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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-19-564
Exhibit___(KAB-1)

Distribution

November 1, 2019

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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 28 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 also support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative, which is a portfolio of grid modernization investments to improve reliability, shorten the duration of power outages, integrate renewables, and empower customers with more information to control and track their energy use. 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.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

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.

Traditionally, much of Distribution's investments and efforts have been focused on maintaining the reliability, resiliency, and health of our existing distribution facilities. We regularly evaluate the health of the key components of our distribution system and make the necessary investments to ensure these facilities are safe and reliable. This includes replacing aging poles, wires, underground cables, and substation transformers. Throughout the term of this multi-year rate plan, we are continuing and increasing our investments in these established asset health and reliability programs.

At the same time, we are placing greater focus on the portion of our system that is closest to our customers, including tap lines and the secondary system. To better address the needs of this portion of our system we will launch the Incremental System Investment (ISI) Initiative in 2021. The ISI Initiative will expand some of our existing programs, such as our cable replacement program, as well as adding new programs, such as a targeted undergrounding program. This initiative would provide several benefits to customers including making our system more resilient and reliable, reducing O&M, and enabling increased adoption of distributed energy resources (DER). It will also improve safety for both our workers and our customers.

While our traditional areas of investment are important to maintaining the reliability and condition of the basic elements of our system, the electric industry is also undergoing a fundamental change. As aging distribution infrastructure approaches the end of its useful life, emerging technologies promise enhanced functionalities and operational efficiencies. Technological and manufacturing advances have also driven down the costs of solar panels and electric vehicles placing them within the reach of the average customer. The pervasive nature of electronics in our society and the unlimited access to data that they provide has further elicited changes in customer expectations.

Our current investment in our distribution facilities has not kept pace with these technological advances or our customers' demands. Our current distribution system was designed to facilitate a basic one-way flow of both electricity and information, with limited monitoring points beyond the substation. As a result, we have limited insight into our customers' energy experience. This limits our ability to timely respond to outages as in many outage situations we rely on customers calling to let us know their power is out. We are also unable to provide timely energy use information to customers or to detect voltage issues absent a customer complaint. The majority of our current distribution system lacks intelligent and automated devices that would facilitate a quicker response to outages on the system. Our electric system is also not equipped to accommodate the amount of distributed generation and electric vehicle charging that is anticipated in the coming years.

We have begun to address these limitations and transition to an advanced grid by taking a strategic building block approach. We have focused first on foundational elements that are needed to support fundamental applications. For example, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide visibility and control necessary for enhanced distribution planning and DER integration. We are also in the process of implementing a residential Time of Use (TOU) pilot (TOU pilot), as well as installing Advanced Metering Infrastructure (AMI) meters and two-way communication via a Field Area Network (FAN) in a limited area of the Twin Cities metro.

Now is the time to take the next major step towards an advanced grid. During the term of the multi-year rate plan, we propose to implement further elements of the Company's AGIS initiative including a full AMI and FAN implementation across our service territory, a targeted installation of Integrated Volt VAr Optimization (IVVO) for voltage monitoring and control, and Fault Location, Isolation, and Service Restoration (FLISR), for improved reliability.

It is an opportune time to make these investments as our current Automated Meter Reading (AMR) meters that have served our customers since the 1990s are at the end of their service contract and will no longer be supported by the vendor past the mid-2020s. In addition, AMI technology has advanced to the point where the technology has been well-tested by other utilities, and its two-way communication and command capabilities will provide multiple benefits for our customers and our operation of the grid.

With this background, my Direct Testimony starts by describing 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 $235.3 million for 2020, $350.0 million for 2021, and $463.1 million for 2022 on a State of Minnesota Electric Jurisdiction basis. These capital additions are spread across investments in our traditional budget groupings of Asset Health and Reliability, New Business, Capacity, Mandates, and Tools and Equipment. I provide information about the key capital projects in each of these categories over the term of the multi-year rate plan.

I also discuss the Distribution O&M budgets for 2020 to 2022, which are driven by internal and contract labor costs, fleet, and materials. I also explain why our O&M budgets are reasonable and reflects expenditures that are needed to ensure that our distribution system is safe and reliable.

Next, I discuss Distribution's key role in implementing the AGIS initiative that includes installing the new AMI meters, FAN devices, FLISR devices, and IVVO devices that are necessary to achieving the goals of a more advanced, intelligent, and automated distribution grid. My testimony on AGIS complements that of Company witness Mr. Michael C. Gersack who provides the policy goals of AGIS and that of Mr. David C. Harkness who describes that integration of the AGIS components into the Company's existing systems.

In addition, I address the Company's Electric Vehicle (EV) programs, and discuss the EV capital and O&M expenses included under the Distribution budget for 2020 to 2022. 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 discuss methods to determine electric losses on the distribution system.

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* – AGIS Initiative
- *Section VI* – Electric Vehicle Programs
- *Section VII* – LED Street Lights
- *Section VIII* – Minimum System Study and Zero Intercept Analysis
- *Section IX* – Distribution System Losses
- *Section X* – 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 is comprised of approximately 1,200 feeders, approximately 15,000 circuit miles of overhead conductor on over 500,000 overhead poles and over 11,000 circuit miles of underground cable. This network of feeders connects over 26,000 miles of distribution lines and 240 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 new construction to extend service to new customers or increasing the capacity of the system to accommodate new or increased load, repairing facilities damaged during severe weather to quickly restore service to customers, and performing regular maintenance and repairs on poles, wires, underground cables, metering, and transformers. Our organization is also at the forefront of working to transform the distribution grid as part of the larger AGIS initiative to enhance security, efficiency and reliability, and to safely integrate more distributed resources, support vehicle electrification, and enable improved customer products and services.

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 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. WHAT ARE THE PRIMARY DRIVERS FOR DISTRIBUTION'S CAPITAL ADDITIONS?

A. The Distribution organization is one of the Company's business units whose investments and work directly impact the daily lives of our customers. As a result, it is important that our investments are focused on achieving the Company-wide priorities of reliability, safety, and enhancing the customer experience.

Historically, the overwhelming majority of Distribution's capital budget has been dedicated to maintaining the health and reliability of our facilities through replacement of aging or damaged equipment. During the term of our prior multi-year rate plan (2016 to 2019), we made increasing investments in pole and underground cable replacement to maintain the health of these key components of our system. We also made necessary improvements to provide increased capacity to support growing loads on certain portions of our system.

An example of our commitment to safety and the environment is the LED street light replacement program we recently completed in May 2019. Through this program we converted 85,000 cobra head-style street lights from using high-pressure sodium or mercury vapor lighting to more energy efficient LED lighting across Minnesota. The switch to LED lighting improves safety by improving nighttime visibility for both drivers and pedestrians. I discuss the benefits of this program further in Section VIII of my testimony. Another example of our commitment to safety is our pole replacement program which takes a methodic approach to replacing poles that have reached the end of their useful life. This program ensures that our lines and equipment are supported by quality wood poles.

We demonstrate our focus on the customer experience through our timely response to customer electrical needs. For instance, as the economy grew over the past several years new residential and commercial developments required Distribution to install an increased number of service extensions. We responded to this rise in requests and met our customer's expectation for timely electrical connections. Similarly, we also responded to customer demands to relocate our facilities due to an increased number of road construction projects in the metro area.

Our investments over the term of this multi-year rate plan continue to demonstrate a commitment to the Company's priorities of safety, reliability, and enhancing the customer experience. In the area of reliability, our capital budgets for 2020 to 2022 reflect a focus on maintaining the health of our existing facilities through established asset health and reliability programs with increasing investments in pole replacements. However, additional investment is needed. Our capital budgets during this time period also include investments in our Incremental System Investment (ISI) Initiative. The ISI Initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines.

Our capital budgets over the term of the multi-year rate plan also show increasing strategic investments in the Company's AGIS initiative to advance distribution grid capabilities, increase our system visibility and control, and to enable expanded customer options. From 2020 to 2022, we will invest in the foundational elements of AGIS such as advanced meters, a FAN communication network, FLISR outage detection and restoration, and IVVO voltage improvement. These elements, in concert with future investments, will provide cumulative benefits that will improve the operation and maintenance of the distribution system while also providing an improved customer experience. While we do not know exactly what the future will hold in terms of new technology or customer adoption rates of EVs and distributed solar, we do know that the set of investments that we are proposing here are the right first building blocks.

We are also responding to customer expectations by expanding our EV program. This includes several pilot programs that were recently approved by the Commission, a Fleet EV Service Pilot, a Public Charging Pilot, and a

Residential subscription service pilot, as well as pilots and programs highlighted in the Company's recently filed Transportation Electrification Plan.[1] These investments will provide the infrastructure necessary to promote greater EV use, and to meet the demands of the growing EV market.

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, transformers, and switchgear that have reached the end of their life. This category also captures replacements due to storms and public damage.

Beginning in 2021, the Asset Health and Reliability category will include investments in our ISI Initiative. The ISI Initiative will expand our existing Asset Health programs, such as cable replacement, and establish new programs, such as targeted undergrounding, to address the health, reliability, and resiliency of the portion of the distribution system that is closest to our

[1] *Xcel Energy's Transportation Electrification Plan*, Docket No. E999/CI-17-879 (June 28, 2019).

customers. Additionally, portions of the ISI Initiative will further customer choice by improving elements of the grid closest to our customers that can improve the ability to host additional DER such as distributed solar or EVs. The ISI Initiative is discussed in more detail below.

AGIS: Traditionally, investments that advance the grid were budgeted in the Asset Health category. This is because when we sought to replace aging equipment with new equipment we also evaluated whether the functionality of a particular asset could be or should be enhanced to promote grid modernization. For instance, we replaced electro-mechanical relays with solid-state relays, which are not only communication enabled –but are also capable of providing fault data to allow us to more quickly identify faults on our system and improve our response time. Beginning in 2019 as we launched our AGIS initiative, we separated these investments into their own budget category of AGIS. The AGIS initiative will improve power reliability, reduce power outages, integrate increasingly clean energy onto the grid, and empower customers with more information to control and track their energy use. The details of the AGIS initiative are discussed in more detail in Section IV 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.

<u>Capacity</u>: This category includes capital investments associated with upgrading or increasing distribution system 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.

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

<u>Tools and Equipment</u>: This category includes tools, equipment, communication equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets.

<u>Electric Vehicle Program</u>: This category includes the capital costs associated with three EV pilot programs that were approved by the Commission in 2019 – the Fleet EV Service Pilot, the Public Service Pilot, and the Residential EV Subscription Service pilot. The Fleet EV Service Pilot aims to make it easier for large fleet operators like Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis to integrate electric vehicles into their fleets. The goal of the Public Service Pilot is to begin to build a fast charging network at community mobile hubs along major corridors in the

Twin Cities to allow people the ability to quickly charge their EVs away from home. The Residential Subscription Service Pilot is designed to provide a simple, easy-to-understand charging experience while encouraging off-peak charging. Additionally, the Company has included budget information for other pilots and programs we have highlighted in our Transportation Electrification Plan. The EV program is discussed in more detail in Section VI below.

Solar Gardens: 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 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, will be addressed in the Direct Testimony of Company witness Mr. Gary O'Hara for all of the business units of the Company.

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 budgeting process for AGIS/Grid Modernization and

Electric Vehicle Charging Stations categories in separate sections of my testimony when I describe these programs in detail.

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

A. The appropriate annual capital budget for Distribution is based on a partnership between corporate management of overall finances and our business area needs. Company witness Mr. Gregory J. Robinson explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and overall needs of the Company.

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. We identify specific projects, and forecast appropriate funding for routine investments. We utilize a comprehensive forecasting system to budget for and track these costs.

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

A. We begin our budgeting process in October by reviewing the recent summer peak loads to identify new or increased risks. The state of the economy 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. Consequently, our capital budget is rather dependent on economic activity. 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 likely 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 life 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 likely costs of replacing assets that will fail or be damaged based on historical trends. This analysis results in an 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 DOES DISTRIBUTION ACCOUNT FOR ROUTINE WORK THAT MUST BE PERFORMED EACH YEAR?

A. The nature of the distribution system is that we must account for those regular, common capital additions needed to support new business growth, system reinforcements, or rebuilds. This routine work can also include material upgrades to the distribution network, such as reconductoring a line, upgrading a distribution transformer, or replacing a substation regulator. The two largest categories of routine capital additions are cable replacements and transformer purchases.

As I will discuss, our budgeting process provides us with the flexibility to efficiently allocate funds for performing core business functions, such as connecting new customers, reconstruction of facilities, street light expenditures, purchasing new meters, and transformers. These routine work order accounts generally include the following categories of capital additions: Asset Health and Reliability, New Business, Mandates, and Tool and Equipment purchases.

Q. HOW DOES DISTRIBUTION DEVELOP A BUDGET FOR ROUTINE WORK ORDERS?

A. The budget for new service routine work orders is developed using a cost-per-meter methodology. This process begins with developing a forecast for the number of new meter sets for each local operating area. Inputs and assumptions are also developed that reflect inflation factors used in determining the assumed increase or decrease in the components that comprise the new service costs. These factors (labor, non-labor, contractor, material, equipment, bargaining labor increases and corporate overhead rates) reflect both corporate and operating company rates. Historical data is used to determine the major drivers or components that make up new business costs. The components are: labor (both Company and contracted), labor loadings, material (excluding meters and transformers), equipment, transportation, overheads, and other costs.

Using these components, we then develop a cost-per-meter for each local operating area. This provides us with the ability to apply the related inflation factors to the specific components that make up the overall cost-per-meter. The Distribution business unit also uses this data for variance analysis against what actually occurred during the year. The variance analysis allows us to determine which components account for the difference in the forecast versus actual expenditures.

After the preliminary forecasts estimating our new service needs have been determined, the data is reviewed with our management to determine if there will be substantial changes in the operations (e.g., crew mix, major projects, and labor issues). Depending on the outcome of these reviews, adjustments are made to the preliminary forecast and the proposed routine work order budgets are then submitted for final approval.

Equipment purchases and street light budgets also track with economic activity. We utilize similar forecasting techniques to determine our budget for these routine work orders.

For electric reconstruction routine work orders that address mandates and asset health issues, we use averages of historical values escalated by the corporate inflation rate (around two percent per year) to determine expected levels of spend. This total expected routine work order budget is then allocated to each service area using the average historical ratio of the past five years. The allocation is adjusted to ensure unique, one-time projects in a service area do not impact the calculation of the average five-year historical expenditures.

Q. HOW ACCURATE IS THIS BUDGETING PROCESS FOR ROUTINE PROJECTS?

A. The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, as discussed above, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THIS BUDGET REPRIORITIZATION WORKS?

A. If we have a significant increase in Mandates (relocations) in a given year, this may cause us to have to decrease funding in other areas. Our work on these required relocations – even when we have been given very short notice – cannot be deferred due to our contractual obligations. To maintain investment levels we must defer controllable projects which can reasonably be reduced upon short notice. Asset Health and Reliability projects such as cable replacement fit this criterion and may receive less funding in a given year due to the need to increase funding related to mandated relocations.

Q. WHAT HAPPENS WHEN CABLE REPLACEMENT WORK IS DEFERRED?

A. We have developed and employ criteria to ensure we prioritize cable replacement to most effectively and efficiently improve our customer reliability experience. Specifically, we prioritize our cable replacements by those that are most likely to fail again and would impact the largest number of customers when they do fail. When funding is reduced, we reexamine and reprioritize replacements to ensure we focus on the most effective replacements and defer until the following year those cables that are least likely to imminently sustain a subsequent failure.

Q. HOW DOES THE DISTRIBUTION BUSINESS AREA ESTABLISH BUDGETS FOR NON-ROUTINE PROJECTS?

A. In addition to our routine work orders, the Distribution business area also budgets for and implements certain discrete projects that are identified to address a particular need that does not reoccur each year. At a high level, the identification and assessment of problems or "risks" along with their related solutions or "mitigations" is integral to identifying larger projects we must fund in addition to the work I describe above.

Risks are issues that can result in negative consequences to the Company's ability to provide safe and reliable service. Mitigations are solutions that address the risks. To help ensure that each risk is being addressed by the most efficient solution, we assess all mitigation alternatives and select the one that provides the best value to our customers and our Company.

Q. HOW ARE INDIVIDUAL RISKS AND MITIGATIONS IDENTIFIED AND DEVELOPED?

A. As capital spending is determined and, throughout the year as new issues are identified, each operating area and supporting engineer brings risks (problems) and mitigations (solutions) forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into RiskRegister, a software tool developed by the Company and used to track and rank projects based on the inputs provided. Individual project requests must include specific information regarding their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors that are used to score the identified risks and proposed mitigations are as follows:

- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities;
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated;
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable;
- *Legal* – Evaluation of compliance before and after the risk is mitigated; and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc., and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked.

Q. AFTER INDIVIDUAL PROJECTS ARE RANKED, HOW DOES DISTRIBUTION DETERMINE WHICH PROJECTS TO FUND?

A. Funding for projects is not unlimited and typically the cost for identified individual projects exceeds available funding. In addition, the volume and diverse types of risks require utilization of a systematic process to perform specific risk assessment of the asset's overall future performance expectations. Therefore, it is important to rank or prioritize proposed individual projects before authorizing a project to move forward. This is accomplished by ranking the assessment of each project against each other. Highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers.

Q. HOW ARE AUTHORIZED FUNDING GUIDELINES DETERMINED AND APPLIED?

A. The capital expenditure guidelines are determined at the corporate level for Distribution as explained by Mr. Robinson. Capital expenditures associated with non-discretionary projects are included in the budget first, and then any authorized spending is targeted at discretionary projects based on their ranking.

By including both routine work orders as well as specific projects in our capital budget, we are able to meet the immediate needs of our customers while also proactively addressing system needs as budgeted funds allow. Further, this process provides for flexibility in reallocating our capital budget to address changing system needs and system emergencies.

Q. PLEASE DESCRIBE THE CAPITAL EXPENDITURES BUDGET APPROVAL PROCESS.

A. Capital projects that have been approved for funding are uploaded into our budgeting software. The Operations President's executive management team reviews and approves this list. After the business area has been afforded the opportunity to make adjustments, the capital projects are available for corporate approval. After receiving approval from the Board of Directors, work release plans are finalized and work can be deployed.

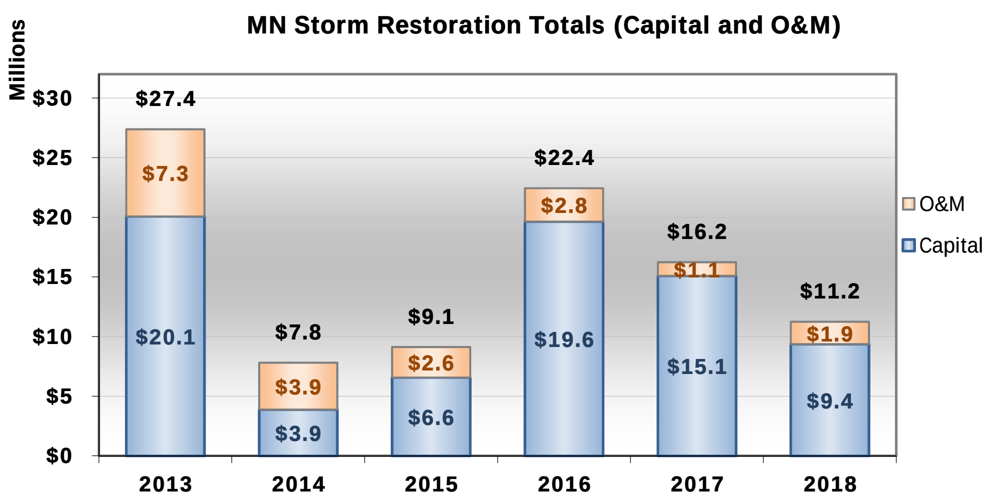
Q. HOW IS THE CAPITAL EXPENDITURE BUDGET IMPLEMENTED AFTER APPROVAL?

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 and result 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 below depicts how our capital and O&M storm restoration spend is uneven year to year due to the unpredictable nature of storms. In certain years, such as 2016, the frequency and severity of severe weather requires us to reallocate portions of our budget from another area to fund increased storm restoration. Xcel Energy's storm response is industry-leading and our ability to reallocate our budgets allows us to promptly restore our customers' electric service as quickly as possible.

Figure 1



C. Distribution's 2016-2019 Capital Investment Trends

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

A. Distribution capital investments were driven by the key strategic goals of reliability, resilience, safety, and enhancing the customer experience. Specifically, Distribution maintained steady investments in Asset Health and Reliability focusing on cable and pole replacements to maintain these facilities that are critical to the reliability of our system. During this time, Distribution also saw an increase in Mandate projects due to the need to relocate our facilities to accommodate road construction projects by the City of Minneapolis on Nicollet Mall as well as 8th Street. Distribution also saw an increase in New Business due to significant new development in Minneapolis near the U.S. Bank Stadium.

Q. PLEASE PROVIDE A BREAKDOWN OF HOW THE COMPANY'S INVESTMENTS FELL INTO THE CAPITAL BUDGET CATEGORIES.

A. Table 1 and Figure 2 provide a breakdown of our capital expenditures by capital budget grouping for 2016 to 2018. Table 2 and Figure 3 below provide a breakdown of our capital additions by capital budget grouping for 2016 to 2018.

Table 1
2016-2018 Actual Capital Expenditures
(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2016	2017	2018
Asset Health & Reliability	$79.6	$79.5	$89.9
Capacity	$23.3	$16.4	$15.1
Mandates	$30.2	$13.7	$28.8
New Business	$53.2	$68.6	$70.5
Solar	$9.0	$4.8	($11.4)
Tools and Equipment	$7.7	$3.7	$2.7
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$0.4
Total	**$203.0**	**$186.6**	**$196.0**

Figure 2

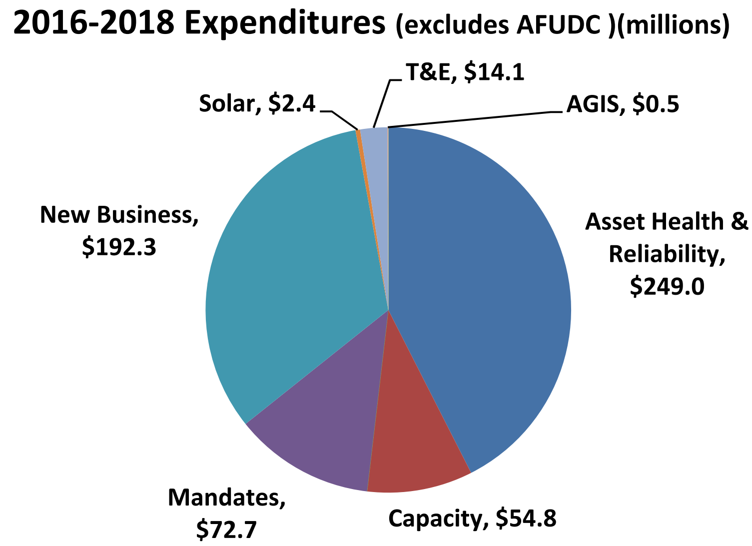


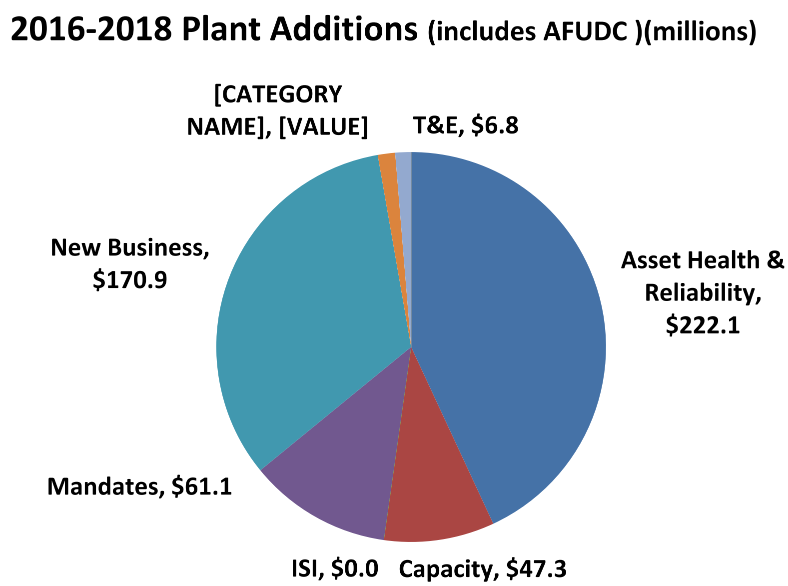
Table 2

2016-2018 Actual Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2016	2017	2018
Asset Health & Reliability	$68.0	$69.7	$84.4
Capacity	$20.1	$17.0	$10.1
Mandates	$26.7	$12.7	$21.7
New Business	$51.2	$56.2	$63.5
Solar	$11.4	($7.0)	($11.8)
Tools and Equipment	$4.3	($0.2)	$2.7
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$0.0
Total	**$181.7**	**$148.5**	**$170.6**

Figure 3



Q. WHAT WERE THE PRIMARY DRIVERS OF THE VARIATIONS IN INVESTMENT IN THESE GROUPINGS OVER THE 2016 TO 2018 TIMEFRAME?

A. Overall capital additions and expenditures fluctuated throughout the 2016 to 2018 timeframe due to the year to year variability of our investments in the Capacity and Mandates categories, along with timing issues for debits and credits within the Solar grouping.

Capital additions in the Capacity category tend to fluctuate year to year due to the financial impact of certain large, discreet substation projects. In 2016, we saw an increase in Capacity projects that were needed to minimize transformer overloads, driving capital additions in this category higher in 2016 than in 2017 and 2018. For example, in 2016 we added an additional transformer bank and two new feeder bays at the existing Fiesta City Substation in Montevideo, Minnesota. These upgrades were needed to reduce transformer overloads. When the Company has large Capacity projects, we may reduce spending in other categories, such as Asset Health and Reliability, of our budget to keep overall spending within appropriate limits. As our Capacity projects decreased from 2016 to 2018, we increased our spending in Asset Health and Reliability to bring routine replacements of cable, poles, and substation equipment closer to appropriate levels.

Mandates fluctuate based upon the size and timing of public works projects. Increased capital investments in this grouping from 2016 to 2018 were driven by two road construction projects in downtown Minneapolis – the Nicollet Mall project in 2016 and the 8th Street construction during 2018.

Timing issues for credits and debits within the Solar grouping also impacted our capital additions. Developers reimburse the Company for Distribution's 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. Differences in the timing of when the Company recognizes the capital additions and expenditures compared to when the developers reimburse the Company cause credits (heavy repayment year) and debits (heavy construction year) in the Solar grouping to fluctuate from year to year, although the ultimate result will be net zero because developers are paying 100 percent of the capital costs of the solar program.

As mentioned above, New Business trended upwards from 2016 to 2017 driven in large part by general economic development, new development in the Minneapolis area related to U.S. Bank Stadium, and the conversion of street lights to LED throughout Minnesota.

Q. WHY DO CAPITAL ADDITIONS TOTALS DIFFER FROM CAPITAL EXPENDITURE TOTALS?

A. While the capital addition trend is directly affected by our capital expenditures, the capital additions trend may not exactly match the capital expenditure trend and may fluctuate more depending on the length of time individual projects require to complete and includes allowed funds used during construction (AFUDC) for certain projects. The capital expenditure trend reflects the incremental investment in the project, whereas the capital addition trend reflects the total investment that is placed in service at the conclusion of a project.

Q. CAN YOU ADDRESS DISTRIBUTION'S CAPITAL INVESTMENTS IN 2019 SO FAR?

A. Our capital investments for 2019 are trending higher than recent historic actuals due primarily to increasing investments in the Asset Health and Reliability, Capacity, and Mandate categories.

