(222,015.01)
Asset Health & Reliability	A.0010125.029	T Replace Coon Creek CNC Relays	(217,400.53)		
Asset Health & Reliability	A.0010125.030	ELR Mobile Substation Renewal	(2,499,265.93)	(1,923,094.04)	(1,980,502.86)
Asset Health & Reliability	A.0010125.032	Reserve TR 69/4.16 kV 7 MVA	(237,549.85)		
Asset Health & Reliability	A.0010125.033	Reserve TR 115/13.8 kV 50 MVA	(860,770.88)		
Asset Health & Reliability	A.0010125.034	SUB ELR Install Gaiter Lake Sub			(2,413,437.08)
Asset Health & Reliability	A.0010126.003	RETIRE Convert North Broadway NBY 4			(142,469.35)
Asset Health & Reliability	A.0010126.004	ELR ND Sub VARIOUS	(1,274,219.56)	(1,525,325.24)	(1,595,952.01)
Asset Health & Reliability	A.0010127.003	ELR SD Sub VARIOUS	(1,788,095.68)	(2,286,955.72)	(2,392,995.41)
Asset Health & Reliability	A.0010133.020	SUB Convert Butterfield BTF 4kV		(1,628,429.22)	
Asset Health & Reliability	A.0010133.078	Reserve TR 115/13.8 kV 50 MVA		(946,295.07)	
Asset Health & Reliability	A.0010134.002	Reserve TR 115/23.9 kV 50 MVA	(860,770.88)		
Capacity	A.0000718.003	LINE Reinforce Stockyards STY Feede		(2,663,154.03)	
Capacity	A.0000718.004	SUB Reinforce Stockyards STY Feeder		(151,851.06)	
Capacity	A.0005502.016	LINE Extend Crooked Lake CRL033			(1,153,851.99)
Capacity	A.0005502.024	LINE Install Wyoming WYO Feeder			(2,013,210.79)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Capacity	A.0005502.208	LINE Install Birch Area Sub			(2,873,720.80)
Capacity	A.0005503.021	Install Baytown BYT Feeders			(4,375,727.20)
Capacity	A.0005517.023	Substation Land - MN	(3,137.39)	(43.43)	(0.60)
Capacity	A.0005517.040	LAND Install Birch Area Sub		(700,000.00)	
Capacity	A.0005522.001	MN - Sub Capacity WCF Blanket	(1,709,989.98)	(2,445,710.92)	(2,675,476.24)
Capacity	A.0005522.005	Minnesota-Sub Capac Reinforcem	(7,609.16)	(6.10)	
Capacity	A.0005522.277	SUB Install Wyoming WYO Feeder			(506,467.84)
Capacity	A.0005522.339	SUB Install La Crescent LAC TR2		(1,935,619.53)	
Capacity	A.0005522.354	SUB Install Birch Area Sub			(4,050,309.66)
Capacity	A.0010003.007	MN - New Business Network Blanket	(350,226.28)	(361,122.15)	(369,801.98)
Capacity	A.0010035.001	MN - OH Reinforcement Blanket	(1,031,740.89)	(1,177,140.50)	(1,208,470.26)
Capacity	A.0010035.002	MN - UG Reinforcement Blanket	(1,549,238.59)	(1,804,819.70)	(1,852,289.83)
Capacity	A.0010035.003	MN - Network Reinforcement Blanket	(9,264.34)	(128.23)	(1.78)
Capacity	A.0010035.004	MN - Line Capacity WCF Blanket	(1,709,989.98)	(2,445,710.92)	(3,864,261.28)
Capacity	A.0010036.001	ND - OH Reinforcement Blanket	(78,435.56)	(82,321.20)	(84,225.97)
Capacity	A.0010036.002	ND - UG Reinforcement Blanket	(50,254.98)	(56,162.19)	(57,225.22)
Capacity	A.0010037.001	SD - OH Reinforcement Blanket	(65,518.92)	(68,237.58)	(70,126.20)
Capacity	A.0010037.002	SD - UG Reinforcement Blanket	(37,586.85)	(42,321.67)	(43,362.49)
Capacity	A.0010061.008	MN - New Business Network Vault	(4,471.00)	(65.20)	(0.93)