Asset Health and Reliability trended upward, driven largely by an increased focus on pole replacements. The Company employs a 12-year inspection cycle for its poles. Due to the overall age of the poles on our system, as well as fine tuning of the inspection process and criteria, the number of poles that are identified for replacement has increased steadily since 2012. Identified poles are targeted to be replaced within one year of the inspection.

Capacity projects increased in 2019 due to the need to address transformer overload issues at several substations throughout Minnesota. Through Distribution's High Consequence Risk program, the Company identifies transformers at a higher risk of defect that, due to insufficient excess capacity available from other transformers or connected substations, would cause prolonged outages if they fail. Substation transformer capital additions are driven by the amount of transformers identified as "high risk" through this program each year.

Investments in Mandate projects are increasing in 2019 due to several large city and county road construction projects. Two of the larger projects are the relocation of our facilities due to construction on Hennepin Avenue and 4th Street in Minneapolis.

Capital additions in the AGIS category for 2019 are for the AMI Residential TOU Pilot and associated components of FAN that were previously certified by the Commission in 2018.[2] In 2019, we will also in-service additional geographic information system (GIS) mapping necessary for the operation of ADMS.

Distribution's capital expenditures and capital additions forecasts for 2019 and actuals for 2016 to 2018 are included in Tables 3 and 4.

[2] *In the Matter of Xcel Energy's Residential Time of Use Rate Design Pilot Program*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST (Aug. 7, 2018).

Table 3

2016-2019 Actual and Forecasted Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2016	2017	2018	2019
Asset Health & Reliability	$79.6	$79.5	$89.9	$92.3
Capacity	$23.3	$16.4	$15.1	$19.4
Mandates	$30.2	$13.7	$28.8	$31.3
New Business	$53.2	$68.6	$70.5	$55.5
Solar	$9.0	$4.8	($11.4)	($0.5)
Tools and Equipment	$7.7	$3.7	$2.7	$2.6
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$0.4	$3.8
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.0	$0.8
Total	**$203.0**	**$186.6**	**$196.0**	**$205.1**

Table 4

2016-2019 Actual and Forecasted Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2016	2017	2018	2019
Asset Health & Reliability	$68.0	$69.7	$84.4	$89.0
Capacity	$20.1	$17.0	$10.1	$19.0
Mandates	$26.7	$12.7	$21.7	$29.4
New Business	$51.2	$56.2	$63.5	$56.1
Solar	$11.4	($7.0)	($11.8)	$11.2
Tools and Equipment	$4.3	($0.2)	$2.7	$5.2
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$0.0	$4.2
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.0	$0.8
Total	**$181.7**	**$148.5**	**$170.6**	**$214.8**

D. Overview of Distribution's 2020 to 2022 Capital Investments

Q. WHAT ARE DISTRIBUTION'S CAPITAL FORECASTS FOR 2020-2022 BY CAPITAL BUDGET GROUPING?

A. Our capital expenditure forecasts for 2020 through 2022 are set forth in Table 5 and Figure 4. Our capital additions forecasts for 2020 through 2022 are set forth in Table 6 and Figure 5. Our individual capital additions are listed in Exhibit___(KAB-1), Schedule 2.

Table 5

2020-2022 Forecasted Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2020	2021	2022
Asset Health & Reliability	$108.8	$113.2	$107.6
Capacity	$44.4	$40.1	$32.3
Incremental Customer Investment (ISI) Initiative	$0.0	$81.0	$88.0
Mandates	$28.9	$29.4	$28.5
New Business	$58.9	$63.0	$61.1
Solar	$0.0	$0.0	$0.0
Tools and Equipment	$7.1	$3.8	$4.0
Advanced Grid Intelligence & Security (AGIS)	$10.4	$41.2	$131.9
Electric Vehicle Program (EVP)	$9.5	$8.1	$9.8
Total	**$267.8**	**$379.8**	**$463.2**

Figure 4

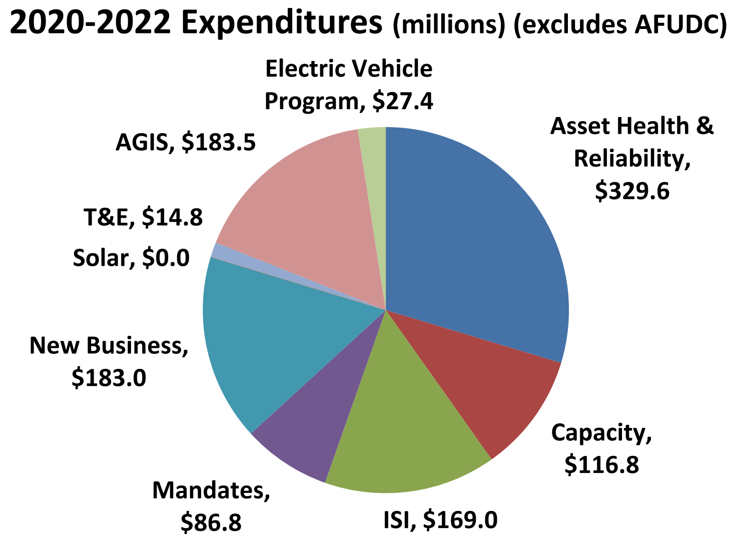


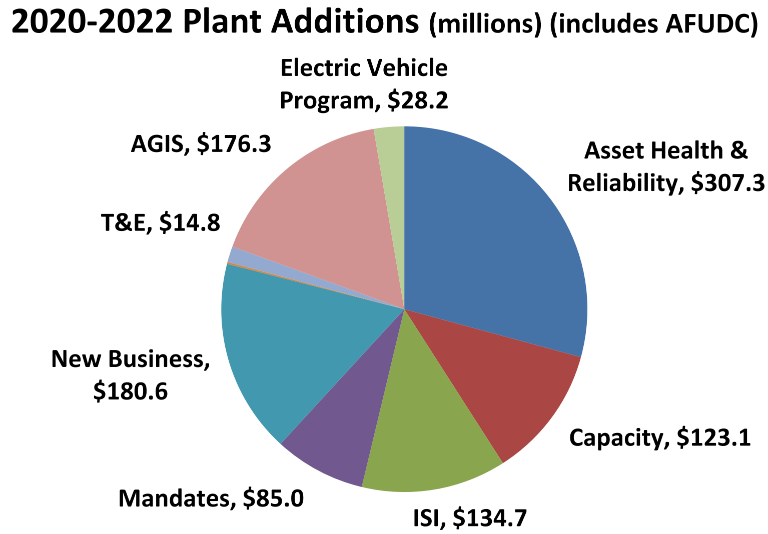
Table 6

2020-2022 Forecasted Capital Additions

(Includes AFUDC)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2020	2021	2022
Asset Health & Reliability	$98.8	$102.7	$105.9
Capacity	$30.8	$54.1	$38.2
Incremental Customer Investment (ISI) Initiative	$0.0	$50.7	$84.0
Mandates	$17.8	$27.6	$39.6
New Business	$57.9	$62.0	$60.7
Solar	$3.9	$0.4	($5.9)
Tools and Equipment	$6.9	$3.7	$4.2
Advanced Grid Intelligence & Security (AGIS)	$9.5	$40.5	$126.3
Electric Vehicle Program (EVP)	$9.8	$8.3	$10.1
Total	**$235.3**	**$350.0**	**$463.1**

Figure 5



Q. HOW DO DISTRIBUTION'S CAPITAL ADDITIONS FOR 2020 TO 2022 COMPARE TO HISTORIC TRENDS?

A. The vast majority of the changes between Distribution's historic capital investment trends and the 2020 to 2022 forecast are driven by the increasing investments in AGIS, the ISI Initiative, and our EV Programs. I discuss AGIS in Sections V of my testimony and the EV Programs in Section VI. The ISI Initiative is discussed with our other Asset Health and Reliability investments below.

Of the pre-existing capital groupings for Distribution, the 2020 to 2022 forecasted capital additions for Mandates, Solar, and Tools and Equipment are relatively flat compared to historical trends. New Business capital additions trend slightly upward to reflect assumed customer growth, and then remains fairly steady from 2021 to 2022.

Asset Health and Reliability capital additions increase in 2020 and 2021, before declining in 2022. This increase is driven by additional pole replacements due to increased inspection coupled with goals to eliminate the backlog of pole replacements in 2020 and 2021.

Capacity capital additions are forecast to increase significantly in 2020 and then decline in 2021 and 2022. This increase is driven by the timing of several large capacity projects that are planned to be placed in service in 2021, which are described in more detail below.

Q. CAN YOU PROVIDE AN OVERALL VIEW OF DISTRIBUTION'S CAPITAL INVESTMENT TREND FROM 2016 TO 2022?

A. Yes. Our overall 2016 to 2022 capital expenditures and capital additions are set forth in Tables 7 and 8 below.

Table 7

2016-2022 Actual and Forecasted Distribution Capital Expenditures

(Excludes AFUDC; Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2016	2017	2018	2019	2020	2021	2022
Asset Health & Reliability	$79.6	$79.5	$89.9	$92.3	$108.8	$113.2	$107.6
Capacity	$23.3	$16.4	$15.1	$19.4	$44.4	$40.1	$32.3
Incremental Customer Investment (ISI) Initiative	$0.0	$0.0	$0.0	$0.0	$0.0	$81.0	$88.0
Mandates	$30.2	$13.7	$28.8	$31.3	$28.9	$29.4	$28.5
New Business	$53.2	$68.6	$70.5	$55.5	$58.9	$63.0	$61.1
Solar	$9.0	$4.8	($11.4)	($0.5)	$0.0	$0.0	$0.0
Tools and Equipment	$7.7	$3.7	$2.7	$2.6	$7.1	$3.8	$4.0
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$0.4	$3.8	$10.4	$41.2	$131.9
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.0	$0.8	$9.5	$8.1	$9.8
Total	**$203.0**	**$186.6**	**$196.0**	**$205.1**	**$267.8**	**$379.8**	**$463.2**

Table 8

2016-2022 Actual and Forecasted Distribution Capital Additions

(Includes AFUDC; Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2016	2017	2018	2019	2020	2021	2022
Asset Health & Reliability	$68.0	$69.7	$84.4	$89.0	$98.8	$102.7	$105.9
Capacity	$20.1	$17.0	$10.1	$19.0	$30.8	$54.1	$38.2
Incremental Customer Investment (ISI) Initiative	$0.0	$0.0	$0.0	$0.0	$0.0	$50.7	$84.0
Mandates	$26.7	$12.7	$21.7	$29.4	$17.8	$27.6	$39.6
New Business	$51.2	$56.2	$63.5	$56.1	$57.9	$62.0	$60.7
Solar	$11.4	($7.0)	($11.8)	$11.2	$3.9	$0.4	($5.9)
Tools and Equipment	$4.3	($0.2)	$2.7	$5.2	$6.9	$3.7	$4.2
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$0.0	$4.2	$9.5	$40.5	$126.3
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.0	$0.8	$9.8	$8.3	$10.1
Total	**$181.7**	**$148.5**	**$170.6**	**$214.8**	**$235.3**	**$350.0**	**$463.1**

Both 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. At the same, Distribution's capital investment levels may increase in years when we are working on major initiatives, such as AGIS, and capital additions necessarily increase when those initiatives are placed in service.

Q. SHOULD CUSTOMERS BE CONCERNED THAT SPECIFIC PROJECT NEEDS AND PLANS WILL LIKELY EVOLVE DURING PARTICULAR YEARS OF THE MULTI-YEAR PERIOD?

A. No, sometimes Distribution needs to make adjustments to our capital budgets to respond to emerging customer and business needs. For instance, the severe weather in a particular year may require higher spending on storm restoration than what was included in the budget. Similarly, there may be a greater number of Mandate projects in a given year than was anticipated during the budgeting process. Both of these instances would require Distribution to shift our investment strategy to meet these emerging needs while still maintaining a reasonable total capital investment amount.

Q. WHAT DO YOU CONCLUDE ABOUT DISTRIBUTION'S 2020 TO 2022 CAPITAL INVESTMENTS FORECASTS?

A. While the level of capital investments that Distribution seeks to recover in this rate case are higher than historic 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. As a result, these forecasts can be relied on to set just and reasonable rates for our customers.

E. Major Planned Investments for 2020 to 2022

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

A. This section of my testimony discusses the major planned investments Distribution anticipates in 2020 through 2022.

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.

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 2020 to 2022. The first major planned investment is the deployment of 1.3 million AMI meters in Minnesota which will commence in the third quarter of 2021 and will continue through 2024. This full deployment of AMI builds off the limited installation of AMI meters planned for installation in late 2019 as part of the TOU pilot certified by the Commission.[3] These AMI meters will replace our existing AMR system that is reaching the end of its contract and

[3] *In the Matter of Xcel Energy's Residential Time of Use Rate Design Pilot Program*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST, (Aug. 7, 2018).

will no longer be supported by the vendor after 2026. The AMI meters will also provide value to our customers through the increased visibility and information provided by AMI that will allow for greater energy usage insights, reliability improvements, and enhanced rate and DSM offerings. AMI will also provide benefits for the Company by enhancing utility planning and improved operational capabilities. This AMI deployment is one component of the Company's larger AGIS initiative and is discussed in detail in in Section V of my testimony.

The second major planned investment is the ISI Initiative in our Asset Health category that builds off of many of Distribution's existing routine projects in the area of Asset Health to increase investments to address common causes of outages such as cable failures and pole fires. This initiative divided into four subcategories of (1) substation programs, (2) underground programs, (3) overhead tap programs, and (4) overhead mainline programs. These investments would provide several benefits to customers, including improving reliability (both storm normalized and non-storm normalized), resiliency, and power quality, and enabling increased adoption of DER such as PV and EVs.

F. Key Capital Additions for 2020 to 2022

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 $5 million or more in capital additions between 2020 and 2022. These projects are described in detail below. Unless otherwise stated, all dollar figures are at the NSPM level.

The State of Minnesota jurisdictional amounts for these capital additions are included 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. Distribution's investments in Asset Health and Reliability fall into two categories – routine projects and larger specific 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, wood poles, overhead lines, substation equipment, transformers, and switchgear 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 non-routine discrete Asset Health and Reliability projects that address asset renewal (aging infrastructure – 4 kV conversions for example) or reliability (age of facilities impacting reliability/customer outages/failures, etc.). Projects are identified based on system needs, and are scored based on our standard budgeting processes and evaluated for funding based on risk score, need, and available funding. Due to the timing of in-service dates the capital additions for these non-routine discrete projects varies on a year-to-year basis.

Table 9

2016-2022 Actual and Forecasted Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2016	2017	2018	2019	2020	2021	2022
Asset Health and Reliability							
Incremental Customer Investment (ISI)	$0.0	$0.0	$0.0	$0.0	$0.0	$50.7	$84.0
Non-Routine Discrete	$5.3	$1.3	$10.0	$8.0	$12.7	$2.2	$9.6
Routine Rebuilds, Conversions & Programs	$23.6	$35.9	$31.6	$35.5	$30.9	$40.2	$40.2
Routine Cable Replacement	$15.8	$15.2	$23.3	$19.7	$20.0	$30.5	$26.5
Routine Restoration/Failure Reserves	$21.6	$17.0	$11.0	$12.7	$9.7	$13.2	$13.9
Routine Pole Replacements	$1.7	$0.3	$8.6	$13.1	$25.4	$16.6	$15.7
Total	**$68.0**	**$69.7**	**$84.4**	**$89.0**	**$98.8**	**$153.4**	**$189.9**

Q. TABLE 9 SHOWS INCREASING CAPITAL ADDITIONS IN THE ASSET HEALTH AND RELIABILITY CATEGORY BETWEEN 2020 AND 2022. WHAT IS DRIVING THIS INCREASE?

A. The vast majority of the increasing capital additions in the Asset Health and Reliability category are due to the ISI initiative, which is driven by the need to improve reliability on those elements of the system that are the closest to our customers as well as provide the infrastructure to support increased DER integration. While historically Distribution has made investments in our infrastructure through our established Asset Health and Reliability programs to ensure the reliability of our system, the utility industry is changing rapidly and customers have new expectations for power availability and reliability. As a result, we believe it is necessary to shift funding closer to those portions of the system that directly connect to customers with the goal of enhancing the safety, reliability, and resiliency of the system while also enabling customer choice and the adoption of DER, such as EVs.

This initiative will both expand existing asset health programs and will create new programs to address areas of the system that have traditionally not received much focus. Specifically, this initiative will expand two of Xcel Energy's existing programs, one that replaces underground cables that are at risk of failure and another that identifies and replaces substation transformers that are nearing the end of their useful life. This initiative will create new programs that focus directly on our customers' reliability and DER adoption needs by expanding investments on the portions of our system closer to the customer. Typically these elements are the taps (radial extensions from our feeders) and secondary voltage systems.

The moderate increase in capital additions for Asset Health and Reliability that are not related to the ISI initiative are driven primarily by increased investment in pole replacements in 2020, and underground cable replacement in 2021 and 2022.

a. Incremental System Investment Initiative

Q. WHAT ARE THE PROGRAMS THAT COMPRISE THE ISI INITIATIVE?

A. ISI initiative is divided into four main programs: the substation programs, the underground programs, the overhead tap programs, and the overhead mainline programs. Within each of these four main programs there are several sub-programs and I will describe each of these programs in greater detail below.

Q. WHAT IS THE OVERALL BUDGET FOR THE ISI INITIATIVE?

A. The capital additions for the ISI Initiative for 2020 to 2022 are provided in Table 10 and are broken down by the four main programs. The O&M costs associated with the ISI Initiative are provided in Table 11. I note that these O&M costs are also included in the overall Distribution O&M budget which is discussed in Section VII of my testimony.

Table 10

ISI Capital Additions – Distribution State of MN Electric Jurisdiction (Dollars in Millions)			
ISI Programs		**2021**	**2022**
Overhead Tap Programs	Targeted Undergrounding	$11.0	$24.0
	Low Cost Reclosers	$2.2	$2.5
	Pole Top Reinforcements	$2.2	$2.5
	Transformer and Secondary Replacements	$2.0	$2.5
	High Customer Count Taps	$2.4	$3.0
	Community Resiliency	-	$2.4
Underground Programs	Mainline Cable Replacement	$4.2	$9.0
	Underground Residential Distribution (URD) Cable Replacement	$2.0	$2.5
	Cable Asset Life Extension Program	$4.0	$6.0
	Network Monitoring	-	$1.0
	St. Paul Tunnel Rehabilitation	$3.0	$3.0
	Feeder Exit Capacity	$2.0	$3.0
	Purchases / Tooling	$4.5	$0.2
Substation Programs	Transformer Replacement	$5.0	$14.0
	Substation Asset Renewal	$3.4	$4.9
Overhead Mainline Programs	Pole Fire Mitigation	$2.0	$2.5
	Lightning Protection Replacement	$0.8	$1.0
TOTAL		**$50.7**	**$84.0**

Table 11

ISI O&M Costs-Distribution State of MN Electric Jurisdiction (Dollars in Millions)			
Cost Category	**2020**	**2021**	**2022**
O&M Expense	$1.1	$1.1	$1.1
Total	**$1.1**	**$1.1**	**$1.1**

(1) Overhead Tap Programs

Q. DESCRIBE THE OVERHEAD TAP PROGRAMS.

A. These programs seek to improve reliability and resiliency of the Company's electric distribution system through a series of six programs that target the overhead tap lines throughout the Minnesota service territory. These six programs are: (1) targeted undergrounding; (2) low cost reclosers; (3) pole top reinforcements; (4) transformer and secondary replacement; (5) high customer count taps and (6) community resiliency program. The capital additions for each of these six programs are provided in the table below.

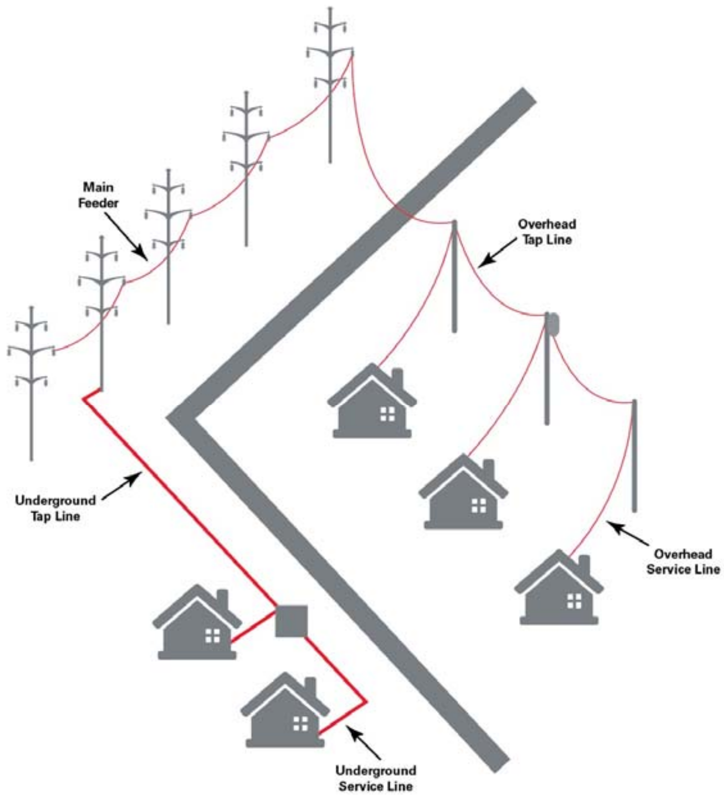
Table 12

ISI Capital Additions – Distribution State of MN Electric Jurisdiction (Dollars in Millions)				
ISI Programs		2020	2021	2022
Overhead Tap Programs	Targeted Undergrounding		$11.0	$24.0
	Low Cost Reclosers		$2.2	$2.5
	Pole Top Reinforcements		$2.2	$2.5
	Transformer and Secondary Replacements		$2.0	$2.5
	High Customer Count Taps		$2.4	$3.0
	Community Resiliency		-	$2.4
TOTAL			**$19.8**	**$36.9**

Q. WHAT ARE OVERHEAD TAP LINES?

A. As shown on Figure 6 below, tap lines are those that split off from the main feeder and travel through neighborhoods to connect to homes and businesses. The tap portion of the NSPM distribution system consists of nearly 22,500 circuit miles of line. Of those, approximately 58 percent, or 13,050 miles are overhead.

Figure 6



Q. WHAT IS THE PRIMARY GOAL OF THE OVERHEAD TAP PROGRAMS?

A. The primary goal of all of the overhead tap programs is to improve reliability and resiliency of the Company's electric distribution system. Specific to reliability, we intend this program to decrease the number of outages per year for those customers that experience frequent and long outages due to issues on the overhead tap system. As our customers live and work near the electrical system and its equipment and components, we also consider community aesthetics a factor of our customers' experience. Customer satisfaction depends on a Company's ability to meet customer expectations. Reliability is one of the foundational components for meeting customer expectations of an electric utility, and as electricity becomes increasingly entwined with every aspect of day-to-day life, the issue of reliability becomes increasingly important to customers.

With regard to distribution system resiliency, these programs aim to strengthen the electrical system to reduce weather-related impacts and outages, rather than the traditional focus on ensuring rapid response and restoration to a storm-vulnerable system. Community resiliency includes ensuring the most critical first responder services in a community are supplied by a safe, reliable, and storm-hardened grid system in the event of emergency. Additionally, we need to prepare our system for electric vehicle penetration in advance of rapid and widespread customer adoption.

Q. HOW DOES THE COMPANY TRACK DISTRIBUTION SYSTEM RELIABILITY?

A. The most common industry metrics for tracking reliability performance are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), which are tracked both on all days and on a normalized basis to exclude major storm events. While SAIDI and SAIFI provide a metric for tracking the overall performance of the system, they do not capture the reliability experience of each individual customer. For tracking the individual customers' experiences, the Company has a Customer Experiencing Multiple Interruptions (CEMI) metric that identifies customers that experiences multiple outages within a year, no matter the duration. The overhead tap program aims to decrease the number of outages per year for those customers that experience frequent and long outages due to issues on the overhead tap system.

Q. PLEASE PROVIDE AN EXAMPLE OF A COMMUNITY THAT WOULD BENEFIT FROM THE PROPOSED OVERHEAD TAP PROGRAMS.

A. The area near the intersection of Skyview Drive and Judicial Road in Burnsville, Minnesota, is a good example of a community that would benefit from one or more of the overhead tap programs. This area is heavily wooded and since 2016, this neighborhood has experienced several widespread power outages due to trees or large branches failing into conductors or damaging to overhead tap equipment during storm events.

For instance, on July 5, 2016, a thunderstorm with winds in excess of 60 miles per hour downed many trees and broke over 100 poles and crossarms across the metro area. In total, over 250,000 customers were affected by this storm and approximately 1,600 full time employees and contractors worked to restore power system wide. As a result, 141 customers in this Burnsville neighborhood experienced an outage for over 17 hours.

On June 11, 2017, another thunderstorm downed trees, poles, and wires across the Company's service territory. Over 29,000 Minnesota customers' were impacted by this storm and about 200 full time Xcel Energy employees and contractors worked to restore power as quickly as possible. This same Burnsville neighborhood of 141 customers experienced an outage of over 24 hours due to this storm.

On June 30, 2019, another strong storm with winds in excess of 60 miles per hour downed trees, poles, and wires across the Company's service territory and about 225 full time employees and contractors worked diligently to restore power. This Burnsville neighborhood was without power for just over 23 hours.

Q. HOW WOULD THE OVERHEAD TAP PROGRAMS HAVE BENEFITED THIS BURNSVILLE NEIGHBORHOOD DURING THE STORM EVENTS YOU DISCUSSED ABOVE?

A. The Company's overhead tap programs are designed to strengthen and improve the service of customers currently served by overhead tap lines, like the Burnsville neighborhood to minimize damage during storm events like those highlighted above. The proposed projects include a targeted undergrounding program, evaluating and redesigning tap lines serving a large number of customers, replacing smaller overhead transformers and replacing open-wire secondary, replacing poles with aged and degraded components, as well as identifying key community resiliency areas that would benefit from an electrical system redesign to improve continuity during emergency events. I will discuss the goals and benefits of each of the programs in more detail below.

(a) Targeted Undergrounding

Q. WHAT IS THE GOAL OF THE TARGETED UNDERGROUNDING PROJECT?

A. The goal of the targeted undergrounding program is to underground the outage-prone tap lines to reduce the likelihood of these outages and to enable our crews to focus restoration efforts on other areas of the system allowing for quicker response times for all customers. The primary benefit of this program is that by undergrounding the tap lines with the highest failure rate, we significantly improve the reliability of those tap lines for customers – and overall, we improve the resilience of the system because there will be fewer downed tap lines. Fewer downed tap lines means that restoration crews can focus efforts elsewhere during weather events and likely improve restoration times for other areas of the system. Also, since this targeted undergrounding will focus on areas with heavy vegetation, there will be a reduced need for vegetation management in these areas.

NSPM has over 13,100 miles of overhead miles of tap lines in Minnesota. In relation to the underground tap system, failures on the overhead tap system occur 1.5 times more frequently, primarily driven by storm and weather events. Overhead power line segments with a history of high numbers of outages drive a disproportionate amount of outages that affect Xcel Energy's customers. These are typically segments of line that are aging and/or located in heavily vegetated areas. While we have systematic programs that manage vegetation to industry standard clearances, and where we replace components of our system, including conductor, that are aging or experiencing abnormal failure rates, approximately 17 percent of our overhead tap lines in Minnesota are an older vintage of conductor that generally have a higher failure rate compared to newer overhead lines.

Q. HOW WILL THE TARGETED UNDERGROUNDING PROGRAM BE IMPLEMENTED?

A. We propose to start the targeted undergrounding program with several pilot areas – undergrounding 20 miles of overhead tap system in 2021 and 30 miles in 2022. These pilots will focus primarily on areas that have experienced outages with high quantities of tap outages due to vegetation. As the program matures, the Company expects to consider areas based on multiple criteria including but not limited to: interruption rates, interruption length, degraded infrastructure, and location of overhead line.

(b) Low Cost Reclosers

Q. DESCRIBE THE LOW COST RECLOSER PROGRAM.

A. A recloser is a breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. Our current tap lines are predominantly equipped with fuses that, if opened, result in a sustained outage for both permanent and temporary causes. The low cost recloser program would reduce sustained outages by installing reclosers on tap lines.

Low cost reclosers are single-phase devices, generally mounted in existing fuse holders. While they prevent sustained outages from temporary causes such as a tree branch falling into an overhead line, they lack the full capabilities of traditional reclosers – including the capacity and three-phase attributes of reclosers used on mainlines and with FLISR systems.

Q. WHAT ARE THE BENEFITS FOR CUSTOMERS OF THE LOW COST RECLOSER PROGRAM?

A. Based on industry averages and internal reliability information it is estimated that 70 percent of overhead line failures are temporary and can prevented by installing a recloser. NSPM has an estimated 61,500 fuse locations with 12,500 fuses that have opened due to a fault at least once in the past three years. By replacing these fuses with reclosers, reliability will be improved as these devices will prevent sustained outages from temporary causes. In addition, these low cost reclosers will reduce O&M expenses as crews will not need to be deployed to replace the fuse. While this will prevent a sustained outage, customers will experience a momentary outage as the fault clears.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE LOW COST RECLOSER PROJECT?

A. The Company plans to install up to 500 low cost reclosers in 2021 and 2022.

(c) Pole Top Reinforcement

Q. DESCRIBE THE POLE TOP REINFORCEMENT PROGRAM.

A. This program will improve the reliability and resiliency of the system by increasing our investment in identification and replacement of pole top equipment and poles (due to pole top degradation) that have reached the end of their useful life. Pole top equipment includes cross-arms, braces and insulators. Such equipment is a major contributor to outages and storm related interruptions. Every year, our pole inspection program flags approximately 2,500 potentially degraded components that can be mitigated – and where doing so will increase system resilience. Some of this mitigation is being done currently as part of our pole replacement program. This program however, will broaden and extend the reach of that program to replace other pole top equipment based on performance history, condition, vintage, and other factors.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE POLE TOP REINFORCEMENT PROGRAM?

A. The Company plans to reinforce the equipment on up to 900 poles in 2021 and 2022.

(d) Transformer and Secondary Replacement

Q. DESCRIBE THE TRANSFORMER AND SECONDARY REPLACEMENT PROGRAM?

A. This program will improve customer reliability and resiliency of the system through replacement of aging secondary wire that is degraded and at risk of failure, and distribution transformers throughout the system that are undersized and at risk of overloads.

Many of the transformers and secondary systems were designed many decades ago when home electric usage mainly consisted of lighting and appliances and did not contemplate the increased adoption of air conditioners, electric vehicles, and on-site solar. The addition of these new devices changes the amount of energy consumed by customers and in many cases is higher by several multiples than the equipment was designed to handle. This increase can lead to overloads on distribution transformers and low voltage at the customer's service.

Q. ARE THERE SPECIFIC TYPES OF TRANSFORMERS THAT ARE AT A GREATER RISK OF OVERLOAD?

A. Yes. Those transformers that are at the greatest risk for overload are: (1) 25 kVA and smaller transformers, (2) transformers that are already overloaded during peak periods, (3) and transformers with more than 11 customers. We will solve the risks by either increasing the size of the transformer and secondary wires as appropriate, or adding an additional transformer and dividing the customer load between the two. Proactive replacement and upgrade of this equipment will enable DER/EV adoption by our customers.

We have approximately 31,500, 25 kVA transformers that serve 195,000 customers and over 15,900 transformers that are overloaded during peak periods and have more than 11 customers connected to them. In addition to mitigating outage risk, replacing these distribution transformers with higher capacity transformers will increase system resilience, allowing for more easily accommodating DER. As customers move to DER and EV technology, increases in the penetration of these loads may overload the current transformer serving several homes.

This program will also replace older open wire secondary - especially the small wire (#4, #6). We estimate there are nearly 3,300 miles of small open wire secondary in the NSPM operating company. The lower capacity of these smaller wires will often lead to voltage issues – and as electric vehicle penetration increases, and overloading can manifest itself as a reliability impact.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE TRANSFORMER AND SECONDARY REPLACEMENT PROGRAM?

A. The Company plans to replace the transformer and the associated secondary wire at up to 150 locations in 2021 and 2022.

(e) High Customer Count Taps

Q. DESCRIBE THE HIGH CUSTOMER COUNT TAPS PROGRAM.

A. The greatest benefit of this program will be increased reliability for our customers by redesigning taps with the greatest value potential for improvement in terms of number of customers, outage history, and implementation cost. The industry has found one of the easiest methods to improve the customer reliability experience is to increase the number of protective devices, thus reducing the number of customers "behind" each device. This program focuses on redesigning the tap portion of the distribution system to reducing the number of customers that are located behind the protective device to an average of 40 to 50 customers. Redesigns will generally employ one of three solutions – adding phases, interjecting another source, or subdividing the tap.

Q. WHAT ARE THE CUSTOMER BENEFITS OF THE HIGH CUSTOMER COUNT TAPS PROGRAM?

A. Currently, there are approximately 20,000 failures per year on the tap portion of the system that result in an outage for customers. Taps with over 100 customers are responsible for approximately 50 percent of the tap-level SAIDI impact, yet they only represent around 10 percent of the total number of taps. By decreasing the number of customers per tap, we expect that fewer customers will be impacted by outages.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE HIGH CUSTOMER COUNT TAP PROGRAM?

A. The Company plans to address up to 200 different high customer count taps in both 2021 and 2022.

(f) Community Resiliency

Q. DESCRIBE THE COMMUNITY RESILIENCY PROGRAM.

A. This program would fund projects that would benefit our customers by providing resiliency during a prolonged or widespread outage. The program involves working with communities to identify strategic locations, such as a community center or facility that provides essential services, where we would provide additional back-up power during an extended outage. Such projects would likely consist of a microgrid that would combine DERs – energy storage (most likely batteries), local generation and other DER such as demand response – and the necessary equipment and controls to safely isolate a subset of the distribution system. During normal operations, the DER can benefit the distribution systems to address capacity, reliability or other needs.

Q. WHAT ARE THE BENEFITS TO CUSTOMERS FROM THE COMMUNITY RESILIENCY PROGRAM?

A. Local communities will benefit from the various services that the identified facility can provide during an extended outage. Customers will also benefit from value that the DERs can provide during normal grid operations, such as investment deferrals and other needs. The Company will also benefit as lessons learned from these projects will also inform future project specifications and engineering and design requirements, as well as overall value provided to our customers.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2022 FOR THE COMMUNITY RESILIENCY PROGRAM?

A. The Company plans to install the equipment necessary to provide back-up power at one strategic location in 2022.

(2) Underground Programs

Q. WHAT ARE THE UNDERGROUND PROGRAMS THAT ARE PART OF THE ISI INITIATIVE?

A. There are seven underground programs: (1) mainline cable replacement, (2) underground residential distribution (URD) cable replacement, (3) cable asset life extension, (4) network monitoring, (5) St. Paul tunnel work (6) feeder exit capacity work, and (7) tools and equipment. The capital additions for each of these seven programs are provided in the table below.

Table 13

ISI Capital Additions – Distribution State of MN Electric Jurisdiction (Dollars in Millions)				
ISI Programs		2020	2021	2022
Underground Programs	Mainline Cable Replacement		$4.2	$9.0
	Underground Residential Distribution (URD) Cable Replacement		$2.0	$2.5
	Cable Asset Life Extension Program		$4.0	$6.0
	Network Monitoring		-	$1.0
	St. Paul Tunnel Rehabilitation		$3.0	$3.0
	Feeder Exit Capacity		$2.0	$3.0
	Purchases / Tooling		$4.5	$0.2
TOTAL			**$19.7**	**$24.7**

(a) Mainline Cable Replacements

Q. DESCRIBE THE MAINLINE CABLE REPLACEMENT PROGRAM.

A. Cable failures are a main contributor to outages for customers who are served by underground cable facilities. Proactively replacing cable allows us to avoid a potential outage caused by a cable failure and utilize a systematic approach in the replacement of this asset. As a result of our existing asset health cable replacement program, the failure rate for non-jacketed underground cables has been flat to slightly declining since 2013, averaging approximately 0.2 failures per mile each year. However, by making increased investments in cable replacements, the Company expects to reduce this failure rate even further.

Nearly 25 percent of the Company's underground cable in Minnesota is a type of cable (non-jacketed cross-linked polyethylene (XLPE) cable that was installed prior to 1985) that is more prone to failures and has a shorter useful life (approximately 35 years) than newer cable types. To address this issue, we have invested between $14 million and $26 million annually between 2014 and 2018 across Minnesota to replace non-jacketed cable that has failed or reached the end of its life with jacketed cable in Minnesota. Even with these investments, there is still approximately 2,700 miles of non-jacketed primary tap cable (approximately 30 percent of total) and about 250 miles of non-jacketed mainline cable (approximately 15 percent of total) in Minnesota. This program will increase Minnesota investments for mainline cable and primary tap cable per year starting in 2021.

Q. HOW WILL INCREASING THE RATE OF CABLE REPLACEMENT OF NON-JACKETED CABLES BENEFIT CUSTOMERS?

A. Cable replacement can be time-intensive based on the complexity of the location and proximity to major thoroughfare or other utilities and geographical restrictions. When cable begins to fail, it can lead to subsequent failures that can reoccur in rapid succession based on the condition of the asset, thus impacting customers' reliability experience. Proactive replacement allows us to replace the cable before it fails becoming unrepairable and leading to an emergency replacement. Emergency replacements leave the system with less redundancy and switching options, which can lead to lengthy outages if additional failures occur.

Q. ARE THERE OTHER BENEFITS ASSOCIATED WITH THE REPLACEMENT OF UNDERGROUND CABLE FOR RESIDENTIAL CUSTOMERS?

A. Yes. The underground residential distribution (URD) system is comprised of an underground circuit, in a loop arrangement, segmented by distribution transformers. With the URD cable replacement program, we will replace the entire half loop rather than making segment replacement as sections fail. This proactive replacement of the entire half loop will avoid additional failures and outages for all customers located on this half loop.

Q. WHAT WORK WILL BE PERFORMED IN 2021 AND 2022 FOR THE MAINLINE CABLE REPLACEMENT AND URD CABLE REPLACEMENT PROGRAMS?

A. This program will supplement our existing asset health cable replacement program. The Company will replace up to four additional miles of mainline cable in 2021 and up to nine additional miles of mainline cable in 2022. The Company will also replace 10 additional miles of URD cable in 2021 and up to 12 additional miles of URD cable in 2022.

(b) Cable Asset Life Extension Program

Q. WHAT IS THE CABLE ASSET LIFE EXTENSION PROGRAM?

A. The Company's current asset health cable replacement program focuses on replacing those underground cable systems that have had multiple failures. While this strategy has been successful at reducing cable failures, this strategy overlooks proactive assessment of the condition of overall cable population. This program would use a cable assessment technology to assess and rehabilitate cable through use of partial discharge diagnostics to precisely assess the overall condition of the cable system and make recommendations on how to rehabilitate cables to like-new manufacturer standards. Cable systems that meet these standards perform like new and have an expected useful life of an additional 30-40 years after rehabilitation.

Q. WHAT ARE THE CUSTOMER BENEFITS OF THIS CABLE ASSET LIFE EXTENSION PROGRAM?

A. This assessment will allow us to determine precisely what and where defects exist within the cable system and replace only the defective portions of the cable system such as terminations, splices, or other weak points in the cable. This is opposed to a wholesale replacement which replaces portions of the cable that still has years of useful life left. We expect that this will result in improved reliability experience and cost savings for our customers.

With respect to reliability benefits, cable failures are a significant contributor to the customer reliability experience. Also as discussed above, cable failures can be difficult to locate and repair as they are underground and often difficult to access. Through implementation of targeted assessment and replacement of underground cable and associated termination points and splices, we will be able to reduce the failure rate of our underground cables resulting in fewer outages for our customers.

Q. HAVE OTHER UTILITIES HAD SUCCESS WITH SIMILAR CABLE LIFE EXTENSION PROGRAMS?

A. Yes, CenterPoint Energy that implemented a similar program in Texas in 2013 and has seen their underground failure rates reduced by 98 percent. CenterPoint Energy used this technology to assess over 16,000 segments of cable that were 35 or more years old. Of the underground cable loops assessed thus far, 99.6 percent have required on-site mitigation or span replacement to return the cables and terminations to manufacturer specifications, or like-new performance condition. However, the cost to assess and restore an underground loop to like-new performance has been about 65 percent less than the cost to completely replace it.

Another utility with a similar underground cable failure rate assessed over 2,000 miles of cable and found 82 percent of cable did not require further action. As a result, they were able to reduce replacement costs by 76 percent and associated cable outages by 98 percent.

These two utilities had two different results based on the assessment provided by this technology. One learned that they needed to rehabilitate a large portion of their underground system while another learned that their system was mostly intact and they could focus their efforts elsewhere. Both of these results provided value for these utilities either in terms of reduced rehabilitation costs or the ability to turn attention to other critical needs on their system. At this time, Xcel Energy does not have a holistic assessment of the current condition of our underground cables. As a result, we do not know which of these categories we will fall into.

Q. WHAT WORK WILL BE PERFORMED IN 2021 AND 2022?

A. The Company plans to perform up to 60 miles of cable assessment and rehabilitation in 2021 and 2022.

(c) Network Monitoring

Q. PLEASE DESCRIBE THE NETWORK MONITORING PROGRAM.

A. The Network Monitoring program will enable remote monitoring of the network grids for downtown Minneapolis and St. Paul to ensure continuity of service, health of these assets, and will improve operation and maintenance. 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;
- monitor the system on a real-time basis;
- more accurately document system performance;
- customize breaker parameters;
- reduce O&M expenses related to troubleshooting and identifying faulty network equipment; and
- Provide more granular individual transformer loading and planning data.

Q. ARE THERE ANY OTHER BENEFITS OF THE NETWORK MONITORING PROGRAM?

A. Yes. Additional benefits we expect from this program include improved employee and public safety, security, reliability, planning, and control.

Q. HOW WILL SAFETY BE IMPROVED?

A. Safety will be improved by enabling remote operation of the network circuits and by notifying personnel of potential dangers before entering a confined space in the underground distribution system. For instance, Company personnel will be notified that equipment has failed, is failing and/or operating abnormally, and can avoid entering the enclosed vault until the equipment has been de-energized or evaluated remotely.

Q. HOW WILL RELIABILITY, PLANNING, AND CONTROL BE IMPROVED?

A. Reliability will be improved by monitoring the status of and being able to remotely control the Network Protectors. Planning will be improved by having load (kW and Amps) data available for each individual network transformer, improving and optimizing the ability to serve changing or new customer loads at specific locations. Control will be improved because the project will enable the Company to use the additional network information to make more educated decisions regarding system design and operations. In addition, understanding that equipment is not operating as designed will enable the Company to make the necessary repairs or replacement avoiding lengthy outages to customers in our central business districts.

Q. HOW DOES THE COMPANY KNOW THAT THE NETWORK MONITORING PROJECT WILL PROVIDE THESE BENEFITS?

A. Our Colorado operating company affiliate, Public Service Company of Colorado (PSCo), implemented a similar monitoring system in the Denver Underground Network around 2010 and has experienced the benefits listed above.

Q. HOW DID THE NETWORK MONITORING IMPLEMENTED BY PSCO IMPROVE RELIABILITY FOR THE DENVER DISTRIBUTION SYSTEM?

A. Prior to the implementation of network monitoring, when PSCo's system operators were notified of a system interruption, a crew would have to be dispatched to the general area to investigate. They would begin the trouble shooting process by starting at the head end of the feeder line, and then physically enter every single vault on that feeder to inspect the equipment and determine if the cause could be found. If no immediate cause was detected, the crew would reset all equipment and attempt to energize the feeder again. If another interruption of service was detected, the crew would be forced to further begin isolation activities to narrow the root cause. This process could take hours or days and may leave the network system vulnerable to outage and other service issues.

With the implementation of network monitoring, the PSCo system operators are notified immediately of a detected interruption by the monitoring system. A crew can then be dispatched to the specific vault where the issue was detected for further testing and repair or replacement of any assets as needed. By reducing notification time for a fault and receiving data that considerably narrows down the location of the potentially faulty equipment, system faults can be identified and repaired much faster.

Q. HOW DID PSCO'S NETWORK MONITORING IMPROVE SAFETY?

A. Allowing remote control of network equipment allows personnel to immediately respond to major faults from a safe location, which can help prevent catastrophic failure and system interruption.

As an example, during a 2016 event in Denver, an email was sent to the PSCO system operators notifying them of a high-temperature alarm. The affected network equipment was located in an alley that had been filled with water due to a heavy rain storm. The resistors in the equipment began to boil the water inside the network protector. After receiving the alarm notification, the breaker was opened remotely by the PSCO system operator. The crew was then dispatched to dry out the equipment and prevent catastrophic failure and system interruption. The monitoring equipment kept PSCO personnel and the public safe by providing immediate notice of a serious issue and allowing the system operator to remotely open the breaker prior to sending out a crew to the scene.

Q. WHAT WORK WILL BE PERFORMED IN 2022 FOR THE NETWORK MONITORING PROJECT?

A. We plan to have one network in service with live monitoring in 2022.

(d) St. Paul Tunnel Rehabilitation

Q. WHAT IS THE ST. PAUL TUNNEL REHABILITATION PROJECT?

A. This project will improve the safety and security of our underground distribution facilities in St. Paul by eliminating the risk of system outages to downtown St. Paul if the tunnels were to collapse.

The electric distribution and network infrastructure in and around downtown St. Paul is housed underground in a sandstone tunnel system that was built in the late 1800s. There are approximately 10 miles of tunnels, and they vary in width and depth. The tunnels are made in sandstone and are eroding internally, causing a build-up of sand and debris within the tunnels; flooding can then cause complete blockage of the tunnels based on the washed-out debris. The placement of utility infrastructure in them is problematic and poses a potential hazard for our employees. Further, the tunnels are shared with other utilities, which can impact the safety and reliability of our system based on failure of the assets not owned or maintained by our Company, which may cause residual impacts to our electrical assets.

Under this program, we would build new infrastructure to retire and replace the existing tunnel system. This will include constructing new underground manhole and duct infrastructure, in accordance with current Company standards, city requirements – and in consideration of safe practices for our employees. Existing electrical facilities would be relocated from the old tunnel system and into the new duct system as it is constructed. We additionally have concerns regarding the access and security of these tunnels.

Q. WHAT ARE THE OTHER ISSUES ASSOCIATED WITH HAVING DISTRIBUTION FACILITIES LOCATED IN THE ST. PAUL TUNNELS?

A. Assess is an issue. Accessing the tunnels is done in a variety of ways, including doorways built into bluffs and manhole access from street grade. Our employees, when entering the tunnels from a street-level manhole, use long ladders to climb down to the grade in which our electrical assets are housed, as many tunnels are 30'-50' below street grade. They are then working out of cell phone range, and may face issues with communication, particularly in an emergency situation.

Q. WHEN WILL THIS PROJECT BE COMPLETED?

A. The length, condition, and location of the tunnels presents unique construction challenges, that will require extensive city, community and customer coordination, detailed planning and engineering, and system operations considerations to ensure service is maintained to all customers currently served by these parts of our electrical system. We expect, given these challenges and required coordination, this project may take up to 15 years to complete. We expect however that the first assets will be placed in service in 2021 and 2022. These first assets will include the first conduit vaults and duct vaults that will be required to move our electrical equipment out of the tunnels.

(e) Feeder Exit Capacity

Q. WHAT IS THE FEEDER EXIT CAPACITY PROJECT?

A. The purpose of the Feeder Exit Capacity project is to identify areas of the distribution system in which the overall load carrying capacity feeder circuits are limited by undersized cables, conductors, or other equipment at the feeder's head end. The project will benefit customers by improving the existing distribution system's ability to accommodate new load growth. Increasing the capacity of the feeders will also reduce the overall loading on the feeder circuits, which in some cases can prevent premature equipment failure, therefore improving reliability.

The overall load carrying capacity of a feeder circuit is determined as the minimum series element's capacity rating on the feeder circuit between the feeder bay in the substation and the first customers served by the feeder – this portion of the feeder is typically referred to as the feeder's exit, or head end. This project will allocate funds towards feeders where these reduced capacity ratings can be readily increased by upgrading the feeder equipment as necessary along the feeder's exit from the substation.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE FEEDER EXIT CAPACITY PROJECT?

A. The Company will in-service up to eight feeder exits in 2021 and 2022.

(f) Purchases and Tools

Q. WHAT IS INCLUDED IN THE PURCHASES AND TOOLS CATEGORY?

A. To support additional work volume and scope with internal resources, it is necessary and to purchase additional equipment and tools. The purchases will include Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR PURCHASES AND TOOLS?

A. These purchases will amount to $4.5 million in 2021 and up to $200,000 in 2022.

(3) Substation Programs

Q. DESCRIBE THE SUBSTATION PROGRAMS THAT ARE PART OF THE ISI INITIATIVE?

A. There are two substation programs that will improve the reliability and resiliency of the Company's 224 substations in Minnesota. These two programs are: (1) substation transformer replacement; (2) substation asset renewal. The capital additions for each of these programs are provided in Table 14.

Table 14

ISI Capital Additions – Distribution State of MN Electric Jurisdiction (Dollars in Millions)				
		2020	2021	2022
Substation Programs	Transformer Replacement		$5.0	$14
	Substation Asset Renewal		$5.0	$14
	TOTAL		**$5.0**	**$21.5**

(a) Substation Transformer Replacement Program

Q. WHAT IS THE SUBSTATION TRANSFORMER REPLACEMENT PROGRAM?

A. Substation transformers are a 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 and results in between 5,000 to 15,000 customers losing service. This program will increase the rate at which the Company replaces its substation transformers from approximately three per year to approximately eight per year.

Q. WHY IS IT NECESSARY TO INCREASE THE RATE OF SUBSTATION TRANSFORMER REPLACEMENTS IN MINNESOTA?

A. The Company's current limited replacement of three transformers per year includes transformers that have been identified as needing replacement due to their age and condition, and transformers that have failed. The current average replacement life cycle is 60 years. Assuming the Company replaces five additional transformers each year, we will reduce the replacement life cycle of our existing transformers to 57 years.

Q. WHAT WORK WILL BE PERFORMED DURING 2021 AND 2022 FOR THIS PROGRAM?

A. Under this program, we will replace up to four additional substation transformers in 2021 and approximately 10 additional substation transformers in 2022.

(b) Substation Asset Renewal

Q. WHAT IS THE SUBSTATION ASSET RENEWAL PROGRAM?

A. Historically, we have separately replaced the individual parts within the substation as they fail or reach of the end of life. These individual parts include breakers, relays, and Remote Terminal Unit (RTUs)/Local Control Unit (LCUs). Rather than replacing individual components on a piecemeal basis, the Substation Asset Renewal program would replace the bulk of the equipment within a substation at one time. We select and prioritize the substations using several factors, including: age and condition of equipment, amount and type of load served, system reliability and future growth and planning.

Q. WHAT ARE THE BENEFITS TO CUSTOMERS OF THE SUBSTATION RENEWAL PROGRAM?

A. Similar to substation transformers, replacing these key components of the substation will improve the reliability of our substations. In addition, by upgrading this equipment, the new equipment will have additional functionality that will allow for improved communication and monitoring of the substation equipment.

Q. WHAT WORK WILL BE PERFORMED DURING 2022 FOR THIS PROGRAM?

A. We plan to replace up to 32 breakers, 42 relays, and 5 RTU/LCUs at multiple substation locations across Minnesota during 2022.

(4) Overhead Mainline Programs

Q. DESCRIBE THE OVERHEAD MAINLINE PROGRAM PORTION OF THE ISI INITIATIVE?

A. This program targets overhead mainline feeders which are the larger capacity feeders found along major roadways that then branch off into smaller overhead tap lines and then to service laterals that connect to homes and businesses. There are two components of this program: (1) pole fire mitigation; and (2) lightening arrestor replacement.

Table 15

ISI Capital Additions – Distribution State of MN Electric Jurisdiction (Dollars in Millions)				
		2020	2021	2022
Overhead Mainline Programs	Pole Fire Mitigation		$2.0	$2.5
	Lightning Protection Replacement		$0.8	$1.0
TOTAL			**$2.8**	**$3.5**

(a) Pole Fire Mitigation Program

Q. DESCRIBE THE POLE FIRE MITIGATION PROGRAM.

A. This program seeks to reduce the risk of pole fires by identifying poles that are risk for fire and then replacing certain components (enhanced insulation, replacing wooden cross-arms with fiberglass) or when necessary, replacing the pole or relocating the line away from airborne contaminants.

Pole fires can be a significant cause of service interruptions. We average more than 14 mainline pole fires a year; each mainline pole fire impacts more than 1,500 customers when the outage occurs. We are typically able to restore power to most of the customers through field switching. However a smaller number of customers are usually without power until the pole can be replaced, which can be as long as 12 hours. The Company currently has 2,600 mainline poles (of the approximately 500,000 total poles, or 0.52 percent) deemed to be at risk of fire in Minnesota. By strategically addressing these at-risk poles, customers will experience fewer power interruptions.

Poles that are at risk are typically found on busy streets with high usage of chemicals used for de-icing of rights-of-way and are typically are older poles and have a higher than average number of components located on the pole. Under this program, the Company will spend approximately $2.5 million per year to identify at-risk poles and replace the necessary components.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE POLE FIRE MITIGATION?

A. The Company plans to replace up to 500 poles in 2021 and 2022.

(b) Lighting Arrestor Replacement Program

Q. DESCRIBE THE LIGHTING ARRESTOR REPLACEMENT PROGRAM.

A. A lightning arrestor is a device on a distribution pole that protects the conductors and insulators from damage due to lightning. Outage due to arrester failure is one of the main causes of outages on the overhead system. It is estimated over 90 percent of the SAIDI impact from lightning arrestor failure is attributable to a few vintage models, that make up fewer than 30 percent of the arrestors. By replacing these lightning arrestors that are at risk, we anticipate that customers will experience improved reliability.

This program identifies lightning arrestors with high failure rates and replaces these arrestors to ensure that this equipment operates properly in the event of a lightning strike. Under this program, we will spend approximately $200,000 per year to identify and replace lightning arrestors at risk of failure.

Q. WHAT ASSETS WILL BE PLACED IN-SERVICE IN 2021 AND 2022 FOR THE LIGHTING ARRESTOR REPLACEMENT PROGRAM?

A. The Company plans to replace up to 1,000 lighting arrestors in 2021 and 2022.

b. Other Non-Routine Asset Health and Reliability Projects

Q. WHAT ARE THE KEY NON-ROUTINE ASSET HEALTH PROJECTS WILL DISTRIBUTION UNDERTAKE DURING 2020 TO 2022?

A. In addition to the ISI Initiative, there are two other key non-routine Asset Health and Reliability projects that the Company will undertake during these years: (1) replacement of the 5th Street Switchgear; and (2) rebuild of the West St. Cloud to Millwood distribution line.