Capacity	A.0010077.037	Install Lake Yankton LAY061 Neutral	(345,035.60)		
Capacity	A.0010093.010	Extend Main Street MST074	(614,116.45)		
Capacity	A.0010093.017	Install Feeder Tie EBL064		(150,147.39)	
Capacity	A.0010093.025	LINE Install Cannon Falls Trans CTF			(120,189.22)
Capacity	A.0010093.028	LINE Reinforce Kasson KAN TR1	(575,341.13)		
Capacity	A.0010093.035	Reinforce Brooklyn Park BRP062		(200,196.53)	
Capacity	A.0010093.037	Reinforce Twin Lakes TWL081		(2,032,515.15)	
Capacity	A.0010093.055	LINE Install La Crescent LAC TR2		(287,721.23)	
Capacity	A.0010093.056	LINE Install Elm Creek ECK 34.5kV T	(4,421,950.63)		
Capacity	A.0010093.070	LINE Reinforce Veseli VES TR1			(336,529.77)
Capacity	A.0010093.077	Extend Saint Louis Park SLP092			(1,063,168.61)
Capacity	A.0010093.078	LINE Install Midtown MDT Feeder	(2,233,108.97)		
Capacity	A.0010093.079	Install Feeder Tie SOU083 to MDT074	(100,772.07)		
Capacity	A.0010093.084	LINE Reinforce Hyland Lake HYL TRs		(1,585,824.75)	
Capacity	A.0010093.087	LINE Install Hiawatha West HWW Feed	(40,460.10)		
Capacity	A.0010093.104	Install Feeder Tie ALD081-ALD098			(359,929.28)
Capacity	A.0010093.105	LINE Reinforce Faribault FAB TR1			(451,523.16)
Capacity	A.0010093.108	Extend Woodbury WDY321 for WDY312	(555,477.31)		
Capacity	A.0010093.110	Reinforce Shepard SHP062 and SHP071		(646,454.46)	
Capacity	A.0010093.112	Reinforce Belgrade feeder BEG001	(47,510.06)		
Capacity	A.0010093.113	LINE Reinforce TSS TR01			(1,762,927.70)
Capacity	A.0010093.117	MN Grid Reinforcements	(1,595,814.57)	(3,491,492.82)	(6,985,164.94)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Capacity	A.0010093.119	C Reinforce Parkers Lake PKL071	(203,751.77)		
Capacity	A.0010093.121	Transfer BLH062 to RSP061	(71,265.10)		
Capacity	A.0010093.122	Load Transfer OSS061-OSS075	(28,506.02)		
Capacity	A.0010093.123	Extend Southtown Feeder SOU087	(62,427.05)		
Capacity	A.0010093.124	Install Feeder Tie SDX312-FSL311	(725,022.07)		
Capacity	A.0010093.126	Reinforce Osseo OSS064		(181,815.30)	
Capacity	A.0010093.127	Extend Main Street Feeder MST066			(707,259.05)
Capacity	A.0010093.131	LINE Install Southridge SRD212 Fdr		(738,484.44)	
Capacity	A.0010093.133	LINE Reinforce Pine Bend PBE TR01		(1,246,791.90)	
Capacity	A.0010094.004	Install GAT022 Fdr Tie Switches		(167,569.59)	
Capacity	A.0010095.015	Install West Sioux Falls WSF073 Fee			(350,398.14)
Capacity	A.0010095.021	LINE Install South Renner SRN TR02			(570,345.07)
Capacity	A.0010101.001	SUB MN Feeder Load Monitoring	(5,968,154.45)	(6,607,803.12)	(6,809,539.05)
Capacity	A.0010133.013	Reinforce Pine Island TR1			(1,908,233.98)
Capacity	A.0010133.016	SUB Reinforce Kasson KAN TR1	(2,840,063.24)		
Capacity	A.0010133.023	SUB Reinforce Sibley Park SIP Sub E			(100,113.75)
Capacity	A.0010133.044	Install Midtown MDT TR2	(4,654,422.35)		
Capacity	A.0010133.046	SUB Install Cannon Falls Trans CTF			(1,902,960.74)
Capacity	A.0010133.053	Reinforce Tanners Lake TLK Sub Equi			(200,227.51)