Q. DESCRIBE THE FIFTH STREET SUBSTATION SWITCHGEAR REPLACEMENT PROJECT?

A. The Fifth Street Substation Switchgear Replacement Project is a four-year project that began in 2017. This project involves replacing all of the original switchgear at our Fifth Street Substation in Minneapolis that serves the majority of the downtown load. The existing switchgear is over 50 years old and has exceeded its useful life. Due to its age, it has also become increasingly difficult to maintain this equipment as newer replacement parts are not compatible with the over 50 year old equipment. In addition, the new switchgear will have new arc-resistant safety features which will redirect any abnormal arcing that may occur away from where it could interact with employees. This new switchgear will also have the ability to add more capacity as needed to accommodate additional load in downtown Minneapolis. Our work in 2020 involves replacing the remaining two switchgear enclosures. Two of the three phases of the project have been completed and are in service. The final phase will be completed in the fourth quarter of 2020. All three phases of the project will total to a Minnesota jurisdiction plant addition of $8.6 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. The West St. Cloud to Millwood Rebuild project is planned to be in service by the fourth quarter 2022 with a Minnesota jurisdiction plant addition of $5.4 million.

c. Routine Asset Health and Reliability Projects

Q. WHAT ARE ROUTINE ASSET HEALTH AND RELIABILITY PROJECTS?

A. 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.

Q. CAN THE ROUTINE ASSET HEALTH AND RELIABILITY PROJECTS BE BROKEN DOWN INTO FURTHER GROUPINGS?

A. Yes. Tables 16 and 17 provide a further breakdown of the capital projects in the Asset Health and Reliability category.

Table 16

Routine Asset Health and Reliability Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2016	2017	2018	2019	2020	2021	2022
Asset Health and Reliability							
Routine Rebuilds, Conversions & Programs	$23.6	$35.9	$31.6	$35.5	$30.9	$40.2	$40.2
Routine Cable Replacement	$15.8	$15.2	$23.3	$19.7	$20.0	$30.5	$26.5
Routine Restoration/Failure Reserves	$21.6	$17.0	$11.0	$12.7	$9.7	$13.2	$13.9
Routine Pole Replacements	$1.7	$0.3	$8.6	$13.1	$25.4	$16.6	$15.7
Total	**$62.7**	**$68.4**	**$74.5**	**$81.0**	**$86.1**	**$100.5**	**$96.3**

Table 17

Routine Asset Health and Reliability Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Expenditures (excludes AFUDC)	2016	2017	2018	2019	2020	2021	2022
Asset Health and Reliability							
Routine Rebuilds, Conversions & Programs	$21.3	$27.1	$35.8	$36.8	$35.1	$45.0	$45.1
Routine Cable Replacement	$19.2	$21.4	$21.5	$18.0	$20.4	$31.1	$27.0
Routine Restoration/Failure Reserves	$24.2	$18.1	$14.8	$10.4	$15.5	$14.9	$15.5
Routine Pole Replacements	$6.7	$7.3	$9.8	$16.2	$28.9	$17.7	$17.7
Total	**$71.2**	**$73.8**	**$81.9**	**$81.5**	**$99.8**	**$108.7**	**$105.2**

Q. TABLE 16 SHOWS INCREASING CAPITAL ADDITIONS IN THE ROUTINE REBUILDS, CONVERSIONS AND PROGRAMS CATEGORY BETWEEN 2020 AND 2022. WHAT IS DRIVING THIS INCREASE?

A. In general, during this period we will be increasing our investments in the Routine Rebuilds and Conversions category as a portion of this program was deferred in 2020 to allow for capital investments in other Business areas. We are increasing our funding to proactively replace aging and damaged poles and cables.

Q. WHAT IS INCLUDED IN THE ROUTINE REBUILDS, CONVERSIONS, AND PROGRAM CATEGORY LISTED IN TABLE 16?

A. The bulk of this category is for small projects of a routine nature including replacing poles due to public damage, or for undergrounding overhead lines, generally at the request of customers or government entities (portions may be compensable). Also included in this category is the mixed work adjustment that is an adjustment to our capital additions to properly allocate the split between capital and O&M for certain routine work orders in two areas: (1) routine pole replacements and (2) Engineering and Supervision (E&S).

Q. HOW DID THE COMPANY DETERMINE THE MIXED WORK ADJUSTMENT AMOUNT FOR 2020 TO 2022?

A. 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, etc.). 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. To determine the mixed work adjustment amount for pole replacements for 2020 to 2022, we used the forecasted volume of pole replacements for each year and calculated the forecasted capital and O&M expenditures that would result each year from the original capital/O&M split and then also from the new capital/O&M split. Our average per pole replacement unit cost was utilized with the forecasted units for each year to derive the amount of capital/O&M expenditures from each of the two financial split scenarios. We then calculated the difference in capitalization amounts between the two scenarios and applied this as the mixed work adjustment needed for each year.

E&S work is back-office work performed by our employees to support our routine work orders. To determine the proper allocation, we review this work at least every two years to ensure these capital versus O&M splits are kept current with the type and mix of work being supported by our back-office. This review entails an "activity" survey sent to each manager whose department is eligible for E&S charging to get their latest assessment on how much time they typically spent per month on activities that directly support capital work vs. O&M work and/or other non-capital type administrative activities (e.g. training, administrative meetings, etc.). These surveys are then collected by our Finance area and combined into an overall E&S analysis for the Distribution Organization. Based on the most recent review in 2019, we determined that a greater portion of E&S work needed to be allocated to capital with an equivalent reduction in E&S O&M. On the capital side, this will show up as a net increase in the E&S allocations across all Distribution Line capital projects. For O&M, it will manifest itself in a decrease to the cost elements of "Labor and Outside Services." To determine the mixed work adjustment amount for E&S for 2020 to 2022, we took the total expected E&S costs on an annual basis (using most recent history) and adjusted dollars between capital and O&M based on the net change in the new E&S capital splits vs. the O&M splits. The mixed work adjustment amounts for pole replacement and E&S were combined to form the total Minnesota jurisdiction plant addition of $8.0 million in 2020 and $10.5 million in both 2021 and 2022.

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

A. The budget for this category is based primarily on historical experience, with additional consideration given to economic conditions which tend to influence these customer requests.

Q. WHAT IS INCLUDED IN THE ROUTINE CABLE REPLACEMENT CATEGORY LISTED IN TABLE 16?

A. The NSPM distribution system has nearly 1,500 miles of underground feeder cable and over 9,100 miles of underground tap cable. The Renewal-Cable category refers to replacement of portions of this underground cable. The purpose of these investments is to improve reliability and system performance. The specific sections of cable selected for replacement are chosen based on reliability data, and in some cases, selections are influenced by historical performance of the types and vintages of cable.

Q. HOW WAS THE BUDGET FOR ROUTINE CABLE REPLACEMENT DEVELOPED?

A. The budget for this category is developed based upon historical trends of failure/fault rates and reliability needs. The work occurs throughout the year, with the greatest portion of the work taking place during months without frost to minimize expense.

Q. WHAT ARE THE DRIVERS OF THE INCREASE TO ROUTINE CABLE REPLACEMENT CAPITAL ADDITIONS IN 2021 AND 2022?

A. Our investments in this area are increasing in 2021 and 2022 based on a renewed focus on addressing aging cable on our system.

Q. WHAT IS INCLUDED IN THE ROUTINE RESTORATION/FAILURE RESERVES CATEGORY?

A. This category includes investments required to repair facilities that are damaged during storm events as well as to address failed substation equipment.

Q. HOW WAS THE BUDGET FOR ROUTINE RESTORATION/FAILURE RESERVES DEVELOPED?

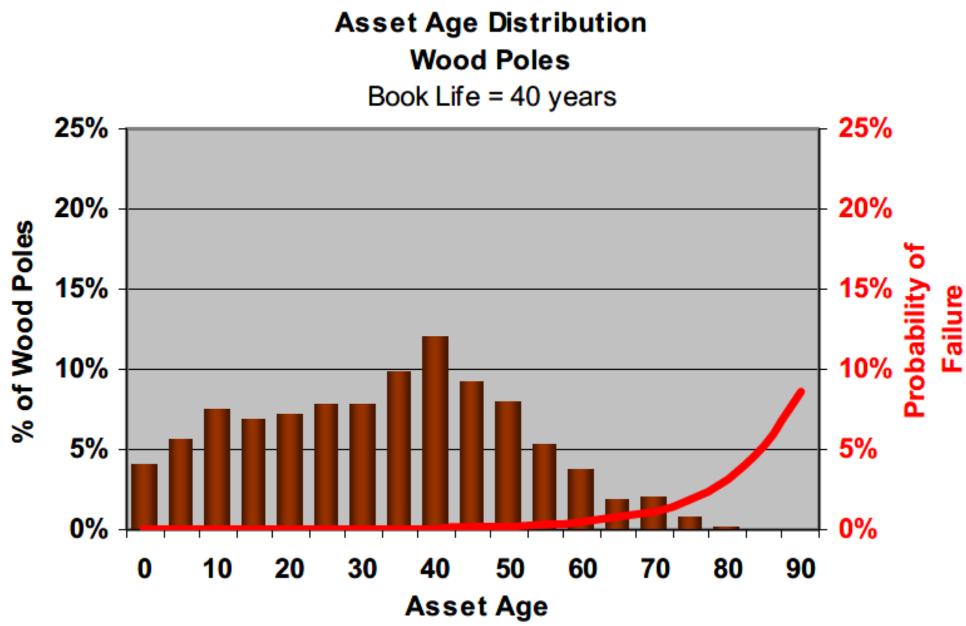
A. This budget is developed based on historical trends and investments in this category are relatively steady throughout 2020 to 2022.

Q. WHAT IS INCLUDED IN THE ROUTINE POLE REPLACEMENT CATEGORY LISTED IN TABLES 16 AND 17?

A. This refers to pole replacements. Similar to cable replacements, we replace poles that have reached end of life, as determined by ground pole testing. The NSPM distribution system has approximately 525,000 wooden poles in service, and these poles have a service life, on average, of 44 years. Pole rot at the base of the pole can be a cause of pole failure, especially during storms. As shown in Figure 7 below, those poles at the end of their service life of 44 years have the highest rate of failure. I note that the lower rate of failure for poles older than 40 years is because we simply do not have many of these poles on our system as they are typically replaced earlier in their life cycle.

Figure 7

Pole Failure Risk by Age of Pole



Q. HOW WAS THE BUDGET FOR ROUTINE POLE REPLACEMENT DEVELOPED?

A. We work to inspect poles on a 12-year cycle to mitigate risk of pole failures and we budget to test approximately 8.3 percent of our pole plant each year. Actual poles inspected each year can vary depending on overall budget management efforts and the actual poles replaced depends on the rejection rate of the inspected poles. Costs are estimated on a per-pole basis, using historical data and any known anticipated changes in labor and material costs. The work takes place throughout the entire year.

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. Specifically, 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. Our investments in street lights are expected to remain flat during 2020 to 2022 as our LED street light conversion project will be completed in 2019.

Table 18 provides a breakdown of the components that comprise the New Business category of capital additions.

Table 18

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2016	2017	2018	2019	2020	2021	2022
New Business							
Extensions/Services	$20.1	$26.4	$30.4	$23.7	$29.3	$32.9	$33.4
Meter Purchases	$5.1	$5.7	$5.3	$6.1	$5.1	$4.0	$3.2
Street Lighting	$5.8	$8.2	$1.8	$8.5	$2.1	$2.1	$2.1
Transformer Purchases	$20.1	$15.8	$26.0	$17.9	$21.4	$22.9	$21.9
Total	**$51.2**	**$56.2**	**$63.5**	**$56.1**	**$57.9**	**$62.0**	**$60.7**

Q. HOW DO YOU DEVELOP A BUDGET FOR NEW BUSINESS INVESTMENTS?

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 new housing starts and modified by known trends in service territories. Due to the strong economy, we expect continued steady investments in the New Business category as new housing starts are expected to continue to remain high through 2022 thus requiring continued new extensions and meter and transformer purchases. The Company predicts a similar trend for meter growth, modified slightly based upon historical trends and knowledge of specific service territories.

Q. WHAT ARE THE MAJOR COST DRIVERS FOR 2020 TO 2022 IN THE NEW BUSINESS CATEGORY?

A. We expect our investments in New Business to remain relatively steady from 2020 to 2022. However, I note that economic conditions can impact our new business investments and an economic downturn can reduce these anticipated investments, while greater than anticipate economic growth or extensions to large load customers can increase anticipated New Business capital additions.

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.

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

A. 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. The resulting budget seeks to most effectively invest the resources both within the Capacity category and across the other categories as well. Table 19 provides a summary of the capital additions budget for 2020 to 2022 for Capacity projects.

Table 19
2020-2022 Capital Additions – Capacity
(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2020	2021	2022
Capacity	$30.8	$54.1	$38.2

Q. WHAT IS DRIVING THE INCREASE IN CAPITAL ADDITIONS FOR CAPACITY PROJECTS IN 2021?

A. This increase is driven by several large capacity projects are planned to be placed in-service in 2021. These projects include the Wilson Substation project and the Hollydale Substation project. I will describe these projects in further detail below.

Q. WHAT OTHER KEY CAPACITY PROJECTS ARE PLANNED IN 2020 TO 2022?

A. In addition to the Wilson Substation and Hollydale Substation project, another key capacity project is the new South Washington Substation project that has a planned in service date in 2020.

Q. PLEASE DESCRIBE THE SOUTH WASHINGTON SUBSTATION PROJECT.

A. The South Washington Substation project involves the construction of a new substation in Woodbury, Minnesota. Due to residential and commercial growth in the Woodbury area, more distribution capacity is needed to reliably serve existing and future customers. We will be installing one 115 kV – 34.5 kV 70 MVA transformer at this new substation as well as two 34.5 kV feeders.

The South Washington substation is needed to address existing contingency risks that could occur if certain distribution elements are out of service during peak demand. Construction of the two new feeders is necessary to address a forecasted overload on an area feeder in 2020 and to resolve the existing substation contingency. The South Washington Substation project will also provide additional capacity to accommodate future load growth in this area. This substation is planned to be in service in the fourth quarter of 2020 with a Minnesota jurisdiction plant addition of $7 million.

Q. PLEASE DESCRIBE THE HOLLYDALE SUBSTATION PROJECT.

A. The Hollydale Substation project involves expanding the existing Hollydale Substation in Plymouth, Minnesota and installing two new 69-34.5 kV transformers. This project also involves the construction of three new 13.8 kV feeders and other feeder reconfigurations in the area. This project is the result of a joint transmission and distribution engineering study of the area that was finalized in 2016. The project will improve the reliability of the distribution system in the area surrounding the Hollydale substation. It will also ensure the ability of the distribution system to accommodate new load growth in the area by mitigating existing capacity deficiencies and providing needed long-term capacity. The project is slated to be in service in November 2021 with a Minnesota jurisdiction plant addition of $18.7 million.

Q. PLEASE DESCRIBE THE WILSON SUBSTATION PROJECT?

A. The Wilson Substation project involves the installation of a fourth transformer, construction of three new distribution feeders, new manholes, and a new duct line. Substation and transmission equipment within the Wilson substation will also be upgraded as a part of the project. The Wilson

Substation is an existing substation located in Bloomington, Minnesota. This project is needed to mitigate multiple overloads and risks in the area that have resulted from the steady load growth in this area. Resolving these issues ensures that we can continue to provide reliable service to our customers as this area continues to grow. The Wilson Substation project is slated to be in service in October 2021 with a Minnesota jurisdiction plant addition of $17.9 million.

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.

Q. HOW DO YOU 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 large service territories including Minneapolis and St. Paul 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.

Table 20 provides a summary of the capital additions budget for 2020 to 2022 for Mandate projects.

Table 20

2020-2022 Capital Additions – Mandates

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2020	2021	2022
Mandates	$17.8	$27.6	$39.6

Q. WHAT IS DRIVING THE INCREASE IN CAPITAL ADDITIONS FOR MANDATE PROJECTS IN 2021 AND 2022 AS COMPARED TO 2020?

A. In both 2021 and 2022, there are two large mandate projects that are required due to road construction projects in the City of Minneapolis—the Fourth Street project in 2021 and the Hennepin Avenue project in 2022.

Q. PLEASE DESCRIBE THE FOURTH STREET PROJECT.

A. The City of Minneapolis is reconstructing a 0.6 mile segment of Fourth Street between 2nd Avenue and 4th Avenue South. 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. Vaults provide protection and access to our underground network and during road construction projects, the street and sidewalks elevation change requiring us to rebuild the vault top. The Fourth Street project will be in service in June 2021 with a Minnesota jurisdiction plant addition of $8.2 million.

Q. PLEASE DESCRIBE THE HENNEPIN AVENUE PROJECT.

A. The City of Minneapolis is reconstructing and realigning a 10 block stretch of Hennepin Avenue between Washington Avenue and 12th Avenue. 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 redesign of Hennepin Avenue as well as vault top restoration and feeder extensions for tying into existing system where necessary. The Hennepin Avenue project will be in service in March 2022 with a Minnesota jurisdiction plant addition of $12.2 million.

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.

Q. HOW DO YOU ESTABLISH THE BUDGET FOR TOOLS AND EQUIPMENT?

A. One of the largest drivers in this category over the three year term of this case is equipment purchases necessary for Feeder Load Monitoring which add equipment to feeders to allow the Company to monitor peak demand on each feeder. Another driver for 2020 is Advanced Planning Tool (APT). Table 21 provides a summary of the capital additions budget for 2020 to 2022 for Tools and Equipment.

Table 21

2020-2022 Capital Additions - Tools and Equipment

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2020	2021	2022
Tools and Equipment	$6.9	$3.7	$4.2

Q. DESCRIBE THE ADVANCED PLANNING TOOL.

A. The Advanced Planning Tool (APT) is a spatial load forecasting tool, which combines several layers of detailed electric infrastructure, weather, economic and other data to forecast how future load and energy demands on the grid may change in the future. APT is a foundational planning tool that will enhance system reliability as well as supporting modernization of our distribution system. APT will replace our current planning tool that lacks the ability to provide the data granularity and transparency necessary to keep pace with customer expectations and evolving regulatory requirements. For example, the current planning tool can only provide forecast information at the feeder and substation level and lacks the ability to measure two-way power flows that is needed to allow us to understand the grid impacts of varying levels of DER adoption. The APT is expected to be in service by the third quarter 2020 with a Minnesota jurisdiction plant addition of $4 million.

Q. IS THE COMPANY SEEKING COST RECOVERY FOR APT IN THIS RATE CASE?

A. The costs for the APT are currently included in this rate case. However, the Company is requesting certification of APT in our annual IDP, which is being filed concurrently with this rate case. Additional details about APT and its benefits for our customers are provided in the IDP. If APT is certified by the Commission, the Company plans to request recovery of its costs in a subsequent TCR Rider filing and will provide an adjustment to the rate case budgets in Rebuttal Testimony.

Q. ARE YOU EXPECTING A SIGNIFICANT CHANGE IN THE AMOUNT OF INVESTMENTS IN THIS BUDGET CATEGORY FROM 2020 TO 2022?

A. No. As shown in Table 21, we anticipate that our investments in this area will remain relatively steady through these years with a slight increase in 2020 due primarily to APT.

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. While the level of capital investments that Distribution seeks to recover in this rate case are higher than historic 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.

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 labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention. Finally, it includes miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system and fleet (vehicles, trucks, trailers, etc.). Specifically, the O&M component of fleet are those expenditures necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet support 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 OVERALL TRENDS FOR DISTRIBUTION'S O&M EXPENSES?

A. Distribution's O&M expenditures have been steadily increasing from 2016 to 2018 due to increased expenses to cover an increased volume of pole replacements, training related to the new Work and Asset Management (WAM), mutual aid provided to other utilities following storms and hurricanes. I note that while the Company is reimbursed for its expenses incurred in providing this mutual aid these reimbursement are taken back into the Company as revenue and therefore do not get credited back to Distribution's O&M budgets. Beginning in 2019, our O&M expenses will experience more marked growth as a result of Distribution's key role in implementing several new capital programs, namely the AGIS initiative as well as the ISI Initiative.

Q. WHAT IS THE COMPANY'S DISTRIBUTION O&M BUDGET FOR 2020 TO 2022?

A. As shown in Table 22, we have budgeted $116.6 million for Distribution O&M in 2020, $124.7 million in 2021, and $124.0 million in 2022.

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

A. Distribution's O&M budget can be broken into six categories: 1) Internal Labor, (2) Contract Labor, (3) Fleet, (4) Materials, and (5) Other.

Exhibit___(KAB-1), Schedule 3 provides a summary of O&M costs. Table 22 provides a historic look at actual O&M expenditures from 2016 to 2018, as well as forecast O&M expenditures for 2019 (half year actuals and half year forecast), and budgeted expenditures for 2020 to 2022 by category. The basis for this budget is set forth in detail below, utilizing the same categories of O&M utilized in our most recent rate case.

Table 22

NSPM Electric	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget	2021 Budget	2022 Budget
Internal Labor	46.8	48.1	51.9	53.8	58.3	59.8	60.5
Contract Labor	42.9	46.2	49.5	55.0	48.4	54.9	53.5
Fleet	7.3	8.3	8.3	7.4	6.9	6.8	6.8
Materials	8.5	8.1	7.0	5.9	6.9	6.8	6.8
Other	-1.6	-2.4	0.1	-0.2	-3.9	-3.6	-3.6
Total[4]	**104.0**	**108.3**	**116.8**	**121.9**	**116.6**	**124.7**	**124.0**

Q. WHAT WERE THE DRIVERS BEHIND THE INCREASED O&M EXPENSES BETWEEN 2016 AND 2018?

A. Between 2016 and 2017, Distribution's O&M expenses increased slightly due to the need to increase spending to cover a higher volume of programmatic pole replacements and due to increased work for vegetation management to enable Distribution maintain a five-year trim cycle for our facilities. Between 2017 and 2018, our 2018 actual O&M expenditures increased by $8.5 million, or 7.8 percent, over 2017 actuals. This increase was primarily due to $4.5

[4] Includes O&M associated with the Company's ADMS deployment which we are seeking recovery of in the TCR rider.

million for Puerto Rico mutual aid. This mutual aid 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. In addition, in 2018 we increased Internal Labor by $0.7 million as new employees were hired to fill key vacancies after Distribution exceeded our attrition goals due to greater than anticipated retirements and voluntary departures. Further, O&M in 2018 increased due to $2.1 million in contracted and base pay increases to labor rates and non-labor inflationary factors (Labor/Non-Labor escalation). Finally, $0.8 million of incremental training was required in 2018 due to the implementation of our new WAM accounting system.

Q. WHAT ARE THE DRIVERS BEHIND THE INCREASE IN O&M EXPENSES BETWEEN 2018 ACTUALS AND THE 2019 FORECAST?

A. The 2019 O&M forecast of $121.9 million is $9.6 million more than 2018 actuals (normalized to remove $4.5 million in Puerto Rico mutual aid from 2018). This increase is primarily driven by:

- *Labor/Non-Labor Escalation*: $2.0 million of Labor/Non-Labor escalation – this includes expected and contracted for annual increases in labor rates, as well as inflationary increases in non-labor costs, such as service provider contract rates, materials, and other non-labor items;
- *Storm Response*: $1.6 million of incremental and unexpected weather and storm response over 2018 levels – based on an active storm season during the first part of 2019 and continuing into the third quarter. The weather and storm response activity is forecasted to be 110 percent higher than an average storm year;
- *First Set Credits*: Approximately $2.0 million in lower transformer and meter "first set credits" – first set credits were lower in 2019 primarily

due to the Company having to order additional transformers in 2018 due to a delivery timing issue with one of our suppliers;

- *Solar Gardens*: $2.2 million in incremental 2019 solar garden engineering study costs over and above 2018 levels;
- *Line Clearances*: $2.0 million in additional distribution line-clearance forecasted expenditures in 2019 versus 2018 actuals.

Q. WHY IS THE 2020 BUDGET $5.3 MILLION LESS THAN THE 2019 FORECAST?

A. The primary drivers of the decrease in O&M from 2019 forecast to the 2020 budget are:

- *Storm Response*: $2.6 million reduction in weather and storm response expenses, assuming that storm activity returns to average in 2020;
- *First Set Credits*: $1.0 million of incremental transformer and meter first set credits versus the 2019 forecast, which, as discussed above was below budget due to a timing issue;
- *Centralized Scheduling*: $1.0 million in budgeted productivity improvement reductions that are expected to arise from updates to our centralized scheduling, which I describe later in my testimony; and
- *Mixed Work*: $4.4 million in "mixed work" O&M adjustments that I described earlier in the capital section of my testimony.

These decreases in O&M expenses are partially offset by $2.1 million in Labor/Non-Labor escalation.

Q. HOW ARE DISTRIBUTION'S O&M EXPENSES FOR 2020 TO 2022 DISTRIBUTED AMONG THE SIX BUDGET CATEGORIES?

A. Approximately 92 percent of the 2020 to 2022 Distribution O&M budgets are related to employee and contract labor. The remaining 8 percent of the O&M

budget is comprised of fleet, materials, and other costs such as employee expenses, O&M tool purchases, miscellaneous credits, and energy use costs. I note that the Other category in Table 23 is a net negative due to the fact that the miscellaneous first set credits, which I discussed above, more than offset the miscellaneous remaining expenditure types that roll-up to the Other category.

Table 23

Distribution O&M Budget by Category

(Dollars in Millions) NSPM Electric

Cost Category	2020 Budget (Million)	2021 Budget (Million)	2022 Budget (Million)	Percent of Total Budgets
Internal Labor	$58.3	$59.8	$60.5	49%
Contract Labor	$48.4	$54.9	$53.5	43%
Fleet	$6.9	$6.8	$6.8	6%
Materials	$6.9	$6.8	$6.8	6%
Other	($3.9)	($3.6)	($3.6)	-4%
Total[5]	**$116.6**	**$124.7**	**$124.0**	**100%**

Q. WHY DOES THE COMPANY USE CONTRACT LABOR FOR NEARLY HALF OF ITS O&M LABOR NEEDS?

A. Of the approximately $52 million in the NSPM Distribution O&M contract labor budgeted in 2020 to 2022, approximately 85 percent comes from two functions: Vegetation Management and Damage Prevention. I will describe these functions in detail later in my testimony. Due to the specialized nature of these tasks (e.g., tree trimming, pole inspections, underground facility locating) and the seasonal nature of the workload, the Company has

[5] Includes O&M associated with the Company's ADMS deployment which we are seeking recovery of in the TCR rider.

determined that the use of contract labor is more cost effective and efficient than utilizing employees. With contractor labor, the Company is able to competitively bid out 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. This flexibility is important given the seasonal nature of this work. If the Company were to hire employees for these positions, we would have to find a way to deploy this workforce to other areas during the winter months when these tasks are not performed at the same volume as in the summer and/or as overall annual work volumes change due to the economy or other factors.

Q. WHAT ARE THE MAJOR COST DRIVERS OF THE 2020 TO 2022 DISTRIBUTION O&M BUDGET?

A. The primary driver of the Company's O&M cost increase is implementation of the AGIS initiative. I will discuss the AGIS initiative, including the associated O&M costs in Section V of my testimony. If the O&M costs for AGIS are excluded, Distribution's O&M budget for 2020 to 2022 continues to trend slightly upward, but under the cost of inflation. The 2022 budget excluding AGIS of $117.2 million is only a $3.4 million increase over the 2020 budget of $113.8 million (excluding AGIS). This represents an annual increase of 1.5 percent over the two-year period. This is a moderate increase in the O&M budget given that Distribution will also be beginning work on the new ISI Initiative in 2021, which will require additional O&M to support the program (approximately $1.5 million annually).

Q. WHY ARE O&M EXPENSES INCREASING FROM THE 2020 BUDGET TO THE 2021 BUDGET?

A. The primary drivers of the $8.1 million increase from 2020 ($116.6 million) to 2021 ($124.7 million) are: $1.7 million for AGIS, $2.1 million in Labor/Non-Labor escalation, $1.3 million for OSHA required Crane Recertification Training and miscellaneous other training requirements (starting new in 2019), $1.5 million in support of the ISI Initiative, and $1.6 million in miscellaneous other expected activity increases. These increases are partially offset by a reduction of $1.8 million for productivity related improvement.

Q. HOW IS DISTRIBUTION ABLE TO AVOID INCREASES IN O&M EXPENSES BETWEEN THE 2021 BUDGET AND 2022 BUDGET?

A. The 2022 budget is essentially flat with the 2021 budget because the typical Labor/Non-Labor escalations are almost entirely offset by an incremental $1.8 million in productivity related improvements that resulted in O&M expense reductions in the 2022 budget. An example of these productivity improvements is the previously mentioned centralized scheduling initiative. Once fully implemented this centralized scheduling initiative should 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, ensuring that projects are proactively planned, designed, and resourced well ahead of construction. This is projected to allow the Company to realize efficiency gains at both the design and construction phases of our work, thus reducing overall costs from 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 DO THE DISTRIBUTION O&M BUDGETS FOR 2020 TO 2022 COMPARE TO THE THREE YEAR HISTORIC AVERAGE FOR 2016 TO 2018?

A. As shown in Table 24 below, Distribution's O&M budget for 2020, 2021, and 2022 averages $121.8 million, while the 2016 to 2018 historical average was $109.7 million. This $12.1 million increase represents a 1.8 percent average annual increase through the entire period of 2016 to 2022. This increase is due to annual base salary increases as well as O&M related to the incremental programs of AGIS and ISI. Starting in 2019, O&M related to AGIS will increase Distribution's O&M by $1.6 million in 2020, $1.7 million in 2021, and $2.3 million in 2022. I discuss the O&M budget for AGIS in greater detail in Section V of my testimony.

Table 24

Distribution O&M Actuals and Budget Comparison

(Dollars in Millions)

2016 Actual	2017 Actual	2018 Actual	2016-2018 Average	2020 Budget	2021 Budget	2022 Budget	2020-2022 Average
$104.0	$108.3	$116.8	$109.7	$116.6	$124.7	$124.0	$121.8

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 all 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 that 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. DOES THE ALLOCATION OF DISTRIBUTION O&M FUNDS EVER NEED TO BE CHANGED DURING THE FINANCIAL YEAR?

A. Yes. Given that no year ever transpires exactly as predicted or forecasted, we typically update our O&M expenditure forecasts during the year. As with our capital investments, one of our largest annual sensitivities for O&M expenditures is severe weather. The amount of O&M we spend on weather-related events, such as storm restoration and floods, can vary greatly from one year to the next. In addition, the Distribution business unit will periodically receive a request from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. When a greater need for expenditures in a particular area is identified, we try our best to re-prioritize and reallocate our budgeted O&M dollars while still operating within our overall O&M budget. However, there are times where circumstances dictate that, in order to maintain safe, reliable service at the levels our customers expect, we will need to spend more than our overall budget would allow to properly address certain items that come about during a given budget year.

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 25 below highlights the variability of O&M spending over and above base labor and transportation (i.e., overtime, materials, contractors) for storm restoration events from 2014 to 2018.

Table 25
2014-2018 Annual O&M Storm Restoration Expenses
(Dollars in Millions)

2014 Actual		2015 Actual		2016 Actual		2017 Actual		2018 Actual	
NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur
$3.0	$2.8	$2.6	$2.3	$2.8	$2.6	$1.1	$1.1	$1.9	$1.7

As shown in Table 25, the Company experienced a moderate increase in O&M expenses related to storm restoration due to severe weather in 2014 and

2016, but nothing as significant as the $6.35 million NSPM ($6.0 million Minnesota jurisdiction) storm restoration expenses incurred by the Company due to a series of severe storms in the Twin Cities in 2013. Thus far in 2019, we are forecasting storm expenses of $5.0 million or $2.6 million higher than the average of the previous five years. This increase is the result in a greater than average number of storms for 2019 as compared to prior years.

Q. HOW DOES THE COMPANY MAKE CHANGES TO THE O&M BUDGET DURING THE YEAR?

A. During the current year, we are routinely monitoring our O&M actual expenditures as compared to the budget and identifying any variances of significance as they materialize. As budget pressures are identified in certain areas or programs, we review options to mitigate those pressures as best we can. One mitigation option is to reallocate from other areas of the budget where funds for budgeted work of a lower priority and/or more discretionary nature (in the short-term) to cover the areas or programs experiencing the budget pressures. Such reallocations are considered as long as the amount of funding needed to cover the budget pressure is within a level that can be prudently covered within our overall budget allocation. If the amount of the budget pressure is too significant to accommodate via reallocation, such as in years where we have had significant storm activities driving larger deviations to O&M budgets, we then seek adjustments to year-end targeted expenditures where we would forecast an overall expenditure level exceeding our overall Distribution O&M budget. Significant deviations from existing budgets must be formally requested of and granted or denied by the Finance Council.

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 then 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.

Q. WHAT STEPS DOES DISTRIBUTION TAKE TO MINIMIZE O&M COSTS?

A. The Distribution business unit takes many steps to minimize the amount of growth in our annual O&M expenditures. We are continuously looking for ways to leverage productivity gains and new technology to become more efficient. One such productivity gain we have leveraged more recently was work with our Supply Chain Organization in 2017 that allowed us to negotiate contract extensions with our key electric and gas contractors in exchange for rate reductions in certain key activities they perform on our behalf. Within this same effort we increased the number of activities our contractors perform on a "unit-cost" basis vs. "time & equipment" which is expected to yield additional cost savings. Distribution Operations is also in the process of reviewing many of our current work processes in a concerted effort to streamline these processes while at the same time enabling a better experience for our customers. It is expected that the streamlining of certain processes will produce efficiency gains that will result in O&M cost reductions.

C. O&M Functions

Q. WHAT TYPES OF O&M FUNCTIONS ARE INCLUDED IN THE DISTRIBUTION O&M BUDGET?

A. There are five primary functions included in the O&M budget. These five functional areas are:

Core Poles and Wires: This activity includes two key areas:

- *Development of New Assets.* This relates to non-capital costs associated with new distribution capital assets.
- *Operation and Maintenance of Existing Assets.* This category covers the bulk of the day-to-day operations and maintenance surrounding the Distribution assets. This includes activities associated with the performance of core electric distribution work, including equipment maintenance, underground cable fault repair, storm repair, and inspections.

Pole Programs: This category includes both the programmatic annual inspections of poles as well as the replacement of poles identified to be in need of replacement from our formal pole inspection program. It also includes the transferring of our electric distribution facilities on foreign owned poles (e.g., CenturyLink Poles) when those poles are replaced by the foreign utility. While the activity itself is very much part of our Core Poles & Wire category defined above, we have now broken this out separately due to the volumes of these types of work activities. We also include in this category activities associated with pole attachments such as Cellular Antenna Projects as requested by cellular companies.

Distributed Generation: The additional O&M expenditures are to cover the cost for our distribution engineering area to study the feasibility (technical and operational) of distributed generation connection requests at various points of our distribution system.

Vegetation Management: This activity includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages.

Damage Prevention: This category includes costs associated with the location of underground electric facilities and performing other damage prevention activities.

While these are the main areas for O&M costs within Distribution, other budgeted functions include items such as engineering, supervision, metering, outdoor lighting, and administrative and general expenses. These other functions are relatively small compared to the larger categories discussed above and their expenditures are included in the Core Poles and Wires function. Table 26 provides a historic look at actual O&M expenditures from 2016 to 2018, as well as forecast O&M expenditures for 2019 (half year actuals and half year forecast), and budgeted expenditures for 2020 to 2022 by these Distribution functions.

Table 26

Distribution O&M Comparison by Function

(Dollars in Millions)

Function	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget	2021 Budget	2022 Budget
Core Poles and Wires	$68.6	$69.4	$77.8	$78.6	$72.9	$77.7	$75.2
Pole Programs	$2.0	$2.5	$3.4	$2.7	$2.7	$3.0	$3.0
Distributed Generation	$0.7	$1.0	$0.5	$2.7	$1.5	$2.0	$2.0
Vegetation Management	$23.3	$26.8	$27.0	$29.0	$28.2	$28.9	$28.4
Damage Prevention	$9.3	$8.7	$8.1	$8.3	$8.5	$8.6	$8.6
AGIS	$0.0	$0.0	$0.0	$0.6	$2.8	$4.5	$6.8
Total	**$104.0**	**$108.3**	**$116.8**	**$121.9**	**$116.6**	**$124.7**	**$124.0**

Q. HOW DO THE 2020 TO 2022 O&M BUDGETS COMPARE WITH 2018 ACTUAL O&M COSTS FOR THESE FUNCTIONS?

A. As shown in Table 26, the 2020 through 2022 O&M budgets average $5.0 million higher than 2018 actuals. The primary drivers of the increase are two years of labor/non-labor escalations at approximately $2.1 million per year ($4.2 million total), an additional $1.5 million in incremental Vegetation Management, plus the start of the ISI Initiative for another $1.5 million. While 2018 actuals include $4.5 million of Puerto Rico mutual aid, this was partially offset by an increased level (-$2.0 million) of line transformer first set credits taken in 2018 that will not repeat in the budgeted years of 2020 to 2022.

Q. CAN YOU EXPLAIN WHY THE INCREASE IN LINE TRANSFORMER FIRST SET CREDIT WAS LIMITED TO 2018?

A. The incremental line transformer first set credits is limited to 2018 due to a particular issue we experienced with one of our transformer suppliers in 2018 which caused us to order a number of additional units from an alternative supplier to mitigate the risk of our normal supplier not meeting their production commitments. However, by the end of 2018, the normal supplier did end up delivering on most units ordered although a number of those much later than needed. The redundant purchases between the normal and alternate suppliers are what cause the incremental first set credits which are not expected to be repeated in future years.

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

A. The 2020 through 2022 O&M budgets average $0.1 million less than the 2019 forecasted amount of $121.9 million. The primary driver of the decrease for the budgeted years is that our latest 2019 forecast includes $2.6 million unusual weather and storm event costs over and above what we would typically expect on an annual basis. When normalized for this, the budgeted years are approximately $2.5 million higher than 2019 year end forecast. This increase is driven by the incremental programs of AGIS and ISI Initiative. The annual Labor/Non-Labor escalation of $2.1 million is mostly offset by annual go-forward productivity improvement reductions for 2020 through 2022 related to the scheduling improvements I discussed earlier.

1. Core Poles and Wires

Q. WHAT IS INCLUDED IN THE CORE POLES AND WIRES CATEGORY?

A. This category covers the majority of day-to-day maintenance of our distribution facilities, including O&M expense associated with overhead asset maintenance and repairs, underground cable fault repairs, severe weather repair, and miscellaneous inspections. This category also includes O&M costs associated with the Cellular Antenna Attachment program. Costs for the Core Poles and Wires budget category for 2016 to 2022 are provided in Table 27.

Table 27

Core Poles and Wires Costs

(Dollars in Millions)

Function	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget	2021 Budget	2022 Budget
Core Poles and Wire	$68.6	$69.4	$77.8	$78.6	$72.9	$77.7	$75.2

Q. HOW DO THE CORE POLES AND WIRE EXPENSES TREND FROM 2018 ACTUALS TO 2020 TO 2022 BUDGETS?

A. As shown in Table 27, the average Core Poles and Wires budget for 2020 to 2022 $75.3 million) is $2.5 million less than 2018 actuals of $77.8 million. However, if 2018 actuals are normalized for Puerto Rico mutual aid ($4.5 million) and increases first set credits (-$2.0 million), 2018 actuals are $4.0 million less than the 2020 to 2022 average budget. This is primarily driven by two years of inflation ($4.2 million) plus an incremental $1.5 million for the ISI Initiative and an average of $0.8 million in incremental training requirements, partially offset by approximately $1.0 million of productivity improvement reductions (across the two years of 2019 and 2020).

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE CORE POLE AND WIRES COSTS.

A. Efforts to minimize our expenditures in the Core Poles and Wires category include use of "joint-contractors" for proactive pole replacement activity and leveraging of more unit pricing for our core electric activities that are contracted out. Starting in 2013, Distribution started awarding more of its contract workload via newly established unit price contracts versus our traditional "Time & Equipment Rate" contracts. This use of unit pricing helps incent our contractors to become more efficient given that they are only paid based on a fixed price per activity completed versus the actual amount of time they spent on activities. As mentioned previously, in 2017 we also implemented an effort in partnership with our Supply Chain Organization to extend the contracts with our key electric and gas contractors in exchange for some rate reductions. The Core Pole and Wire category will also benefit from the cost reductions we are expecting to derive out of our centralized scheduling process described earlier in my testimony.

2. Pole Program

Q. PLEASE EXPLAIN THE POLE PROGRAM.

A. As described previously, the Pole Program category includes the programmatic inspection and the O&M component of the replacement of poles identified to be in need of replacement from our pole inspection program. This category also includes the O&M costs associated with transferring our electric distribution facilities that are located on another utilities' owned poles (e.g. CenturyLink Poles) when those poles are replaced by the other utility. The volumes of required pole inspections and replacements we are forecasting to take on in 2020 and beyond is expected to remain somewhat consistent with 2019 levels as the percentage of poles referred for replacement from our formal testing program has remained fairly steady the past five years averaging 11 percent of all poles tested.

We also include in this category activities associated with pole attachments such as Cellular Antenna Attachment as requested by cellular companies. Cellular companies such as Verizon, AT&T, T-Mobile, and Sprint request us to attach their equipment to our transmission and distribution facilities (poles and towers). We pay for a qualified electric contractor to perform these attachments. Such requests are reimbursable but are taken back into the Company as revenue and therefore do not get credited back to the business unit O&M budgets.

3. Distributed Generation

Q. PLEASE EXPLAIN THE DISTRIBUTED GENERATION COLUMN IN TABLE 26.

A. These O&M expenditures are to cover the cost for our distribution engineering area to study the feasibility (technical and operational) of distributed generation connection requests at various points of our distribution system.

Q. WHAT IS DRIVING THE INCREASE IN DISTRIBUTED GENERATION EXPENSES STARTING IN 2019 AND CONTINUING THROUGH 2022?

A. Starting in 2019, we have seen an increase in the number of distributed generation connection requests throughout our system. This is a trend that we expect will continue through 2022 as more and more of solar companies seek to develop additional solar garden sites within Xcel Energy's Minnesota Jurisdiction.

4. *Vegetation Management*

Q. WHAT IS INCLUDED IN THE VEGETATION MANAGEMENT BUDGET CATEGORY?

A. Vegetation Management is generally activity associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on and adjacent to Xcel Energy's rights-of-way to limit preventable vegetation-related interruptions. The Company has established a five-year routine maintenance cycle for its distribution facilities, generally meaning that vegetation around our electric facilities will be maintained every five years.

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 NSPM distribution system. Being as close as practicable to 100 percent on a five-year cycle will better ensure that preventable tree-related interruptions are minimized, public and employee safety is addressed, and various regulatory compliance requirements are met.

Q. WHAT CHANGES IN VEGETATION MANAGEMENT DO YOU ANTICIPATE FOR 2020 THROUGH 2022?

A. The NSPM Vegetation Management budget is approximately $28.2 million for 2020, $28.9 million for 2021, and $28.4 million for 2022. This is very consistent with the average actuals/forecast of $27.6 million for the years 2017 – 2019.

Q. HOW DOES THE COMPANY BUDGET FOR VEGETATION MANAGEMENT?

A. The Company budgets for Vegetation Management annually based primarily on the number of line-miles of transmission and distribution circuits needing to be maintained on an annual basis in order to maintain 95 percent or better on-cycle performance with our overall Vegetation Management Program. To maintain this on-cycle performance, varying miles of circuits come due each year that were last maintained five years previous and need to be maintained again. Annual budgets are prepared based on the line-miles coming due in the given year, the degree of difficulty (degree of forestation) associated with those circuits, and the forecasted contract rates in effort for the given budget year.

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

A. The main cost drivers in this category are the number of line-miles due in a given year to maintain on-cycle performance, degree of difficulty (forestation) associated with scope of annual circuits due, and finally, the contract labor rates of our primary contractors.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE VEGETATION MANAGEMENT COSTS.

A. The Company has taken several steps to minimize cost increases for Vegetation Management including:

- Bundling the entire volume of work across all operating companies to increase leverage when negotiating pricing with contractors;
- Controlling costs through rigorous negotiations with contractors which includes open-book, transparent pricing methods;

- Using formal contractor evaluation systems (competitive environment) to evaluate contractors against each other based on a set of known and measureable performance measures including cost and quality;
- Performing quality assurance programs such as work completion and contractor crew evaluations; and
- Implementing new technologies such as a new scheduling software package implemented by our Vegetation Management group to better optimize our Vegetation Management scheduling. This software provides a common system for Company and contract personnel to plan, manage, receive and document completion of work, and track quality assurance inspections. It also aids in managing the activity and cost data associated with the all the work. Through this, the system helps facilitate the most efficient deployment of resources for completion of the work, as well as evaluation of completed work.

5. 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. As mentioned earlier in my testimony, we rely heavily on contractors for our Damage Prevention program.

Q. PLEASE EXPLAIN THE INCREASE FROM 2018 ACTUALS TO THE 2020 TO 2022 BUDGETS FOR DAMAGE PREVENTION.

A. Damage Prevention costs increased by only $0.4 million in the 2020 budget compared to 2018 actuals. This represents an average annual increase of 2.4 percent over the two years from 2018 to 2020. This increase is primarily driven by an expected 2.1 percent increase in the number of locates forecasted for 2020 versus 2018 actuals, plus an inflationary factor to cover the latest expected rates from our main damage prevention contractors. Table 28 below provides historic and forecasted locates from 2016 to 2022.

Table 28

2016-2022 Electric Locates

NSPM Electric							
	2016 Actuals	**2017 Actuals**	**2018 Actuals**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
No. of Electric Locates	444,773	427,791	459,499	459,799	469,032	478,413	487,981

Q. HOW DOES THE COMPANY BUDGET FOR DAMAGE PREVENTION?

A. The budget for Damage Prevention is based on several factors, including our most recent historical annual locate request volume trends, regional economic growth factors including new housing starts, and the contract pricing of our Damage Prevention service providers estimated to be in effect for the given budget year.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN DAMAGE PREVENTION COSTS.

A. We have changed how we manage our internal resources recently and were able to improve our productivity so far in 2015 by 23 percent over 2014, resulting an estimated $600,000 worth of savings for both our gas and electric customers throughout NSPM. Specifically, we have eliminated some tasks, rearranged locator territories, and partnered with our workforce to identify certain work practices that could be changed to make sure we are working as efficiently as possible. We have incorporated these savings into our going-forward budgets. Additionally, in more recent years we have adjusted our screening areas for our dispatch technicians resulting in additional efficiency savings of approximately $60,000 for NSPM electric per year.

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 ISI initiative, which require increased O&M to implement. As a result, our O&M cost levels demonstrate a balance between reasonable and prudent management while enabling implementation of necessary capital investments.

V. AGIS INITIATIVE

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

A. This section of my testimony is focused on describing the work that the Distribution organization will be completing as part of the Company's AGIS initiative. The AGIS initiative is a multi-year project that will transform our distribution system into an intelligent and highly automated system. Our vision for this future distribution system is one that incorporates and leverages technology throughout our system to gather and utilize data to better meet our customers' electric needs and enable increased levels of DER.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. First, I will provide an overview of the AGIS initiative and the different components of this initiative. I will also describe the current limitations of the distribution system and how these limitations are, in part, driving the need for the AGIS initiative. Specifically, there is a need to bring our electric distribution system in line with current technologies to improve management and operation of the distribution system, support increasing DER, and to keep pace with our peers in terms of reliability performance.

Next, I will discuss in detail the four AGIS components that the Company is seeking recovery for in this rate case: (1) AMI; (2) FAN; (3) FLISR; and (4) IVVO and describe the work that the Distribution organization is undertaking to install these components. I also provide detailed support for recovery of both the capital and O&M costs associated with this work during the term of the multi-year rate plan. As discussed by Mr. Gersack, the Company is requesting approval to recover the costs of the capital investments and O&M

expense for the components of AGIS that we propose to implement during the term of the multi-year rate plan, and is also requesting that the Commission certify these projects so the Company may request recovery of costs for 2023 and later in subsequent rider filings (subject to all other requirements of rider recovery). Accordingly, while I focus this discussion somewhat on the term of the multi-year rate plan, I also provide support for the Distribution portions of the broader AGIS initiative, consistent with the Company's Integrated Distribution Plan (IDP) being filed concurrently with this rate case.

Finally, I provide support for the cost estimates and benefit calculations utilized in cost-benefit analysis (CBA) model presented in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala. My testimony is organized by the following topic areas. I note that a detailed discussion of FAN is provided by Mr. Harkness.

- <u>Overview of AGIS</u>
- <u>Limitations of Current Distribution System</u>
- <u>Grid Modernization Efforts to Date</u>
  - ADMS
  - TOU pilot
- <u>AMI</u>
  - Overview of AMI
  - Interrelation of AMI with other AGIS components
  - AMI Implementation
  - Benefits of AMI

- Distribution's Costs of AMI
- Alternatives to AMI
- Interoperability
- Minimization of Risk of Obsolesce

- <u>FAN</u>
  - Overview of FAN
  - FAN Implementation
  - Distribution's Costs of FAN
- <u>FLISR</u>
  - Overview of FLISR
  - Prior Certification Request for FLISR
  - FLISR Implementation
  - Benefits of FLISR
  - Costs of FLISR
  - Alternatives to FLISR
  - Interoperability
  - Minimization of Risk of Obsolescence
- <u>IVVO</u>
  - Overview of IVVO
  - Interrelation of IVVO with other AGIS Components
  - IVVO Implementation
  - Benefits of IVVO
  - Costs of IVVO
  - Alternatives to IVVO
  - Interoperability

- Minimization of Risk of Obsolescence
- AGIS Distribution Overall Costs and Implementation

Q. WHAT OTHER COMPANY WITNESSES ARE DISCUSSING THE AGIS INITIATIVE?

A. Mr. Gersack provides an overview of and policy support for the Company's AGIS initiative and certain Program Management costs. Specific information on the IT integration and cyber security support for AGIS is provided by Mr. Harkness. Company witness Mr. Christopher C. Cardenas provides information on how AGIS impacts Customer Care, including the Company's existing meter contract and how AGIS will impact meter reading, customer billing, and the Company's plan for customers selecting to opt-out of AMI meters. The cost-benefit analysis (CBA) model prepared by the Company is discussed by Dr. Duggirala.

A. Overview of AGIS

Q. WHAT IS THE AGIS INITIATIVE?

A. The AGIS initiative is a comprehensive plan to advance Xcel Energy's distribution system. This modernization will start with implementing foundational advanced grid initiatives that provide immediate benefits for customers while also enabling future systems and capabilities. AGIS will help to bring about an intelligent, automated, and interactive electric distribution system that will allow operators more visibility into the system, customers greater access to timely energy information, and enable future products and services for our customers.

Q. WHAT ARE THE FOUNDATIONAL COMPONENTS OF AGIS?

A. The foundational components of AGIS are the Advanced Distribution Management System (ADMS), including the Geospatial Information System (GIS); Advanced Metering Infrastructure (AMI); the Field Area Network (FAN); Fault Location Isolation and Service Restoration (FLISR); and Integrated Volt-VAr Optimization (IVVO).

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.
- *Integrated Volt-VAr Optimization (IVVO)* is an additional application within ADMS, which automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, energy consumption, and provides increased distribution system capacity to host DER.

Q. HAS THE COMPANY SOUGHT AND RECEIVED COMMISSION APPROVAL FOR ANY OF ITS GRID MODERNIZATION INVESTMENTS?

A. Yes, two advanced grid investments have been certified in the Company's biennial grid modernization reports. 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.[6] The implementation of ADMS is currently on track to be completed in April 2020. The Company is not seeking cost recovery for ADMS in this case as these costs will remain in the

[6] *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).

TCR Rider. I discuss ADMS here as it is a foundational component of the AGIS initiative and this background is helpful to understanding how other AGIS components operate in conjunction with ADMS.

In addition, the Company sought and obtained Commission certification for a proposed TOU pilot on August 7, 2018.[7] The TOU pilot requires the installation of AMI meters and associated FAN components to provide customers with pricing specific to the time of day energy is used. The Company proposes TOU Pilot costs incurred during the MYRP be included in base rates. I discuss Distribution's support for these costs below.

Q. WHAT ACTIVITIES WILL THE DISTRIBUTION BUSINESS UNIT PERFORM TO IMPLEMENT AGIS?

A. There are three primary functions that Distribution will perform to implement the AGIS initiative:

- *Installation*: At a high level, Distribution will be responsible for installing and configuring the field devices such as the AMI meters, reclosers, capacitors, sensors, and communications equipment to implement AMI, FAN, FLISR, and IVVO.
- *Operation*: Distribution will also operate the ADMS and its applications such as FLISR and IVVO. Specifically, Distribution operates the associated equipment for these applications, such as switches, reclosers, and capacitors. The Distribution Control Center will be the primary users, with the newly created Grid Management team ensuring its accuracy, availability, and effectiveness. Our Grid Management team

[7] *In the Matter of Xcel Energy's Residential Time of Use Rate Design Pilot Program*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST (Aug. 7, 2018).

will monitor system performance and data integrity to ensure the improvements made to GIS data continue to provide accurate ADMS solutions.

- *Maintenance*: The Distribution Business unit will provide maintenance for the field-based equipment. When possible, maintenance activities such as firmware upgrades will be performed remotely. We note that several types of equipment reside on poles in the "power zone," and require the specialized skills of qualified line workers to access.

Q. WHICH COMPONENTS OF AGIS WILL YOU DISCUSS IN YOUR TESTIMONY?

A. The capital and O&M investments for AGIS are divided between Distribution and Business Systems. I provide primary support for the costs and implementation related to the AMI meters, procurement and installation of pole-mounted FAN devices, and the procurement and installation of the intelligent field devices required for FLISR and IVVO.

As explained by Mr. Harkness, Business Systems has primary responsibility for the IT infrastructure and IT services that will integrate the various components of the AGIS to allow these new application and field devices to communicate with and deliver data to the Company's existing applications. Mr. Harkness will also discuss the cyber security measures that the Company will implement to protect the advanced distribution network as well as the underlying data that it gathers. Table 29 below summarizes which witness support the specific components of the AGIS initiative.

Table 29

AGIS Program Witness Support

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

Q. CAN YOU PROVIDE AN OVERVIEW OF THE DEPLOYMENT TIMELINE FOR THE AGIS COMPONENTS?

A. Table 30 below provides an overview of the deployment timeline of the various AGIS components. I provide more detailed timelines below as part of my discussion of each individual AGIS component.

Table 30

AGIS Foundational Program	Anticipated Deployment Timeline
AMI	AMI Meter install for TOU pilot: 2019-2020 AMI Meter install for Mass Deployment: 2021-2024
FAN	FAN installation for TOU pilot: 2019-2020 FAN installation for AMI mass deployment: 2020-2023
FLISR	Limited testing in 2020; FLISR device install: 2020-2028
IVVO	Limited testing in 2021; IVVO device install: 2021-2024

Q. HOW ARE AGIS COSTS PRESENTED IN YOUR TESTIMONY?

A. The AGIS costs presented in my testimony are provided at either the NSPM Total Company electric level or the Minnesota electric jurisdiction level. This differs from cost presentation in the non-AGIS sections of my testimony, where all Distribution costs are presented at the Minnesota electric jurisdiction level. The reason for this difference within my testimony is that we wanted to present AGIS costs consistently across the various pieces of AGIS testimony. The heading for each cost table states how costs are being presented.

Q. WHAT TYPES OF CAPITAL COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS INITIATIVE?

A. The capital costs for Distribution to implement each of the AGIS programs (AMI, FAN, FLISR, and IVVO) generally include material and equipment, labor, and vendor services.