Capacity	A.0010133.055	SUB Extend Crooked Lake CRL033			(50,518.51)
Capacity	A.0010133.065	SUB Reinforce Veseli VES TR1			(2,438,810.49)
Capacity	A.0010133.070	SUB Install Midtown MDT Feeder	(504,953.67)		
Capacity	A.0010133.072	SUB Install Hiawatha West HWW Feede	(500,876.67)		
Capacity	A.0010133.073	SUB Reinforce Hyland Lake HYL TRs		(5,861,350.29)	
Capacity	A.0010133.079	SUB Reinforce Faribault FAB TR1			(1,557,835.82)
Capacity	A.0010133.082	SUB Reinforce Feeders RAM073 RAM061		(261,704.02)	
Capacity	A.0010133.083	SUB Reinforce TSS TR01			(1,256,017.89)
Capacity	A.0010133.089	Reinforce Glenwood GLD Sub Equip		(710,702.99)	
Capacity	A.0010133.093	Reinforce Parkers Lake PKL Sub	(701,227.34)		
Capacity	A.0010133.094	SUB Install Southridge SRD212 Fdr		(609,229.52)	
Capacity	A.0010133.096	SUB Reinforce Pine Bend PBE TR01		(3,238,629.31)	
Capacity	A.0010134.003	SUB ND Feeder Load Monitoring	(457,463.90)	(538,354.71)	(555,608.32)
Capacity	A.0010135.013	SUB Install South Renner SRN TR02			(2,659,087.17)
Capacity	A.0010135.014	SUB SD Feeder Load Monitoring	(522,811.04)	(615,007.95)	(634,325.55)
Capacity	A.0010147.002	LINE Install Louise LOU TR2		(2,874,302.74)	
Capacity	A.0010147.003	SUB Install Louise LOU TR2		(5,718,189.68)	
Capacity	A.0010174.001	SUB Install Great Plains Area Sub		(6,036,349.35)	
Capacity	A.0010174.002	LINE Install Great Plains Area Sub		(7,640,991.91)	
Electric Vehicles	A.0010180.001	MN Electric Vehicle Program	(68,697,944.10)	(55,487,682.51)	(43,200,630.99)
Electric Vehicles	A.0010180.005	MN Electric Vehicle Program FLEET	(29,200.77)	(425.90)	(6.19)
Electric Vehicles	A.0010180.013	MN EV Public - Line Extension	(1,258,390.21)	(2,049,369.70)	(2,536,428.06)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Electric Vehicles	A.0010180.016	MN EV Fleet - Line Extension	(887,225.29)	(939,170.58)	(1,032,918.31)
Electric Vehicles	A.0010180.018	MN EV Public - Infrastructure Blank	(4,413,101.41)	(7,129,101.15)	(8,821,430.02)
Electric Vehicles	A.0010180.019	MN EV Fleet - Charging Equipment Bl	(296,417.82)	(265,985.66)	(292,446.89)
Electric Vehicles	A.0010180.020	MN EV Fleet - Infrastructure Blanke	(2,657,977.28)	(2,714,752.72)	(2,983,155.88)
Electric Vehicles	A.0010180.025	MN EV Residential - Charging Equip	(831,444.67)	(1,136,473.47)	(1,617,714.84)
Fleet, Tools and Communications	A.0005516.030	Scrap Sale Credits-MN	(146.13)		
Fleet, Tools and Communications	A.0005549.043	ND Communications Equipment	(47.17)	(0.03)	
Fleet, Tools and Communications	A.0005553.001	COMM MN Fiber Buildout	(4,247,324.46)	(5,315,318.90)	(5,508,072.41)
Fleet, Tools and Communications	A.0005585.003	NSM - MN CAPITALIZED ELECTRIC LOCA	(778,286.05)	(405,235.97)	(400,072.47)
Fleet, Tools and Communications	A.0005586.003	NSM - ND CAPITALIZED ELECTRIC LOCA	(175,029.23)	(145,671.80)	(145,995.46)
Fleet, Tools and Communications	A.0005587.003	NSM - SD CAPITALIZED ELECTRIC LOCAT	(46,020.31)	(32,997.72)	(32,999.96)