Q. WHAT ARE THE DISTRIBUTION CAPITAL COSTS FOR THE AGIS INITIATIVE THAT YOU ARE SUPPORTING IN THIS CASE?

A. Distribution's AGIS capital additions I am supporting in this rate case are shown in the following table.

Table 31

AGIS Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	\$1.8	\$22.2	\$110.9
FAN	\$2.8	\$5.4	\$0.0
FLISR	\$3.1	\$8.0	\$5.8
IVVO	\$0.0	\$4.1	\$6.7
Total	**\$7.7**	**\$39.7**	**\$123.4**
There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.			

These AGIS capital additions are also set forth in Exhibit___(KAB-1), Schedule 2 to my Direct Testimony. I provide additional details and support for Distribution's capital costs below, organized by AGIS component.

For the years beyond 2020-2022, I discuss at a higher level the anticipated work to be done and the reasonableness of underlying assumptions for Integrated Distribution Plan (IDP) and CBA model purposes. Exhibit___(KAB-1), Schedules 4, 5, and 6 to my Direct Testimony also includes currently anticipated expenditures used in our CBA beyond 2022.

Q. WHAT TYPES OF O&M COSTS WILL DISTRIBUTION INCUR TO IMPLEMENT THE AGIS INITIATIVE?

A. Distribution's AGIS related O&M costs include labor, contractor, vendor services, and materials.

Q. WHAT ARE DISTRIBUTION'S O&M COSTS FOR AGIS IMPLEMENTATION THAT ARE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. The forecasted AGIS O&M expenses for Distribution are shown in the table below. I provide additional details and support for the Distribution O&M costs below, organized by AGIS component.

Table 32

AGIS O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$2.3	$3.3	$5.0
FAN	$0.1	$0.2	$0.4
FLISR	$0.1	$0.3	$0.2
IVVO	$0.0	$0.4	$0.8
Total	**$2.6**	**$4.2**	**$6.5**
There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.			

Exhibit___(KAB-1), Schedules 4, 5, and 6 to my Direct Testimony also includes currently anticipated expenditures used in our CBA beyond 2022.

Q. TO WHAT EXTENT ARE THE DISTRIBUTION CAPITAL COSTS PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN THE COMPANY'S TRANSMISSION COST RECOVERY RIDER (TCR) FILINGS AND ITS 2018 IDP FILING?

A. The TCR filings presented information on only ADMS, as that is the only certified project for which the Company has sought cost recovery to date. Project costs for the TOU pilot in the Company's 2017 Grid Modernization report and the foundational AGIS projects in the Company's 2018 IDP filing were presented at a higher level because the Company was not yet proposing cost recovery of those initiatives at that time. Further, these filings were based on information available at that time, whereas the current rate case and 2019 IDP filings present more up-to-date information. Lastly, as I describe later, the Company's plan for FLISR has been updated since these prior filings. As a result, this rate case presents the most current information on costs as our planning and data have evolved.

Q. WHAT IS THE DIFFERENCE BETWEEN THE COST ESTIMATES IN THE MYRP AND THE LONGER TERM COST ESTIMATES?

A. While these cost assumptions in the longer term estimates are reasonable and well-supported based on the information available today, they are not intended to reflect specific budgets as in a standard rate case budget. Rather, they are subject to refinement like all costs that will be incurred several years into the future. This is consistent with Mr. Robinson's discussion of all Company projections that represent work to be completed in the longer-term. However, I believe these cost estimates are reasonable, and I explain the support for them as part of my discussion of each AGIS component.

Q. WHAT SORT OF GOVERNANCE IS IN PLACE TO MANAGE THE COSTS AND IMPLEMENTATION OF THE AGIS PROJECTS?

A. Distribution employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These include long established processes in the area of competitive vendor sourcing and pricing negotiations. In addition, the AGIS program has a dedicated Project Management Office to govern all areas within the program. Mr. Gersack discusses overall AGIS governance in his testimony.

B. Limitations of the Current Distribution System

Q. HOW WAS XCEL ENERGY'S DISTRIBUTION SYSTEM ORIGINALLY DESIGNED, AND HOW DOES THIS DESIGN LIMIT THE CAPABILITIES AND OPERATION OF THE SYSTEM?

A. Xcel Energy's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. This design limits the amount of information and visibility that the Company has regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to rely heavily on manual and local control schemes to operate and lacks connectivity to easily share information between different portions and components of the system. These different system limitations can be categorized as:

- Limited Visibility;
- Manual Control; and
- Limited Connectivity.

1. Limited Visibility

Q HOW DOES THE LACK OF VISIBILITY BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM AND THE CUSTOMER EXPERIENCE?

A. Since the existing distribution system only measures limited data on a small number of points on the distribution system (primarily at substations), the Company has little insight into the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, the Company has little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, the Company has to send workers out into the field to gather this information.

Q. HOW DOES THIS LACK OF VISIBILITY BEYOND THE SUBSTATION LEVEL IMPACT THE COMPANY'S ABILITY TO IDENTIFY OUTAGES?

A. Since we do not have visibility into the system beyond the substation level, we rely on customers notifying us via phone or website/app of outages. Our Outage Management System (OMS) then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once we know the portion of the system that is out, we must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages, and leaves our customers without power for longer periods of time.

Q. HOW DOES THIS LACK OF VISIBILITY IMPACT THE COMPANY'S ABILITY TO MONITOR AND CONTROL VOLTAGE LEVELS ON THE SYSTEM?

A. Because the Company does not have visibility into the system beyond the substation level, the Company does not have insight into voltage issues on the system or the ability to efficiently manage the voltage level on the system. Similar to outage information, we rely on customers to report either high or low voltage issues. To maintain required voltage levels, the Company keeps the voltage level at the substation that is at a high end of the appropriate voltage level at all times. This helps ensure that under any conditions the last customer on the system will have voltage within the acceptable range. However, operating the system at higher voltage levels is more costly as it uses more energy and because many end use devices do not operate efficiently at higher voltage levels.

Q. HOW DOES THE LACK OF VISIBILITY IMPACT THE DISTRIBUTION SYSTEM'S ABILITY TO ACCOMMODATE DISTRIBUTED GENERATION?

A. We do not have the ability to accurately measure the amount of distributed generation that is flowing onto or leaving the system. Rather, we rely on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because we must ensure adequate voltage and protection at all times, such conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. This is because the output of distributed generation sources is highly variable and can lead to operational complexities such as protection or voltage regulation concerns. For example, when there are high levels of distributed generation on a feeder, protective equipment such as reclosers or substation breakers may not operate as intended because they are unable to differentiate between loads, distributed generation, and a system fault. Should this occur, there is a risk that a faulted portion of the system would remain energized and present a hazard. While Minnesota currently has low levels of distributed generation relative to some other states, it will be important for the distribution system to have the capability to accommodate increasing levels in the future.

Q. HOW DOES THE LACK OF VISIBILITY AND INFORMATION IMPACT THE CUSTOMER EXPERIENCE?

A. The current AMR system is largely limited to providing the Company with customer usage information necessary to support customer billing. As a result, we cannot provide customers with timely power usage information to enable them to manage their electric usage more efficiently. Additionally, while the system does measure voltage to quantify energy use, it is unable to provide that data through the communication network, and thus cannot alert the Company of either high or low voltage issues.

2. Manual Control

Q. HOW DOES THE LIMITED NUMBER OF REMOTELY CONTROLLED DEVICES BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM?

A. The current distribution system's operation relies on mostly manual and local control schemes that require human intervention to complete an operation. For example, field switches are manually operated switches for nearly all feeders. If there is a fault on any feeder segment, the circuit breaker will open at the substation. When this occurs, a field crew has to patrol the feeder to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads. After the crew locates the fault, they manually open immediate upstream and downstream connecting switches to isolate the faulty feeder section. Then, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. Automating this process will reduce customer outage durations, enable quicker responses to faults, and reduce crew field time.

3. Limited Connectivity

Q. HOW DOES THE COMPANY CURRENTLY COMMUNICATE WITH SUBSTATIONS, FIELD DEVICES, AND METERS?

A. For many years, the Company has communicated with its substation through leased telephone circuits with widely varying capabilities, especially in rural areas, or through expensive microwave installations. Connecting field devices (switches, etc.) with communications networks has been limited due to the expense and complexity of managing these circuits. Although, we have been able to successfully operate the system for many years under these conditions, advancements in technology can now support communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These advanced applications cannot be supported with the Company's current communication network. These improvements will allow the Company access to information to better manage the system and respond to outages, and to provide our customers with access to near real-time data on their energy usage. Further, the rise of small-scale DER located on the grid edge (i.e., near or behind customer meters), has created a need for improvements to accommodate these resources.

4. Xcel Energy's Vision for the Future of the Distribution Grid

Q. CAN YOU DESCRIBE XCEL ENERGY'S VISION FOR THE FUTURE OF THE DISTRIBUTION GRID?

A. Our vision for the future distribution grid is one that utilizes advances in technology to improve our monitoring and operation of the grid for the benefit of our customers. Our AGIS investments will provide us timely and accurate information about what is happening on all portions of the grid from our substations down to each individual customer's meter. These investments will also have the necessary automation and intelligence to address any problems quickly and efficiently. In some cases, these insights will alert us to situations likely to result in an outage (such as overloaded equipment) before an outage occurs. The increased number of field sensors and devices will also provide the Company with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of DER and other electric technologies such as EVs.

Additionally, as discussed by Mr. Gersack, the advanced grid investments will provide the foundation for new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. Further, as discussed by Mr. Harkness, the advanced grid will include security protocols that will detect and remedy cyber and physical threats to our system.

Q. WHY IS IT IMPORTANT TO MAKE THE PROPOSED AGIS INVESTMENTS AT THIS TIME?

A. As discussed in the next section, while the Company has taken certain steps to modernize the grid, now is the time to build on these foundational investments and to begin a more significant advancement of the grid through our AGIS initiative. The need for these AGIS investments is the result of a number of factors including system needs, the maturity of technology, changing customer needs and expectations, and increasing amounts of DER that is anticipated in the near future. Together, these factors drive the need to make the proposed AGIS investments in modernizing our distribution system. These investments will greatly enhance our distribution system's performance and our ability to meet our customers' needs and expectations for their electric service provider now and in the future.

C. Grid Modernization Efforts to Date

Q. WHAT HAS BEEN XCEL ENERGY'S APPROACH TO GRID MODERNIZATION?

A. Our strategy for grid modernization has been a building block approach. That is, we have focused our efforts first on developing the core components that form the foundation to build upon to construct and enable more advanced components. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks including the Department of Energy's Next Generation Distribution Platform (DSPx) framework.[8] This approach also allows us to sequence our investments to yield the greatest near-term and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO UPDATE THE DISTRIBUTION SYSTEM IN RECENT YEARS?

A. One of the steps that we have taken is utilizing our equipment replacements as an opportunity to deploy new equipment that has the greater functionality necessary for a modern grid. An example of this strategy is replacement of electro-mechanical relays with solid-state relays that are not only communication-enabled but are also capable of providing fault data that an ADMS system can use to calculate probable fault location. This allows for faults on our system to be more quickly identified thus improving our response time. Additionally, we are replacing voltage regulators that have

[8] *See* Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

reached the end of their service life with regulators that have controls that identify reverse-power flow and react accordingly, which will facilitate integration of distributed generation onto the system. Beginning in 2015, we have deployed power line sensors on our system that aid our efforts to locate faults more quickly – improving our responsiveness to outage events, and thus the customer reliability experience.

The Company has also installed autonomous, proprietary automated switching systems on portions of its 34.5 kV system. Since these system use a proprietary, single-purpose communication network, they must be specifically designed for the portion of the grid they cover, and the system must be re-programmed when system topology changes. Where these devices have been installed, these systems have improved system reliability, proving the value of the FLISR concept. Going forward, we plan to leverage ADMS's broader FLISR capabilities, bringing reliability benefits customers served by our larger 13.8 kV systems.

Q. HAS THE COMPANY PREVIOUSLY SOUGHT AND RECEIVED COMMISSION CERTIFICATION OF GRID MODERNIZATION INVESTMENTS?

A. Yes, as mentioned above two advanced grid investments have been submitted for certification in biennial grid modernization reports and approved by the Commission. In its 2015 Biennial Grid Modernization Report, the Company outlined the ADMS initiative, which was submitted for certification and subsequently approved on June 28, 2016. In its 2017 Biennial Grid Modernization Report, the Company outlined its AMI and TOU pilot program and certification was approved in the Commission's August 7, 2018 Order.

1. ADMS

Q. WHAT IS ADMS?

A. ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

Q. HOW DOES ADMS ENABLE OTHER GRID MODERNIZATION COMPONENTS?

A. Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, IVVO and FLISR in the near-term, while preparing the Company to implement advanced applications like Distributed Energy Resource Management System (DERMS) in the future.

The GIS data improvement needed to enable ADMS also furthers grid modernization efforts related to DER. Specifically, this effort will help DER adoption by improving the GIS model which is used for system planning and for hosting capacity analysis. The data collection and improvements will reduce the amount of time that planning engineers spend preparing each model for analysis. The verification and population of additional data attributes will also help our designers validate capacity necessary for EVs.

Q. WHAT IS THE TIMING FOR IMPLEMENTATION OF ADMS?

A. ADMS software has an expected in-service date of April 2020 when the system will be tested and go live to control a subset of the distribution system. The plan is to continue to expand the modeled system over the next several years, enabling additional benefits of ADMS including coordination with the FLISR and IVVO deployments.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO ADMS IN THIS RATE CASE?

A. No. The Company has sought recovery for the costs for ADMS in the TCR Rider and proposes to keep ADMS in the TCR Rider through the multi-year rate plan period.

2. TOU Pilot

Q. WHAT IS THE TOU PILOT?

A. The TOU pilot implements new residential TOU rates for select customers in the Twin Cities metropolitan area, providing customers with pricing specific to the time of day energy is consumed. This pilot requires installation of AMI meters to measure and record customer usage in detailed, time-based formats and requires installation of FAN communication to transmit this data to the Company and customers.

Q. HOW MANY CUSTOMERS ARE PARTICIPATING IN THE TOU PILOT?

A. As part of this pilot, we will deploy approximately 17,500 advanced meters to residential customers in Eden Prairie and Minneapolis. We will also deploy FAN communications to these same areas.

Q. WHAT IS THE TIMING OF IMPLEMENTATION FOR THE TOU PILOT?

A. Our back-office work on AMI and FAN necessary for the TOU pilot began in 2018. In 2019, we commenced installations of both FAN devices and AMI meters and expect this work to be completed during the first quarter of 2020. The TOU pilot – with the new rate structures for participants – is expected to begin in April 2020.

Q. WHAT IS THE PURPOSE OF THIS TOU PILOT?

A. The primary aim of this TOU pilot is to study the impact of rigorously designed price signals and technology-enabled data on customer usage patterns to inform future consideration of a broader TOU rate deployment in Minnesota. The purpose of this pilot is not to study the use of AMI meters because, as I discuss later in my testimony, this technology is proven and widely used by other utilities.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO TOU PILOT IN THIS RATE CASE?

A. Yes. For 2020 and going forward, the Company proposes to recover the costs associated with the TOU pilot as part of this rate case. These costs for Distribution are shown in 35 below.

Table 33

AMI TOU Pilot-Distribution State of MN Electric Jurisdiction (Dollars in Millions)			
TOU Pilot-Distribution	**2020**	**2021**	**2022**
Capital Additions	$1.8	$0.0	$0.0
O&M Expenses	$0.3	$0.0	$0.0

I note that the residential TOU pilot costs are part of the Company's overall AGIS initiative (specific to AMI and the FAN). The TOU costs reflect the estimated portion of the total AMI components that are necessary to implement the residential TOU pilot. In his testimony, Mr. Harkness provides the Business Systems costs necessary to implement the TOU pilot.

Q. WHAT HAS BEEN THE IMPACT OF THESE SYSTEM UPDATES AND PILOT PROGRAMS ON THE OPERATION OF THE DISTRIBUTION SYSTEM?

A. While some of these investments (i.e., the automated devices discussed above) have had a positive impact on customer reliability, these improvements have not corrected the fundamental issues with the operation of the current system – lack of visibility and wide-spread automation. Xcel Energy's distribution system currently lacks real-time visibility into the condition of its entire distribution grid and the customer experience beyond the substation level. As a result, if a customer is experiencing an outage, the Company still primarily relies on the customer to report the outage to know that an outage occurred. In addition, the distribution system continues to lack automated controls that allow the Company to adjust and control individual pieces of equipment from a central location.

The state of technology has reached a point where it is feasible to implement equipment and systems that will provide the Company with the visibility and automation required to operate with increasing levels of DER and higher customer expectations around reliability and information about their power use. While the Company has implemented some of these technologies in a few pilot areas, it is now time to expand this technology to larger portions of our electric grid. In the next section of my testimony, I will describe the foundational components of the AGIS initiative that we plan to implement during the term of the multi-year rate plan.

D. AMI

1. Overview of AMI

Q. WHAT IS AMI?

A. AMI is an integrated system of advanced meters, communications networks, and data management systems that enables secure two-way communication between customer meters and utilities' business and operational systems that enable benefits for both the customer and the utility. AMI meters are able to measure and transmit voltage, current, and power quality data and can act as sensor, providing timely monitoring at the customer's point of service that has a variety of uses for customers and business operations.

AMI is a key element of the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS initiative. The system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, enables greater customer offerings for rates, programs, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy.

The Company plans to deploy approximately 1.3 million AMI meters in Minnesota starting in the third quarter in 2021 and continuing through 2024. This mass deployment of AMI meters builds off the limited AMI meter installation that will be completed in late 2020 as part of the TOU pilot. Xcel Energy will own and operate the AMI meters and the FAN communication network.

Q. DESCRIBE THE ADVANCED METERS.

A. The advanced meters are the key endpoint component of an AMI system that measures, stores, and transmits meter data, including energy usage data from customer locations. The advanced meters can also measure values such as voltage, current, frequency, real and reactive power, and certain power quality events such as sags and swells. Additionally, these meters can detect outage events, restoration events, tampering, energy theft events, and perform meter diagnostics.

Q. HAS XCEL ENERGY SELECTED A SPECIFIC ADVANCED METER?

A. Yes. Xcel Energy has selected the Itron Riva Generation 4.2 advanced meter. This meter will be installed for mass deployment in Minnesota starting in 2021. For the TOU pilot, Xcel Energy will install a different AMI meter, a Landis+Gyr Focus meters equipped with Itron Gen 5 NICs, because the Riva Generation 4.2 advanced meter will not be ready for installation until 2021. The meters installed for the TOU pilot will be replaced by Itron with the Riva Generation 4.2 during the mass deployment at no cost to Xcel Energy. The RFP process that was used to select this meter and vendor are described in greater detail below. This specific meter is the latest model in Itron's Riva family of meters so a photo of this specific meter is not currently available. A photo of a similar model (the OpenWay® Riva CENTRON meter) from the Itron Riva family of meters is provided below in Figure 8.

Figure 8

Q. WHAT IS THE SERVICE LIFE OF THESE ADVANCED METERS?

A. We have assumed a service life for the advanced meters of 15 years in Minnesota for purposes of depreciation and the CBA. The actual physical life of these advanced meters will likely exceed this 15 year service life.

Q. WHAT ARE THE COMPONENTS OF ADVANCED METERS?

A. The components of the advanced meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications); (3) embedded Distributed Intelligence capabilities (described below); and (4) an internal service switch (to support remote connection and disconnection).

Q. WHAT ARE THE FUNCTIONS OF THE ADVANCED METER ITSELF?

A. The primary purpose of the advanced meter is the same as our existing meters – to measure the amount of electricity used by our customers for billing purposes. However, the advanced meters have additional capabilities and can be remotely configured to measure bi-directional and/or time-of-use energy consumption in kilowatt hours (kWh) and demand in kilowatts (kW). An advanced meter that is configured for bi-directional energy measurement measures energy provided by the Company to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to the Company. Energy consumption data for billing purposes can be recorded by advanced meters in intervals as short as five minutes, or longer intervals if desired. The advanced meters also provide granular data regarding voltage and outages as explained further below.

Q. HOW OFTEN WILL AMI METERS COLLECT AND TRANSMIT DATA TO THE COMPANY?

A. The AMI meters will collect and transmit data to the Company a minimum of six times per day or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care employee may request and collect the meter data while on the phone assisting a customer.
- Through the internet portal or smartphone application, as described by Mr. Harkness, a customer could request an on-demand meter reading. This request will provide a customer with near real-time energy information.[9]
- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event.

[9] The terms "near real time" refer to the fact that there is a slight delay (under ten seconds) between the time the data is pulled and when it is received by the customer.

The length of time between the data transmission and the event depends on the type of the event.

- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five minute interval data, and will transmit data to the head-end application every five minutes to make that information available to ADMS. The interrelation between AMI and ADMS is discussed further below.

Q. WHAT ARE THE OTHER CAPABILITIES OF THE ADVANCED METERS?

A. In addition to the ability to measure, store, and transmit interval meter data, advanced meters also have the capability to:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events;
- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;
- Support electric vehicle interconnections;
- Support customer-facing energy conservation technologies (i.e., smart thermostats);
- Support Distributed Intelligence; and
- Support remote connect/disconnect functions for customers taking single-phase service (generally, residential and some small business customers).[10]

[10] The only AMI meters available in the marketplace with remote connection/disconnection switches are single-phase meters.

Q. WHAT ARE THE CAPABILITIES OF THE ADVANCED METER'S TWO-WAY RADIO FREQUENCY COMMUNICATION MODULE?

A. The radio frequency communication module will utilize the Company's communication network (i.e., the FAN) to provide two-way communication between the meter and the AMI head-end application. The AMI head-end application is the operating system that is used to send data requests and commands to an advanced meter, and receive data from the meter. These communications include:

- Transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- Receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals;
- Remotely performing meter firmware upgrades;
- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Q. WILL THE TWO-WAY RADIO MODULE WITHIN THE AMI METERS HAVE THE ABILITY TO COMMUNICATE WITH OTHER DEVICES?

A. Yes. While the primary purpose of the two-way radio is to capture and transmit customer billing data and service quality data from the AMI meter to the Company, there is also a second radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's Home Area Network (HAN) and HAN devices.

Q. WHAT IS A HAN?

A. The HAN is a network contained within a customer's home or business that connects a customer's HAN devices together as well as to customer's AMI meter. A HAN device can be as simple as an in-home energy display that provides real-time energy data. HAN devices can also include thermostats, home security systems, energy display devices, and smart appliances, that when connected through the HAN, these devices can communicate with each other to support energy management functions.

Q. HOW DOES THE COMPANY INTEND TO UTILIZE THE HAN FUNCTIONALITY OF THE AMI METERS?

A. As discussed by Mr. Gersack, HANs vary in the benefits they provide and can be as simple as a dashboard that communicates with the meter to provide real-time energy usage or more complicated networks of devices that are receiving energy usage data from the meter and adjusting operations based on that information. The Company will continue to build and refine our next steps with both advanced grid technologies and customer products and services that will leverage AMI capabilities.

Q. WHAT IS DISTRIBUTED INTELLIGENCE?

A. Distributed intelligence or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is actually needed, such as advanced meters or other "smart" devices on the grid. Since data no longer has to traverse long distances over increasingly constrained networks, these technologies improve the computational speed, efficiency, and capabilities derived from these platforms. Distributed intelligence capabilities in advanced meters and other edge devices opens up a broad array of new uses that will fundamentally transform how customers will use energy in their homes and businesses, as well as how Xcel Energy will be able to optimize its AGIS investments.

Q. WHAT ARE THE EMBEDDED DISTRIBUTED INTELLIGENCE CAPABILITIES OF THE ADVANCED METER SELECTED BY THE COMPANY?

A. Our advanced meters will provide a distributed intelligence platform that is a computer at customers' homes and businesses. This computer uses a Linux-based operating system to conduct localized, at the meter computing, analysis, and data processing that provide customers with new tools to help manage their energy usage and provide Xcel Energy with new tools to manage the grid more efficiently. This capability also allows for the installation of a wide-range of potential applications. In other words, this Distributed Intelligence capability allows for the installation of applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning Xcel Energy interacts with the applications.

Q. WHAT ARE THE POTENTIAL USES OF THIS DISTRIBUTED INTELLIGENCE CAPABILITY?

A. The Distributed Intelligence capabilities allow the AMI meter to run multiple applications at the same time and without the need for instructions from the Company's back-office applications or control room. This type of capability is beneficial because it allows the AMI meters to communicate directly with each other regarding issues, analyze those issues, and to solve problems directly rather than communicating these issues to a back-office system and then waiting for instructions on how to solve the problem. The potential use cases for these applications include:

- Improved and security and awareness,
- Energy usage control and savings,
- Smarter insights about customer energy data and information,
- Smarter controls to better manage and integrate different systems, and
- Identification and alarming for operational issues.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THESE DISTRIBUTED INTELLIGENCE CAPABILITIES COULD BE USED BY THE DISTRIBUTION ORGANIZATION?

A. Xcel Energy is leading the nation in the deployment of Distributed Intelligence in the AMI meters. As a leader in this space, we are working with our meter vendor to design, develop, and implement new applications. Our meter vendor has already begun building a number of applications that can be enabled on the meter. While the specific use of these Distributed Intelligence capabilities will depend on the particular applications employed, I will provide an example of how these capabilities could be utilized to manage demand during peak times to avoid transformer overloads. During a hot summer afternoon when energy use is rising due to air conditioning use, the AMI meters at each customer location would analyze this data in real time. These meters would then share their individual data with the other meters served by a common distribution transformer, calculating and comparing the total load to the capacity of the transformer. The AMI meters would be able to discern when the transformer is approaching overload conditions and determine the most appropriate course of action, which could be reporting, alarming, modulating, or possibly shutting off controllable loads to keep the transformer below its rated capacity. The same concept would help with the integration of electric vehicles, as well. Finally, a transformer's capacity may be challenged by additional PV, as more of our distribution transformers begin to see their peak not from load, but from PV generation in the afternoon when solar production is strong, but loads are low.

Q. WHAT IS THE PURPOSE OF THE INTERNAL SERVICE SWITCH?

A. The internal service switch has the ability to remotely connect or disconnect power to the customer's electric service upon command from the head-end data application. I note that remote connection/disconnection of residential or small commercial customers would require revisions to our existing tariff and Xcel Energy is not currently seeking Commission approval to enable this capability.

Q. HOW IS AMI DIFFERENT THAN THE METERING SYSTEM USED TODAY?

A. The Company currently has an AMR system that has been in place since the mid-1990s. Meter readings are collected and provided to the Company via a proprietary network by Landis+Gyr (Cellnet), our current meter reading services vendor. We have served our customers for 20-30 years via this AMR system. However, AMR is now dated technology and much of the industry has or is moving to AMI meters.

Q. WHAT ARE THE LIMITATIONS OF THE CURRENT AMR SYSTEM?

A. The AMR system in general is a fixed network, one-way communication system with limited functionality that is primarily related to meter reading for billing purposes. As a result, the AMR system has a number of limitations including:

- Inability to measure and record voltage, current, or power quality;

- Lack of real-time view of a customer's metering data;
- Meter readings are transmitted via a single path communication system that precludes the ability to collect necessary data if there is an obstruction on that single communication path; and
- Cannot be reprogrammed or upgraded remotely such that on-site performance of these tasks is required.

These limitations of the current AMR system preclude us from having much visibility into our customer's energy experience, this visibility is invaluable for how we operate and plan our system. As discussed by Mr. Gersack, the AMR system also limits the customer offerings we can currently provide.

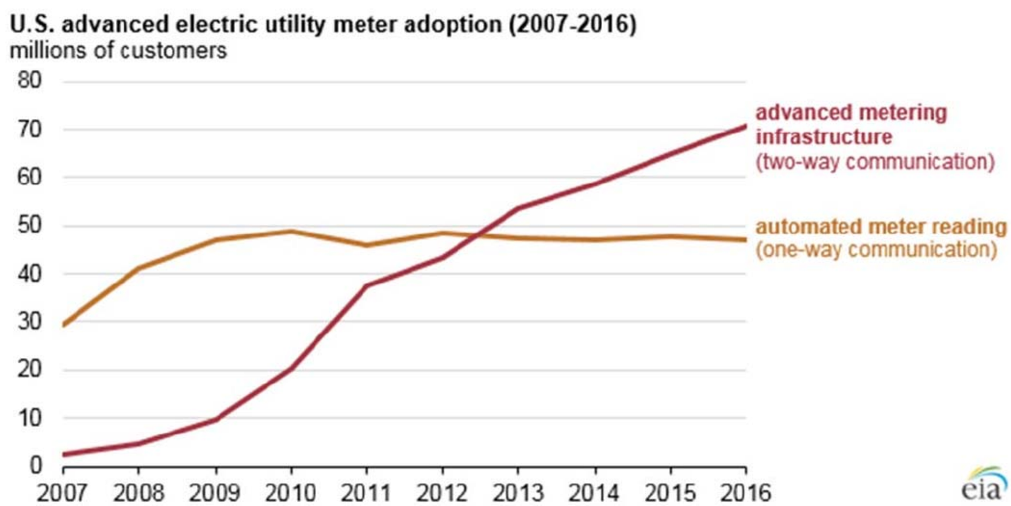
Q. WHY IS IT IMPORTANT TO MOVE FROM AMR TO AMI AT THIS TIME?

A. In addition to the limited functionality of this outdated technology, now is an opportune time to replace this legacy system as we are nearing the expiration of our current AMR meter reading service contract with Cellnet. The current Cellnet contract expires at the end of 2025, with an option to extend it through 2026 at a significantly increased cost. As we are the last remaining customer of the Cellnet system, a contract extension past 2026 is highly unlikely. In addition, Cellnet will stop manufacturing replacement components for the AMR system, including communication modules necessary for meter reading, in 2022. Given that the Cellnet system is a proprietary system, replacement parts are not commercially available from other vendors. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components after 2022.

The expiration of our Cellnet contract comes at fitting time given the current state of the AMI market and its technology. AMI has advanced to the point where it is established meter technology that has widespread adoption. Installation of AMI meters has doubled since 2010 and since the end of 2016 nearly half of all U.S. electric customer accounts have AMI meters. According to the United States Energy Information Administration, and as shown in Figure 9, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR deployment has remained flat.

Figure 9[11]

AMI vs. AMR Installations



In sum, it is the culmination of these several factors: (1) aging and outdated technology with limited functionality; (2) the expiration of the existing Cellnet meter reading contract; and (3) difficulty of obtaining vendor in the future for the AMR system that is driving the need to convert to AMI.

[11] https://www.eia.gov/todayinenergy/detail.php?id=34012.

2. Interrelation of AMI with other AGIS Components

Q. CAN YOU SUMMARIZE THE ROLE OF AMI IN THE OVERALL AGIS INITIATIVE?

A. AMI is a central source of information with which virtually all components of AGIS interact and as such AMI is critical to support certain benefits of the advanced grid such as TOU rates and associated price signals, more efficient distribution management system, and greater customer control over energy usage.

Q. HOW WILL AMI INTERACT WITH ADMS?

A. AMI will also provide the ADMS with timely real and reactive power measurement data that will be used in load flow and IVVO calculations. Further, AMI meters will provide voltage measurements at various points on the distribution system to support IVVO calculations. The information collected by the AMI meters will allow the Company through IVVO to reduce the overall voltage on the system.

The AMI meters will report a power outage or "last gasp" event to the AMI head-end application and report a power-on event when the power is restored. This information will flow from the head-end application to ADMS that will improve the calculations for the fault location and restoration applications.

Q. HOW WILL AMI INTERACT WITH THE FAN?

A. The AMI meters have an integrated network interface card (NIC) that enables them to connect to the WiSUN portion of the FAN network. This enables the transmission of data and commands between the AMI meters and the Company. The meters can also act as a repeater for other mesh network devices, enabling two-way communication between the meters and the mesh network. This function provides increased communication reliability between the AMI meters and the head end application. For example, if the communication signal is weak between the AMI meter and the access point device, the meter may have a stronger communication path to the access point by having another meter (or several meters), act as a repeater to facilitate the communication.

Q. HOW WILL THE AMI METER INTERACT WITH FLISR?

A. The last gasp and power-on information that advanced meters will provide will be available on ADMS which will utilize this data to develop more accurate model and forecasting tools for FLISR. This transfer of data will enable the Company to more precisely locate faulted sections of feeders, which reduces patrol times, and improve FLISR switching plans, which minimizes the outage impact to customers.

Q. HOW WILL THE AMI METERS INTERACT WITH IVVO?

A. As noted above, advanced meters provide voltage information to ADMS from strategic points on the distribution system. The ADMS combines voltage information provided by the AMI meters to calculate voltage levels across the grid. This voltage data becomes more precise and accurate as the number of AMI meters providing this data increases. This voltage information is then used by the IVVO application to operate voltage control devices on the grid, optimizing the voltage levels on the grid while keeping the voltage within the desired bandwidth. Without the AMI meters acting as sensors, the Company would need to deploy stand-alone sensors to implement IVVO. I discuss this further in the alternatives section below.

3. AMI Implementation

Q. WHAT IS THE AMI DEPLOYMENT TIMELINE?

A. We plan to install approximately 1.3 million AMI meters throughout our Minnesota service territory as part of the AGIS initiative starting in the third quarter of 2021. This deployment builds off the limited installation of 17,500 AMI meters planned to be installed in late 2019 as part of the TOU pilot. By the end of 2023, we anticipate that over 90 percent of the meter installations will be complete. Table 34 below provides a summary of the number of meters we anticipate installing per year from 2021 through 2024.

Table 34

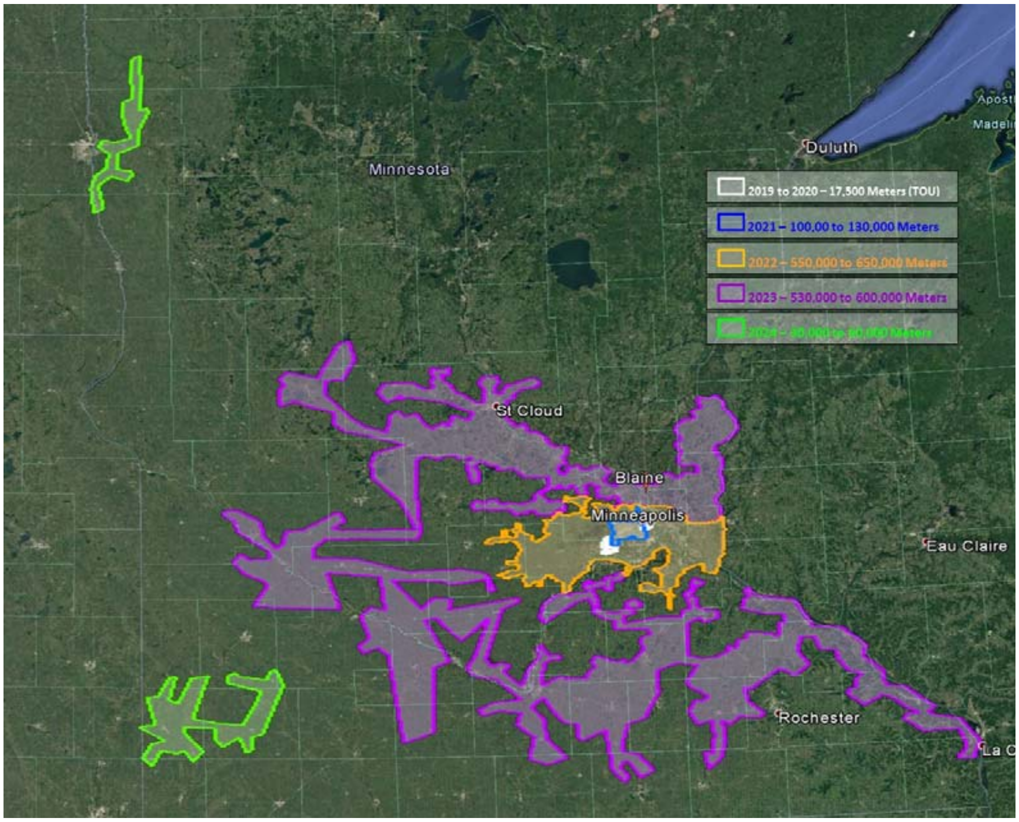
AMI Meter Installation by Year

Year	2021	2022	2023	2024
Number of AMI Meters Installed	100,000 to 130,000	550,000 to 650,000	530,000 to 600,000	30,000 to 60,000

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING WHERE THE AMI METERS WILL BE INSTALLED EACH YEAR?

A. Figure 10 below shows the anticipated deployment schedule for AMI. As shown below, the first meters installed as part of the mass deployment starting in third quarter 2021 are adjacent to and will build off the TOU pilot areas. From there, the deployment will continue to expand outward through 2023 with the final deployments scheduled in our Sioux Falls and Fargo service areas for 2024.

Figure 10



Q. HOW WILL THE AMI METERS BE INSTALLED?

A. The exchange of AMI meters in the field will be performed by trained and qualified contractors under the management and direction of Company employees.

Q. HOW LONG WILL IT TAKE TO INSTALL EACH INDIVIDUAL METER?

A. The time to install each meter will vary depending on the type of service and meter that each customer has but in most cases we expect that the meter exchange for a residential customer to take less than 15 minutes.

Q. WILL INSTALLATION REQUIRE A CUSTOMER'S ELECTRICITY TO BE TURNED OFF?

A. Depending on the type of meter socket the customer has, they may experience a brief outage during installation. Customers do not need to be present during installation. We will provide customers with information about the timing of their AMI installation and what to expect during installation prior to installation. Mr. Gersack will discuss our communications and customer outreach plan in further detail.

Q. WILL THE INSTALLATION AND DEPLOYMENT OF AMI METERS BE INTEGRATED WITH THE COMPANY'S EXISTING INFORMATION TECHNOLOGY?

A. Yes. The advanced meters will be integrated with the Company's information technology system. AMI is data intensive with meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data from the AMI meters comes into the head-end application and, depending on what the data is, it will need to be integrated and made available to the applicable business system in an accurate and timely manner. IT integration is explained in more detail by Mr. Harkness.

4. Benefits of AMI

Q. WHAT TYPES OF BENEFITS DOES XCEL ENERGY ANTICIPATE WILL BE ACHIEVED FROM AMI INSTALLATION?

A. There are four categories of benefits that we expect from implementation of AMI: (1) quantifiable capital benefits, (2) quantifiable O&M benefits, (3) other quantifiable benefits, and (4) non-quantifiable benefits. The quantifiable benefits of AMI were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratios for each AGIS element.

Q. CAN YOU PROVIDE AN OVERVIEW OF THESE FOUR CATEGORIES OF BENEFITS?

A. With respect to quantifiable capital savings, we expect to see benefits in the areas of distribution system management efficiency, outage management efficiency, and avoided meter purchases. With respect to O&M savings, I will discuss quantitative benefits in the categories of field and meter service costs, distribution system management, outage management savings, as well as customer outage reductions. We also anticipate O&M savings in avoided meter reading costs, reduced customer calls, reduction in field and meters services, and improved distribution system spend efficiencies.

With respect to other quantifiable benefits, we anticipate reduction in energy theft, reduced consumption on inactive premises, reduced uncollectible and bad debt expense, load flexibility savings, and carbon emissions benefits. These other quantifiable benefits are discussed by Mr. Cardenas and Dr. Duggirala. Table 35 summarizes the quantifiable benefits of AMI.

Table 35

AMI CAPITAL BENEFITS		
AMI Capital Benefits	**Description of Benefit**	**Witness**
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved capital spend efficiency during outage events.	
Avoided Meter Purchases	AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters.	
Avoided investment of an alternative meter reading system	Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement	
AMI O&M BENEFITS		
AMI O&M Benefits	**Description of Benefit**	**Witness**
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement	Direct Testimony of Mr. Cardenas, Section V(F)
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved O&M efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)

Table 35 (continued)

OTHER QUANTIFIABLE BENEFITS OF AMI		
Other Benefits of AMI	**Description of Benefit**	**Witness**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration	Direct Testimony of Ms. Bloch, Section V(D)(4)
Critical Peak Pricing	Customer demand savings in response to new rate structures.	Direct Testimony of Dr. Duggirala, Section II(B)(1)
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Direct Testimony of Dr. Duggirala, Section II(B)(1)
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.	Direct Testimony of Dr. Duggirala, Section II(B)(1)

A summary of the calculations for all of the quantifiable AMI benefits is provided in Exhibit___(KAB-1), Schedule 7. There are also a number of benefits that are not readily quantifiable. I address three of these non-quantifiable benefits: (1) enhanced DER integration; (2) improved safety for both customers and employees; and (3) improved power quality. Other non-quantifiable benefits are discussed by Mr. Gersack, Dr. Duggirala, and Mr. Harkness.

Q. WHEN WILL CUSTOMERS BEGIN TO SEE THE BENEFITS OF AMI?

A. There is a relationship between when benefits will start to be realized based on when AMI meters are being installed in the field and when back office functionality is enabled via data processing and management systems and integrations with other systems. In general, most benefits will start to be fully realized after full-deployment of AMI meters in 2024. Partial benefits will begin to be realized in the 2023 timeframe.

a. Capital Benefits

Q. WHAT ARE THE CAPITAL BENEFITS FOR AMI THAT YOU PROVIDE SUPPORT FOR IN YOUR TESTIMONY?

A. I describe and provide support for calculation of the following capital benefits of AMI:

- Improved distribution system management efficiency;
- Improved outage management efficiency;
- Avoided meter purchases due to reduced failure rate of new meters; and
- Avoided capital investment of an alternative meter reading system to the existing Cellnet meter reading system.

(1) Distribution System Management Efficiency

Q. WHAT DISTRIBUTION SYSTEM MANAGEMENT EFFICIENCIES WILL BE GAINED AS A RESULT OF AMI?

A. AMI will provide a wealth of information about the workings of the distribution system. This AMI data can be aggregated at varying levels of the distribution system including tap, transformer, and service lines amongst other distribution system equipment. This data will be used by the Company to prioritize distribution grid improvements and more efficiently plan and design the system. Through the aggregated AMI data, we will have greater insights into the nature of the load - specifically load profiles, which will help us evaluate risk. The voltage insights will help us prioritize areas for investments in tap, transformer, and secondary wire replacement. For instance, the AMI data can be aggregated at the transformer level to identify overloaded transformers as well as determining the optimal transformer for replacement transformers. We will also have tools to better understand system losses which will help us evaluate opportunities for investment to minimize these losses. The Company estimated that AMI meters will provide a 1 percent reduction in capital expenditures for Asset Health and Reliability projects and Capacity projects.

Q. HOW WAS THIS BENEFIT CALCULATED?

A. The Company examined past projects in the Asset Health and Reliability and Capacity categories and determined that 1 percent was a reasonable estimate of the capital expenditure reduction that will result from the data provided AMI meters. In addition, the Company's 1 percent estimated benefit is consistent with the percentage utilized in the CBA performed by Ameren Illinois in 2012 when it sought approval for its AMI deployment (Ameren Business Case).

To calculate this benefit, the Company utilized an average of the actual capital expenditures in the capital budget categories of Asset Health and Reliability and Capacity over a five-year period 2014 through 2018. This average capital expenditure was then multiplied by 1 percent to calculate the reduction in capital expenditures resulting from AMI.

(2) Outage Management Efficiency

Q. DESCRIBE THE IMPROVEMENT IN OUTAGE MANAGEMENT EFFICIENCY THAT WILL BE ACHIEVED FROM THE INSTALLATION OF AMI METERS.

A. AMI will enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System (OMS). Power loss information is identified by an AMI meter's last gasp. Outage notification from the AMI meters will provide the Company with a timelier and more accurate scope of an outage. The automated outage information provided by the AMI meters will then assist the Company in restoring power more quickly. AMI will also enable more efficient outage restoration because the AMI will provide more detailed outage location information that will reduce the time and expense in locating the outage. Overall, because of these increased outage management efficiencies, AMI enables quicker response and restoration to customer outages to minimize inconveniences or economic losses that could be experienced by the customer.

Q. HOW DID XCEL ENERGY QUANTIFY THESE OUTAGE MANAGEMENT EFFICIENCY BENEFITS?

A. Xcel Energy estimates that AMI will result in a 10 percent reduction in storm-related capital costs due to the efficiencies gained from the information provided by the AMI meters. To develop this percentage, the Company examined historic storm-related capital expenditures in light of the improve outage information that AMI will provide and determined that a 10 percent reduction was a reasonable, if not conservative, estimate of expected reduction that will result from the data provided AMI meters.

The Company utilized an average of the storm-related capital expenditures for the five-year period between 2014 and 2018. This average storm-related capital expenditure was then multiplied by 10 percent to calculate the benefit resulting from AMI deployment.

(3) Avoided Meter Purchases

Q. DESCRIBE THE AVOIDED METER PURCHASE BENEFIT THAT WILL RESULT FROM DEPLOYMENT OF THE AMI METERS?

A. AMI meters will have a lower failure rate as compared to our existing AMR meters. As a result, there is a cost savings associated with not having to replace these failed AMR meters. The benefit from avoided AMR meter purchases, however, is partially offset by the cost of ongoing replacement of AMI meters due to normal failure rates.

Q. HOW DID THE COMPANY CALCULATE THE BENEFIT ASSOCIATED WITH AVOIDED METER PURCHASES?

A. Based on historical data from 2014 to 2018, Company calculated that the average percentage failure rate of our current AMR meters is approximately 1.92 percent per year. In contrast, the AMI meter vendor provided an estimated failure rate of 0.5 percent per year for the new AMI meters based on their own experience and testing.

The total failure cost associated with replacing a failed meter has three components: meter cost, installation cost, and total number of failed meters per year. The total failure cost for replacing AMR meters was based on our current actual meter and installation costs. The total failure cost for replacing

AMI meters was based on the meter and installation costs included in our contract with our selected meter vendor. The difference between total AMR failure costs and the total AMI failure costs was used to determine the cost savings associated with AMI.

(4) Avoided Cost of Alternative Meter Reading System

Q. DESCRIBE THE BENEFIT ASSOCIATED WITH AVOIDING AN INVESTMENT IN AN ALTERNATIVE METER READING SYSTEM?

A. As mentioned above, our current meter reading contract is set to expire in 2025 (or 2026 with a costly extension) and the Company will need to find a replacement meter reading system. One option is to replace the current AMR Cellnet meter reading system with another basic AMR meter reading alternative such as a drive-by system. Since the deployment of AMI will eliminate the need to replace the existing AMR Cellnet meter reading with an alternative drive-by meter reading system, these avoided costs are a benefit of AMI.

Q. HOW DID THE COMPANY DETERMINE THE COSTS FOR AN ALTERNATIVE DRIVE-BY SYSTEM?

A. PSCo employs an AMR drive-by system in Colorado and as a result, the Company was able to utilize actual costs of that system to estimate the upfront and projected capital and ongoing operating costs to deploy a similar system in Minnesota. To translate the costs from Colorado to Minnesota, the Company also prepared an analysis of possible routes for the drive-by meter reading system to better estimate these costs. The capital cost components include meters, meter installation, other deployment costs, vehicles, equipment and material, and project management. We also estimated reasonable O&M costs that include meter reading labor, vehicles, equipment maintenance, customer claims, and contingencies.

Q. HOW DID THE COMPANY CALCULATE THE AVOIDED COST BENEFIT ASSOCIATED WITH NOT HAVING TO DEPLOY AN ALTERNATIVE DRIVE-BY SYSTEM?

A. The total costs of this AMR drive-by system was assumed as the benefit of AMI as these costs would not be incurred if AMI is deployed.

b. O&M Benefits

Q. WHAT ARE THE O&M BENEFITS FOR AMI THAT YOU PROVIDE SUPPORT FOR IN YOUR TESTIMONY?

A. I describe and provide support for calculation of the following O&M benefits of AMI:

- Reduction in O&M for field and meter services;
- Improved efficiency in distribution maintenance; and
- Improved outage management efficiency.

The O&M benefit associated with implementing AMI as opposed to a drive-by meter reading system (i.e., avoided O&M for drive-by meter reading costs) that I mentioned in the prior section above is discussed by Mr. Cardenas.

Q. IN GENERAL, WHAT O&M BENEFITS DOES THE COMPANY ANTICIPATE AS A RESULT OF IMPLEMENTING AMI METERS?

A. AMI will enable Xcel Energy to perform several functions remotely that otherwise require a field visit to the customer premise. As a result, O&M cost savings will be realized through reductions in field personnel trips to repair damaged equipment, to confirm power has been restored after an outage, to reconnect and disconnect customers, and for voltage investigations.

(1) Reduced Field and Meter O&M Expenses

Q. WHAT ARE THE TYPES OF FIELD AND METER SERVICE EXPENSES THAT WILL BE REDUCED BY IMPLEMENTING AMI?

A. Since AMI meters will have the ability to provide billing, power, and voltage information to the Company on command, there will be a reduced need to send personnel to the field to gather this information. This will result in O&M savings in several areas:

- *Reduction in Outage Trips due to Customer Equipment Damage*: Our current AMR system requires crews to be dispatched to verify outages. Sometimes these outages are due to damaged customer equipment and not utility damaged equipment. Under the new AMI system, AMI meters will have two-way communications to the meter and the Company can verify whether there is power at the meter thus pointing to a likely customer problem. This would help reduce field trips while also assisting customers in identifying the likely cause of the outage.
- *Cost Savings from Remote Connect Capability*: AMI enables remote connection and disconnection of residential type service without the need to dispatch crews. This will result in personnel and transportation cost savings due to the reduction in field visits.
- *Reduction in "Ok on Arrival" Outage Field Visits*: AMI will allow the Company to test for loss of voltage at the service point and detect both outage conditions and to know when restoration is complete. As a result, AMI implementation will help eliminate unnecessary field trips

to customer premises that result in field personnel finding no electric service issues upon arrival.

- *Reduction in Field Visits for Voltage Investigations*: When notified of a potential voltage problem, the Company currently sends a technician to investigate. AMI enables the elimination of unnecessary trips when proper voltage can be verified remotely, and helps us prioritize and dispatch the most appropriate crews if the voltage is outside of the appropriate range.

Q. HOW DID THE COMPANY CALCULATE THE O&M SAVINGS ASSOCIATED WITH THE REDUCTION IN FIELD TRIPS DUE TO DAMAGED CUSTOMER EQUIPMENT?

A. To calculate this O&M savings, Company first determined the average number of trips per year between 2014 and 2018 for damaged customer equipment. This average was 1,796 trips per year. The Company also determined that AMI would result in a 50 percent reduction in the number of trips per year for damaged customer equipment. To determine the cost benefit from this 50 percent reduction in the number of trips, the Company utilized the average O&M costs for a trip based on historic cost estimates from 2014 to 2018. To calculate the benefit amount, the Company applied a 50 percent reduction to the average number of trips and then reduced this amount by 50 percent and multiplied this by the average O&M cost. The cost of each trip is the sum of dispatch savings (wages multiplied by time saved) plus crew savings (same as dispatch), and overhead savings. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated trip costs.

Q. HOW DID THE COMPANY DETERMINE THAT AMI WOULD RESULT IN A 50 PERCENT REDUCTION IN THE NUMBER OF TRIPS DUE TO DAMAGED CUSTOMER EQUIPMENT?

A. The Company examined historic data for trips required due to damaged customer equipment and determined that 50 percent was a reasonable, if not conservative, estimate of this reduction. AMI will allow the Company to, in most cases, to determine remotely whether there is power at the meter thus pointing to a likely customer equipment issue. The only times when a field trip may still be required are when there are network communication issues, weather issues, or an issue inside the meter that will prevent us from remotely obtaining the necessary information to fix the issue. We expect that these situations will be limited and as a result the 50 percent reduction is conservative. By way of comparison, the Ameren Business Case assumed a 90 percent reduction in damaged customer equipment field trips due to AMI.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS FROM THE REMOTE CONNECTION CAPABILITY PROVIDED BY AMI?

A. An average of 4,416 residential disconnect and reconnect trips per year were completed by the Company between 2014 and 2018. To derive these benefits, the Company estimated that AMI will reduce the labor costs for these trips by approximately 70 percent for manual disconnections and 95 percent for manual reconnections. The Company believes that 70 percent is a reasonable reduction for disconnects as manual disconnection may still be required in approximately 30 percent of cases such as when the Company does not have accurate customer contact information or where a customer has opted out of AMI. The Company believes that 95 percent is a reasonable reduction for reconnection as manual reconnection may be required in cases where there is a poor communication connection to the AMI meter. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

Q. WILL THE COMPANY NEED COMMISSION APPROVAL TO ENABLE THE REMOTE RECONNECT AND DISCONNECT CAPABILITIES OF THE AMI METERS?

A. Yes, I understand that enabling these capabilities will require Commission approval. These regulatory filings are discussed by Mr. Cardenas. While these capabilities will require regulatory approval, the ability to remotely connect and disconnect customers is a benefit of AMI meters and as a result is included in the CBA.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS ASSOCIATED WITH "OK ON ARRIVAL" OUTAGE FIELD VISITS?

A. Between 2014 and 2018, there was approximately average of 7,464 trips per year where field crews found no issues with a customer's electric service upon arrival. The Company assumed that these trips would be reduced by approximately 50 percent as a result of AMI. This 50 percent reduction is reasonable, if not conservative, given that the AMI meter will allow the Company the ability to remotely determine whether or not power is on at an individual meter. There will of course be relatively rare instances where the Company will not perform this remote diagnostic test due to either network connection or weather issues. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS ASSOCIATED WITH THE REDUCTION IN FIELD VISITS FOR VOLTAGE INVESTIGATIONS?

A. There was an average of 2,858 trips per year from 2014 to 2018 for voltage investigations. The Company assumed that AMI would reduce these voltage investigation trips by 50 percent. This 50 percent reduction is reasonable given that the Company will be able to obtain detailed voltage information remotely from AMI meters. In certain cases, the Company may still need to go to a customer premise to investigate voltage information due to either a poor communication connection or in cases where the voltage information is inconclusive. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

(2) Improved Distribution Maintenance Efficiency

Q. WHAT ARE THE IMPROVED EFFICIENCIES IN DISTRIBUTION MAINTENANCE FROM AMI THAT WILL RESULT IN O&M BENEFITS?

A. AMI data can be aggregated at varying levels of the distribution system that include the tap, transformer, and service lines amongst other distribution system equipment. This data will be used by Distribution to prioritize grid improvements and more efficiently plan and design the system. This data can then be used to determine optimal timing for installation and replacement of distribution assets as well as optimizing inventory levels. As discussed in the capital benefits section above, the Company estimated that these efficiencies will provide a 1 percent reduction in capital expenditures for Asset Health and Reliability projects and Capacity projects. This benefit is the O&M portion of this benefit which the Company determined would amount to a 0.1 percent reduction in the O&M expenditures for Asset Health and Reliability and Capacity projects. To determine this 0.1 percent, the Company examined past O&M costs for these types of projects.

(3) Outage Management Efficiency

Q. HOW WILL AMI REDUCE O&M COSTS DURING OUTAGES?

A. AMI enables an automated outage information system that allows the Company to deploy crews more efficiently to outage areas, especially during storm outages, ensuring verification that all customers in an area have been restored before dispatching the crew to the next location.