Fleet, Tools and Communications	A.0006059.002	MN-Dist Electric Tools and Equip	(1,593,617.61)	(1,339,265.48)	(1,374,366.08)
Fleet, Tools and Communications	A.0006059.003	ND-Dist Electric Tools and Equip	(93,485.45)	(84,893.61)	(87,525.40)
Fleet, Tools and Communications	A.0006059.004	SD-Dist Dist Tools and Equip	(149,574.55)	(123,385.83)	(126,135.73)
Fleet, Tools and Communications	A.0006059.014	MN-Dist Subs Tools and Equip	(419,395.40)	(342,771.35)	(352,274.64)
Fleet, Tools and Communications	A.0006059.020	MN-DistLogistics	(327,787.18)	(236,979.10)	(243,428.99)
Fleet, Tools and Communications	A.0006059.021	SD-Dist Logistics	(3,451.55)	(47.79)	(0.65)
Fleet, Tools and Communications	A.0006059.024	MN-Dist Tools Common	(160,692.76)	(116,481.68)	(119,516.01)
Fleet, Tools and Communications	A.0006059.473	Logistics - NSPM - Tools - ND	(12,425.60)	(171.99)	(2.38)
Fleet, Tools and Communications	A.0006059.474	Nspm Metering Sys-Tools & Equi	(237,250.60)	(211,128.28)	(216,623.33)
Fleet, Tools and Communications	A.0006059.477	Logistics - Fencing - NSPM	(7,593.43)	(105.09)	(1.46)
Fleet, Tools and Communications	A.0006059.478	Logistics - Security Equipment	(26,231.82)	(363.09)	(5.02)
Fleet, Tools and Communications	A.0006059.479	Logistics Security Eqiupment N	(7,593.43)	(105.09)	(1.46)
Fleet, Tools and Communications	A.0006059.511	Tools and Equipment WCF	(338,578.02)	(484,250.76)	(155,683.30)
Fleet, Tools and Communications	A.0010045.001	MN - Communication Equipment Blanke	(41,145.34)	(569.50)	(7.89)
Fleet, Tools and Communications	A.0010046.001	ND - Communication Equipment Blanke	(12,728.28)	(176.18)	(2.44)
Fleet, Tools and Communications	A.0010047.001	SD - Communication Equipment Blanke	(13,978.16)	(193.47)	(2.69)
Fleet, Tools and Communications	A.0010101.002	COMM MN Feeder Load Monitoring	(1,905,074.20)	(2,202,377.68)	(2,270,453.26)
Fleet, Tools and Communications	A.0010101.012	Install Network Monitoring St. Paul	(870,412.29)	(1,000,290.96)	(1,009,572.22)
Fleet, Tools and Communications	A.0010101.013	Install Network Monitoring Mpls	(1,028,473.94)	(1,480,305.52)	(1,512,899.25)
Fleet, Tools and Communications	A.0010101.014	NSPM Cybersecurity Measures	(1,837,448.03)	(2,351,921.59)	(2,598,396.43)
Fleet, Tools and Communications	A.0010102.001	ND Feeder Load Monitoring DCP - COM	(147,462.67)	(179,830.44)	(185,986.23)
Fleet, Tools and Communications	A.0010103.001	COMM SD Feeder Load Monitoring	(152,490.76)	(180,035.54)	(186,163.81)
Fleet, Tools and Communications	A.0010174.007	COMM - Install Great Plains Sub		(60,058.96)	
Mandates	A.0001471.004	Relocate Daytons Bluff DBL061	(4,240,133.12)		
Mandates	A.0010011.001	MN - OH Relocation Blanket	(6,606,440.91)	(6,858,006.14)	(7,027,447.30)
Mandates	A.0010011.002	MN - UG Relocation Blanket	(5,670,112.69)	(5,796,501.58)	(5,939,541.51)
Mandates	A.0010011.003	MN - UG Service Conversion Blanket	(1,477,746.98)	(1,416,954.82)	(1,452,274.62)
Mandates	A.0010011.004	MN - Mandate WCF Blanket	(3,419,979.97)	(6,943,409.81)	(10,663,375.66)
Mandates	A.0010012.001	ND - OH Relocation Blanket	(157,026.99)	(144,720.68)	(148,025.57)
Mandates	A.0010012.002	ND - UG Relocation Blanket	(102,510.19)	(85,388.69)	(87,025.41)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Mandates	A.0010012.003	ND - UG Service Conversion Blanket	(44,789.72)	(43,526.00)	(44,406.91)
Mandates	A.0010013.001	SD - OH Relocation Blanket	(728,038.91)	(828,209.31)	(849,554.49)
Mandates	A.0010013.002	SD - UG Relocation Blanket	(233,373.54)	(247,644.85)	(253,463.48)
Mandates	A.0010013.003	SD - UG Service Conversion Blanket	(53,980.31)	(63,232.70)	(65,159.51)
Mandates	A.0010019.010	MN - Pole Transfer (3rd Party) Blan	(548,974.10)	(631,176.83)	(650,763.01)
Mandates	A.0010069.003	MPLS Mandates WCF	(5,263,570.34)	(7,575,974.31)	(7,742,784.04)
Mandates	A.0010069.035	Relocate Lone Oak LOK062 Feeder	(772,177.35)		
Mandates	A.0010070.001	Relocation Minot Flood Protection	(556,135.01)		
New Business	A.0005500.026	Mpls-Oh Extension	(6.86)	(0.09)	
New Business	A.0005500.034	Southeast-Oh Extension	(8.40)	(0.11)	
New Business	A.0005501.012	Mpls-New Ug Extension	(43,298.20)	(711.53)	(11.40)
New Business	A.0005501.014	Edina-Ug Extensions	(1.53)	(0.01)	
New Business	A.0005501.016	Northwest - Ug Extensions	(2,472.52)	(36.07)	(0.51)
New Business	A.0006062.001	Distribution CIAC MN Elec	1,575,498.88	1,724,154.37	1,778,331.02
New Business	A.0006062.003	Distribution CIAC SD Elec	253,462.50	257,163.46	265,160.17
New Business	A.0006062.004	Distribution CIAC ND Elec	196,832.60	205,368.18	212,265.24
New Business	A.0010003.001	MN - OH Extension Blanket	(1,780,446.03)	(1,797,463.73)	(1,846,855.76)
New Business	A.0010003.002	MN - UG Extension Blanket	(19,872,544.48)	(20,109,009.09)	(20,665,943.91)
New Business	A.0010003.003	MN - OH New Services Blanket	(1,193,858.31)	(1,139,498.49)	(1,170,745.48)
New Business	A.0010003.004	MN - UG New Services Blanket	(10,989,112.36)	(10,996,229.97)	(11,300,294.93)
New Business	A.0010003.005	MN - OH New Street Light Blanket	(337,167.33)	(334,556.15)	(342,409.29)
New Business	A.0010003.006	MN - UG New Street Light Blanket	(460,813.27)	(268,587.62)	(272,647.59)
New Business	A.0010003.008	MN - New Business WCF Blanket	(2,735,983.98)	(3,913,137.47)	(3,994,030.85)
New Business	A.0010004.001	ND - OH Extension Blanket	(23,815.60)	(16,108.17)	(16,805.16)
New Business	A.0010004.002	ND - UG Extension Blanket	(795,146.28)	(886,900.58)	(913,007.05)
New Business	A.0010004.003	ND - OH New Services Blanket	(185,988.74)	(64,337.31)	(63,822.17)
New Business	A.0010004.004	ND - UG New Services Blanket	(428,635.39)	(457,193.38)	(470,408.72)
New Business	A.0010004.005	ND - OH New Street Light Blanket	(23,594.32)	(28,742.68)	(29,800.10)
New Business	A.0010005.001	SD - OH Extension Blanket	(258,414.13)	(192,992.92)	(197,821.85)
New Business	A.0010005.002	SD - UG Extension Blanket	(3,335,952.82)	(3,454,279.68)	(3,550,026.47)
New Business	A.0010005.003	SD - OH New Services Blanket	(33,037.16)	(38,734.96)	(39,800.00)
New Business	A.0010005.004	SD - UG New Services Blanket	(884,868.24)	(754,754.87)	(773,845.76)
New Business	A.0010005.005	SD - OH New Street Light Blanket	(31,389.48)	(27,864.41)	(28,801.78)
New Business	A.0010005.006	SD - UG New Street Light Blanket	(159,410.20)	(146,441.77)	(150,206.91)
New Business	A.0010061.012	Extend Waseca WAS231	(912,710.79)		
New Business	D.0005014.004	MN Elec Distribution Transformers	(19,287,226.44)	(20,537,534.05)	(20,881,299.83)
New Business	D.0005014.005	ND Electric Distribution Transforme	(1,338,048.73)	(1,400,300.40)	(1,423,724.64)
New Business	D.0005014.006	SD Electric Distribution Transforme	(1,338,048.73)	(1,400,300.40)	(1,423,724.64)
New Business	D.0005014.021	MN-Electric Meter Blanket	(4,506,088.04)	(3,894,072.01)	(2,769,254.71)
New Business	D.0005014.022	ND-Electric Meter Blanket	(283,313.65)	(265,842.97)	(188,960.11)
New Business	D.0005014.023	SD-Electric Meter Blanket	(283,313.65)	(265,842.97)	(188,960.11)

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023	State of MN Electric Jurisdiction 2024
Solar	A.0005566.013	Extend facilities to serve NW	494.26	33.95	2.33
Solar	A.0005566.014	Aurora Solar Sub Reinforcement	381.38	107.71	30.42
Solar	A.0005566.017	NW Solar Garden Extensions	(10,304.42)	(748.48)	(54.25)
Solar	A.0005566.018	NPT Solar Garden Extensions	45,170.34	3,104.08	213.32
Solar	A.0005566.020	Solar Gardens Communications - CSG	181,016.41	12,439.36	854.82
Solar	A.0005566.021	MN-Solar Garden Sub Comm	(1.74)		
Solar	A.0005566.022	MN-Solar Garden Sub Work	(2,430.81)	(0.61)	
Solar	A.0005566.023	WBL Solar Garden Extensions	(46,563.50)	(3,382.20)	(245.12)
Solar	A.0005566.024	MG Solar Garden Ext	10,034.24	689.55	47.38
Solar	A.0005566.025	NW Solar Garden Extensions	20,894.81	1,435.88	98.67
Solar	A.0005566.026	Solar Garden Ext - Shorewood	5,560.30	1.35	

Distribution's O&M Costs by Category: 2018-2024
NSPM-Electric
(Dollars in Millions)

NSPM Electric	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Internal Labor	50.6	47.7	43.0	43.9	46.5	49.0	50.5
Contract Labor	9.4	14.5	9.2	10.5	10.9	11.5	11.5
Vegetation Management	32.4	35.4	23.8	41.2	43.4	46.0	46.2
Damage Prevention Locates	8.1	7.7	11.0	13.1	14.9	14.4	14.6
AGIS	0.9	1.1	1.6	5.2	6.0	4.7	4.0
Other (Fleet, Materials, Employee Expenses, Etc.	15.3	10.5	7.8	7.1	6.0	6.0	6.0
Total*	**116.7**	**116.8**	**96.5**	**121.0**	**127.7**	**131.6**	**132.9**

**Includes Distribution's portion of the O&M associated with the Company's AGIS deployment a portion of which will be recovered through the TCR Rider.*

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

The FLISR CBA model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated and contractual pricing.

Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minnesota Rule 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material**: The Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics and Regulatory and Distribution
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the fourth quarter of 2021.