Q. HOW DID THE COMPANY CALCULATE O&M SAVINGS FROM THE IMPROVED EFFICIENCIES IN OUTAGE MANAGEMENT AS A RESULT OF AMI?

A. The Company utilized the average yearly O&M costs for storm related activities from 2014 to 2018 ($2,100,000) and then calculated 10 percent reduction in these costs due to AMI. As discussed, AMI will enable quicker responses to outages by our field crews as they will have more detailed information as to the location of the outage thus reducing time and expense. This 10 percent reduction is reasonable based on the Company's review of historic O&M storm information. This 10 percent reduction is also in alignment with the Ameren Business Case. Ameren serves customers in a similar area of the country we expect our storm expense O&M reductions to be similar.

c. Other Benefits of AMI

Q. OTHER THAN THE CAPITAL AND O&M BENEFITS THAT YOU DISCUSS ABOVE, ARE THERE OTHER QUANTIFIABLE BENEFITS OF AMI?

A. Yes. The other quantifiable benefits include:

- Reduced consumption on inactive meters,
- Reduced uncollectible/bad debt expense,
- Reduced theft/meter tampering,
- Load flexibility benefits associated TOU rates (peak demand reduction, customer energy price savings, and reduced emissions).
- Reduced outage duration.

The majority of these other benefits of AMI are discussed by other Company witnesses. Mr. Cardenas discusses the first three benefits and Dr. Duggirala discusses the load flexibility benefits. I will discuss the last benefit (reduced outage duration).

Q. HOW WILL AMI REDUCE THE LENGTH OF OUTAGES?

A. AMI meters send a last gasp message to the utility before the meter loses power. Not all last gasp messages make it, but usually enough messages are received to help the utility adequately determine which customers are affected. This outage data helps utility personnel respond more quickly to fix problems with the end result being that customers' power is restored more quickly. Another benefit of AMI meters is verification of power restoration. Restoration verification is accomplished when a meter reports in after being reenergized. This will provide automated and positive verification that power has been restored to all customers, there are no nested outages, and all associated trouble orders are closed before restoration crews leave the areas.

This reduces costs, increases customer satisfaction, and further reduces outage duration.

Q. HOW DID THE COMPANY CALCULATE THE CUSTOMER BENEFIT ASSOCIATED WITH THIS REDUCTION IN OUTAGE DURATION?

A. The Company estimated that AMI meters will help reduce outage length resulting in direct benefits for customers. Three main improvement areas were evaluated for Customer Minutes Out (CMO) reduction: (1) better identification of nested outages during storm events; (2) reduction in response time for single customer events; and (3) faster response to tap level events. For each activity, the Company determined the value of these CMO based on the Interruption Cost Estimate (ICE) Calculator developed by Lawrence Berkeley National Laboratory (LBNL).[12]

Q. WHAT IS THE ICE CALCULATOR?

A. The ICE Calculator estimates the value of an interruption from a customer viewpoint. LBNL bases the value for commercial and industrial customers on their costs due to an outage, and for residential customers, the amount that they would be willing to spend to avoid an outage. It incorporates studies, analyses, and econometric models to determine these values and is widely used by utilities and government agencies across the country to estimate the costs of service interruptions and the value of reliability improvements.

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[12] The ICE Calculator is available at: https://icecalculator.com/home.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE OF THE BENEFIT RELATED TO BETTER IDENTIFICATION OF NESTED OUTAGES DURING STORM EVENTS?

A. During a large storm event, when a customer can experience multiple outage issues, it can be difficult to determine if all customers' power has been restored in an area after identifying and completing outage work at a single location. The ability to check which customers' power has been restored by automatically "pinging" their AMI meter will improve efficiencies in restoration work.

To calculate this benefit, we utilized outage data on Major Event Days (MEDs) (as this data typically captures large storms) for the years 2015-2017. CAIDI was determined to be 572 minutes for a storm day. The CAIDI value was inserted into the Customer Minute Out (CMO) value calculator. The result is a dollar savings per CMO of $0.65. The average annual number of CMO during major event days was 115,264,755 minutes. It is estimated that the ability to automatically ping AMI meters would reduce the number of CMO by 0.5 percent. This was multiplied by the $0.65 to calculate the total annual benefit of $374,610 which when divided by the number of meters for an estimated benefit of $0.30 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE OF THE REDUCTION IN RESPONSE TIME FOR SINGLE CUSTOMER EVENTS?

A. Today, when a single customer contacts Xcel Energy about an outage, it is frequently an outage issue on the customer's side of the meter or not an outage at all. First, Xcel Energy attempts to contact the customer and verify the outage. Frequently, this verification fails and the when the first responder arrives at the customer site the issue is then identified as a non-Xcel Energy outage event. Often while Xcel Energy is responding to the first event another single customer outage is in the queue, waiting for work on the first event to be completed. Installation of AMI will allow the Company to determine the first event is a non-Xcel Energy outage event, allowing Xcel Energy to more quickly respond to the other event.

The benefit of this reduced wait time was calculated based on single customer outage event data for 2015-2017 using only non-MEDs data. The average CAIDI for these events was 184 minutes. These outages added up to a total of 3,147,220 CMO for three years. It was estimated that half of the time the CMO could be reduced by 20 percent for an annual savings of 104,907 CMO. The CAIDI value was inserted into the CMO value calculator. The result is a savings per CMO of $0.75. This $0.75 was multiplied by the annual CMO reduction of 104,907 CMO to calculate the total annual savings of $78,680, which when divided by the number of meters equate to an estimated benefit of $0.06 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE RELATED TO A FASTER RESPONSE TO TAP LEVEL EVENTS?

A. Xcel Energy prioritizes outage events by the number of customers impacted by an outage. On a typical day, when an incoming outage is identified as a single customer event, work in progress continues and response to the single customer event waits until existing work is complete. Typically a multi-customer event is initially identified as a single customer event. Only when the outage event is identified as a multi-customer event, is work reprioritized. AMI will provide greater visibility into outages and will allow work to more quickly be reprioritized allowing for a faster response time to larger outage events.

The benefit of this faster response time was calculated using data from multi-customer events from 2015-2017 for non-MEDs. The average annual number of customers experiencing an outage or 396,883 customers was multiplied by three minutes (the estimated average time for more than one customer to report an outage) for an annual CMO savings of 1,190,649 minutes. The CAIDI value for multi-customer events, 271 minutes, was inserted into the CMO value calculator. The result is a savings for a per customer minute out of $0.70. This $0.70 was multiplied by the annual CMO reduction of 1,190,649 CMO to calculate the total annual savings of $833,454, which when divided by the number of meters equate to an estimated benefit of $0.67 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE TOTAL OUTAGE REDUCTION BENEFIT?

A. The total dollar value for each of these three categories of benefits was summed for a total benefit of $1.03 per customer. The Company then calculated the total outage reduction benefit by multiplying this $1.03 value by the total number of meters to be deployed.

d. Non-Quantifiable Benefits

Q. WHAT ARE THE ANTICIPATED NON-QUANTIFIABLE BENEFITS OF AMI?

A. Xcel Energy anticipates qualitative benefits in several areas, including:

- Improved customer choice and experience, leading to customer empowerment and satisfaction;

- Enhanced distributed energy resource integration;
- Environmental benefits of enhanced energy efficiency;
- Improved safety to both customers and Xcel Energy employees; and
- Improvements in power quality.

I will discuss the last four of these non-quantifiable benefits, and Mr. Gersack discusses the first benefit related to improved customer choice and experience.

(1) Distributed Energy Resource Integration

Q. HOW WILL AMI ENABLE GREATER DISTRIBUTED GENERATION INTEGRATION?

A. AMI will provide more timely and more granular data on the flow of energy to and from our customers. With this load flow information, and with voltage, current, and power quality data provided from AMI to ADMS, system operators will be able to facilitate the integration of greater amounts of distributed generation on to the system. In addition, the bi-directional capabilities of the AMI meters will allow the ability to perform net metering for our DER customers without the need to change out the existing meter.

Additionally, the AMI system will capture voltage and usage data which can be compared with nameplate or operational limits of our equipment. Using this data, we will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of EVs (load) or high reverse flows (such as solar generation). It is our intention to leverage AMI data for this purpose, which will allow us to enable DER while at the same time maintain reliability and power quality for each of our customers.

Further, AMI will enable the creation of more accurate load profiles which are used by ADMS to create better system models for planning and operational purposes. Initially, ADMS will be using relatively few profiles to represent typical customer loads. Once AMI has been in place for a year, we will create more refined profiles which will significantly improve our models. This data will then support planning and operational modeling, enabling us to more accurately identify problems (or the lack thereof) as more load or DER hosting is contemplated for the system.

Finally, AMI meters have bi-directional capabilities that can be utilized by our DER net metering customers. Currently, when a customer who is eligible for net-metering adds generation, we replace the meter with to enable bi-directional flow. With AMI we will be able to effect this change remotely saving the cost of a meter change.

(2) Energy Efficiency

Q. WHAT ARE THE POTENTIAL ENVIRONMENTAL BENEFITS OF AMI?

A. AMI is expected to result in greater energy efficiency by the customer and the Company. As previously stated, AMI will provide the customer more information on energy usage and will enable the Company to offer additional time-based rates or other offerings that allow more customer choice in controlling their energy usage and costs. To the extent these energy efficiency gains reduce the need for generation they will contribute to lower energy emissions.

(3) Safety Improvements

Q. HOW WILL AMI IMPROVE SAFETY FOR BOTH CUSTOMERS AND XCEL ENERGY EMPLOYEES?

A. AMI enables the meters to be read, remotely disconnected and reconnected, and enables remote diagnostics of the customer's service, thereby minimizing safety risks for Company representatives and the customer. For example, AMI will allow us to more rapidly assist emergency personnel by remotely shutting off power to a burning building as opposed to dispatching a truck to perform the disconnection. In addition, while AMR meters can do some level of automated reading, they cannot minimize meter diagnostic and connect/disconnect visits to the same extent as AMI meters. AMI provides several remote functions that eliminate or minimize the need for the Company to visit the meter, which minimizes the intrusiveness to the customer and potentially reduces safety concerns of unknown people accessing their property. Reducing these visits also reduces employee safety risks associated with customer pets and traversing unfamiliar properties.

(4) Power Quality Improvements

Q. HOW WILL AMI PROVIDE IMPROVEMENTS IN POWER QUALITY?

A. AMI will monitor and provide power measurement and voltage data at more points within the distribution system, which will be used in load flow and IVVO calculations to enable improvements in power quality. This will help ensure voltage is within acceptable limits from the substation all the way to the customer's point of service. In other words, better monitoring of power quality reduces the potential for out-of-range voltages that may interfere with electronic devices in customers' homes or businesses. Additionally, timely power outage and restoration will enable improved outage management and contribute to improved power quality to our customers overall.

5. AMI Costs

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION WILL UNDERTAKE IN 2020, 2021, AND 2022 TO IMPLEMENT AMI.

A. Xcel Energy plans to install 1.3 million advanced meters between 2021 and 2024. The Distribution Business Area will be primarily responsible for the purchase and installation of these meters. Distribution will support the installation of the new AMI meters as well as removal, retirement, and disposal of the existing AMR meters, but the installation and removal work will primarily be done by the meter vendor. Distribution will also test and configure all AMI hardware to ensure that it is working properly and is able to integrate with other products and applications.

Q. WHAT ARE DISTRIBUTION'S COSTS FOR THE FULL AMI DEPLOYMENT?

A. Distribution's costs for AMI are broken down by capital additions and O&M costs through the term of multi-year rate plan in Tables 36 and 37 below. I will describe these costs in further detail below.

Table 36

AMI Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$1.8	$22.2	$110.9

Table 37

AMI O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$2.3	$3.3	$5.0

a. Distribution Capital Costs for AMI

Q. WHAT ARE THE PRINCIPAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTATION OF AMI?

A. Distribution's capital costs associated with implementing AMI are: (1) the meters; (2) meter installation; (2) vendor project management; (3) AMI operations; and (4) testing equipment.

Q. WAS DISTRIBUTION PRIMARILY RESPONSIBLE FOR DEVELOPING THE COSTS FOR AMI?

A. Distribution is responsible for the costs associated with acquiring and installing the AMI meters. I describe how we developed our forecast for these costs in more detail in my Direct Testimony. Business Systems is responsible for developing the forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Harkness will address the development of those costs.

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S AMI CAPITAL FORECAST?

A. Distribution's AMI capital forecast has five key components: (1) AMI meter purchase; (2) AMI meter installation; (3) vendor project management; (4) AMI operations (external and internal); and (5) testing equipment.

Q. HOW DID DISTRIBUTION DEVELOP THE COSTS FOR THE AMI METERS AND INSTALLATION?

A. The costs for the AMI meters and installation are based on the meter contract with our AMI meter vendor, Itron Inc. (Itron). Additional overheads such as taxes are also included in these estimates.

Q. DESCRIBE THE PROCESS USED TO SELECT THE AMI METER VENDOR.

A. Xcel Energy issued a Request for Proposal (RFP) in March 2018 to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. As part of the RFP process, potential vendors were asked to review the Company's priorities and vision for its AMI solution including the capabilities desired by the Company for this technology. The vendors were then asked to provide precise and detailed responses to numerous technical questions regarding their AMI meter offerings related to the following:

- Technical standards of the their meter;
- Capabilities of their meter;
- Compatibility of their AMI meter with other components of the AGIS initiative;
- Data and cybersecurity safeguards;

- Plan and schedule for technology development, integration, and AMI deployment; and
- Itemized pricing information for their AMI meter and installation.

We received responses to this RFP from four different companies.

Q. HOW DID XCEL ENERGY EVALUATE THESE RFP RESPONSES?

A. Xcel Energy evaluated these responses on a number of factors including: (1) total cost; (2) schedule requirements; (3) core metrology; (4) customer benefits and capabilities; (5) integration with the selected NIC from Silver Springs (which was purchased by Itron, Inc.); (6) future proofing/new technology; (7) commercial terms and conditions; and (8) security.

Q. WERE THERE OTHER CAPABILITIES THAT THE COMPANY DESIRED FOR THE NEW AMI METERS?

A. Yes. The Company was also interested in making sure that the selected AMI meter could support distributed intelligence capabilities. As discussed above, these are computing capabilities within the AMI meter that allows the meter to run different applications. These capabilities were an important consideration as the Company understood the customer facing, operational, and future proofing benefits that these capabilities could provide.

Q. DID XCEL ENERGY SELECT AN AMI METER AND INSTALLATION VENDOR FROM THESE RFP RESPONSES?

A. Yes. Based on an assessment and comparison of the capabilities, price, and schedule commitments provided in the RFP responses from these four different meter vendors, Xcel Energy selected a meter vendor. Xcel Energy issued a Limited Notice to Proceed to that meter vendor in December 2018. However, in late March 2019, Xcel Energy learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and meet the Company's meter deployment schedule set forth in the Limited Notice to Proceed. As a result, Xcel Energy requested that the initially selected vendor provide a schedule for deployment for AMI meters that incorporated the vendor's own NIC and network.

Q. WHAT RESPONSE DID THE COMPANY RECEIVE TO THIS REQUEST?

A. The initial meter vendor's response indicated that it would not be able to integrate their own NIC and network into the meters without a significant increase in cost and a risk of further schedule delays. However, the Company also received a comprehensive proposal from another meter vendor that responded to the initial RFP. This meter vendor was able to meet the Company's requested deployment schedule with the necessary NIC integration, offered the necessary meter capabilities, and offered favorable price and contractual terms. As a result, in May 2019, Xcel Energy selected Itron as its meter vendor and a contract was executed on September 1, 2019 (Meter Contract).

Q. WHY DID XCEL ENERGY SELECT ITRON AS ITS METER VENDOR?

A. The primary factors in the decision were:

- Lowest cost/best overall value for an offering that included distributed intelligence / edge technology;
- Lowest risk solution / least complexity;
- Met Xcel Energy's deployment schedule;

- Single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- Met or exceeded Xcel Energy's core metrology requirements, including distributed intelligence capabilities; and
- Most favorable overall commercial terms and conditions, including for edge technology/distributed intelligence.

A summary of our analysis supporting the selection of Itron is attached is Exhibit___(KAB-1), Schedule 10.[13]

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR THE AMI VENDOR PROJECT MANAGEMENT COSTS?

A. The forecast for AMI vendor project management is set forth in the Meter Contract. The Company's estimates also include internal overheads.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR AMI OPERATIONS RELATED TO INTERNAL AND EXTERNAL PERSONNEL?

A. Cost estimates for internal and external personnel were developed based on the role and number of required personnel required to perform necessary tasks to enable installation and deployment of the AMI meters. The necessary positions include analysts, program and project managers, engineers, and electricians. The cost estimates were determined using average pay scales for the needed positions combined with an estimate the amount of work required by each of these roles during the AMI installation and deployment. The

[13] The Company's RFPs related to the AGIS projects are provided on the AGIS supporting files compact disk provided with Vol. 2B.

Company then determined the appropriate allocation between capital and O&M for these costs based on the type of work being performed.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR TESTING EQUIPMENT?

A. These cost estimates were based on quotes obtained and purchases that were made from our existing vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and we leveraged our relationships with existing vendors to obtain the best cost for this equipment.

b. Distribution O&M Costs for AMI

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

A. The primary components of Distribution's AMI O&M expense relate to: (1) AMI operations (internal and external); and (2) customer claims.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR AMI OPERATIONS?

A. The development of these costs was discussed earlier in the capital section.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR CUSTOMER CLAIMS?

A. Based on input from industry experts, Company estimated approximately $100,000 for small claims from customers associated with meter installations. This total was then spread across the deployment years based on the number of meters deployed in each particular year.

c. Distribution Contingency for AMI

Q. DOES DISTRIBUTION'S AMI FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. The use of contingencies is consistent with project planning practices, especially for large projects. We believe it is appropriate to include a contingency amount at this stage given that the project will be implemented over multiple years, as well as the complexity, size, and integrated nature of this project. Mr. Gersack discusses the overall AGIS project contingencies in his testimony.

Q. WHAT IS THE AMOUNT OF DISTRIBUTION'S CONTINGENCY FOR AMI?

A. The Distribution's AMI budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 26 percent.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE DISTRIBUTION CONTINGENCY ASSOCIATED WITH AMI?

A. Yes. The level of contingency is based on our current risk assessment of items that may impact the final costs of the project. While the Meter Contract dictates much of Distribution's costs for AMI meters and installation, there are still certain unknowns that could impact our final costs. These include: (1) customer access issues; (2) issues with existing electrical wiring to the meter box; and (3) changes to the deployment schedule. Given that the scope of our AMI meter deployment is vast and requires that we replace all of the electric meters throughout our entire service territory, it is important that we have sufficient contingency to account for these potential risks.

Q. PLEASE DESCRIBE THESE POTENTIAL RISKS THAT YOU IDENTIFIED?

A. Customer access issues involve difficulties associated with obtaining access to a customer's meter to remove the existing meter and install a new meter. This could involve a meter located in the basement of a home or a meter located outside that is guarded by an unfriendly dog. These types of access issues could result in increased costs due the increased labor and expense associated with multiple visits that are required perform the necessary work. Issues with existing electrical wiring to the meter box could also lead to increased costs due to the increase in labor and material costs associated with repairing such issues. Given that the existing meters at many customer locations are between 20-30 years old, it is difficult to know at this time the number of such issues that may arise with the existing electrical wiring. Finally, there may be changes to the deployment schedule that could impact final costs.

Q. HOW DID THE COMPANY DEVELOP AN APPROPRIATE CONTINGENCY AMOUNT TO ACCOUNT FOR THESE POTENTIAL RISKS?

A. Based on our assessment of these risks and their potential financial impact we set an overall contingency amount for AMI and then allocated that amount to each year of the AMI deployment based on the amount of work being completed in each year.

Q. DOES THE COMPANY BELIEVE THE CONTINGENCIES WILL BE USED?

A. Yes, to some extent. While the Company does not necessarily anticipate using all of the contingencies, we believe that some amount of contingency will be used based on experience with prior projects. Contingency amounts are included to avoid the need for tradeoffs in schedule and/or scope and functionality. In this way, we can ensure implementation of the project will help maximize benefits for our customers. As Mr. Gersack discusses, there are strict controls on when and how the contingency amounts may be used. The overall AGIS governance structure provides for review and approval of any project changes that will affect the scope, costs, or benefits of implementation. Any changes from budgeted amounts and any specific use of budget contingencies will need approval according to the established AGIS governance processes.

d. AMI Expenditures 2020-2029

Q. WHAT ARE DISTRIBUTION'S CAPITAL EXPENDITURE AND O&M FORECASTS FOR AMI FOR 2020 THROUGH 2029?

A. The tables below provide the Distribution's AMI capital expenditure and O&M forecasts for 2020 through 2029.

Table 38

AMI Capital Expenditures – Distribution NSPM - Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-year Period	10-year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.6	$22.3	$133.9	$179.5	$14.1
*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.					

Table 39

AMI O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.3	$3.3	$5.0	$10.0	$15.7
*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.					

6. Alternatives to AMI

Q. WHAT ALTERNATIVES TO AMI DID THE COMPANY EVALUATE?

A. The Company considered several alternatives to AMI. These alternatives were to: (1) extend the life of the existing AMR meters; (2) replace existing AMR meters as they fail with AMI meters; (3) utilize a different AMR solution with limited TOU capabilities; (4) utilize an AMR drive-by solution; or (5) return to non-AMR, manually read meters. I note that none of these alternatives provide the same benefits and functionality for our customers that are provided by the full deployment of AMI proposed by the Company. AMI meters are essential to an advanced grid that provides our customers and the Company with the data and information to improve our customers' energy experience, and improve reliability, safety, and security of the grid.

a. Extend life of existing AMR meters

Q. CAN YOU DESCRIBE THE CURRENT AMR METERS THAT ARE INSTALLED IN MINNESOTA?

A. The majority of Xcel Energy's electric meters in Minnesota are part of a one-way, transmit-only Radio Frequency (RF) fixed network AMR system. This system mostly provides total energy and demand information once a day based on the type of meter installed. The meter is affixed with a Cellnet module that transmits meter pulse data multiple times a day to pole-mounted network components. While the current AMR system has some ability to support more complex rate designs, such as limited TOU rates, and provides non-usage data, such as a "last gasp" when the power goes out, these meters do not have two-way communication capabilities. Without two-way capabilities, we must dispatch a meter technician to reconfigure a meter's TOU intervals each time a customer wants to change their rate.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THE POSSIBILITY OF EXTENDING THE LIFE OF THE EXISTING AMR METERS?

A. Our current AMR system has been in place since the mid-1990s and has provided substantial value for customers since its installation. However, as I mentioned above, our Cellnet meter reading and vendor support contract expires at the end of 2025. We have the ability to extend this contract for one additional year but at a significant cost increase as compared to prior years. We are the last remaining customer on the Cellnet system such that our ability to extend this meter reading and vendor support contract beyond 2026 is highly unlikely. As a result, our ability to continue to use the Cellnet system for meter reading beyond 2026 would require us to purchase the existing meter reading network, software, and meter modules from Cellnet.

Even if we purchased this system from Cellnet, it would be challenging to continue to operate and maintain this aging system in good working order because Cellnet will stop manufacturing replacement parts for this system in 2022. As this system is proprietary, there are no other vendors that we can utilize to provide replacement parts for this system. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components. Given the inability to find replacement parts for the existing Cellnet meters, Xcel Energy determined that trying to extend the life of these meters beyond the end of the Cellnet contract was simply not a reasonable or prudent alternative.

b. Replacing AMR meters one at a time

Q. DID THE COMPANY CONSIDER REPLACING AMR METERS WITH AMI METERS ONE AT A TIME AS THEY FAIL?

A. Yes, but the Company determined that installing the 1.3 million AMI meters at the same time to all of our Minnesota customers was the best option for several reasons. First, deploying all of the AMI meters at once reduces the cost of installation of each individual meter as there are efficiencies of scale in such a large deployment. Second, the AMI mesh technology that allows the AMI meters to communicate with each other and the utility requires a certain density of meters in a particular area to sustain reliable communications. AMI meters communicate within a mesh to an access point device, and the data is then transmitted to Company. If the Company were to replace meters one at a time, we would need to replace enough meters in a particular area to comprise a sufficient AMI mesh network otherwise communications could be comprised. We would also still need to install portions of the FAN communications network at that time.

Given the complexity associated with the installation of the communication network, the Company determined that best approach was a mass deployment of AMI meters that could be synchronized with the FAN deployment. Third, AMI is an integral component to the overall AGIS initiative. For instance, AMI meters serve as sensors at the customer premise that provide vital information to FLISR and IVVO on power status and voltage level. Without AMI, the Company would need to employ independent sensors that would not be able to match the performance of AMI meters given that they could not be located at the customer's point of service like AMI meters.

c. AMR alternatives

Q. DID THE COMPANY EVALUATE INSTALLING A DIFFERENT TYPE OF AMR METER SYSTEM?

A. Yes. There are several different types of AMR metering systems: (1) two-way RF system; (2) one-way RF system (currently in use in most of Xcel Energy's Minnesota service territory); and (3) a drive-by system. Xcel Energy evaluated each of these AMR systems and a manual read meter alternative and compared their capabilities to the AMI system.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THESE DIFFERENT METER SOLUTIONS?

A. The Company concluded none of these alternative meter systems could match the features and capabilities of the AMI system. Although both the AMI and AMR systems provide billing data, the AMI system provides additional features and information that can be used to support advanced TOU rates, improve outage information, support demand response and distributed generation, and provide timely usage information that consumers can use to save money by managing their use of electricity. A summary comparison of the different meter options to AMI is provided in Table 40 below.

Table 40

Comparison of Metering Capabilities

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
TOU data	● Would support more complex TOU rates and meters can be remotely programmed to capture TOU data	◐ The system supports two tier rates only and meters cannot be remotely programmed to capture TOU data	◐ Xcel Energy billing systems support only two TOU rates and meters cannot be remotely programmed to capture TOU data.	◔ Limited capability. Some meters could support one TOU bin in addition to other metering quantities.	○ Not supported
Interval data	● Capable of measuring and recording more complex interval data sets; supports more interval data lengths	◔ Can only be used for load research purposes and not for billing as data is not revenue grade quality; limited to traditional energy interval data	◐ Data can be used for billing; limited to traditional energy data; limited to 5 or 15 minute interval lengths	○ Not supported	○ Not supported
Real time notification of power outages	● Real-time availability of outage information	◐ Outage notification but not in real-time	◐ Outage notification sent up to meter head-end system	○ Not supported	○ Not supported
Fast response to customer inquires	● Real-time access to customer metering data and diagnostic information	◔ Limited access to customers metering data and meter diagnostic information	◔ Lack of real-time view of customer's metering data and no access to meter real time diagnostic information	○ Not supported	○ Not supported
Support integrated systems that offer customers options for energy conservation and cost management programs	● Technology supports customer side technologies such as smart thermostats, load control devices, etc.	◔ Limited and uncoordinated technology that can allow for such customer facing solutions.	○ Not supported	○ Not supported	○ Not supported

Table 40 (continued)

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Ability to remotely upgrade metering devices e.g. firmware upgrade, meter configuration changes	● AMI offers the platform to remotely perform such functions.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Availability of real-time data e.g. voltage, current, power, etc. that are vital for distributed energy resource monitoring	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported by AMR system. Costly to extend standalone communication systems to all distributed energy resources	○ Not supported by AMR system. Costly to extend standalone communication systems to all distributed energy resources	○ Not supported	○ Not supported
Availability of power quality events e.g. momentary outages for each customer, sags, swells, etc. that are essential for system reliability improvement	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Remote availability of meter diagnostic data useful for remote troubleshooting	● Data available with full AMI systems.	◔ Feature supported to a limited extent.	◔ Feature supported to a limited extent.	◔ Feature supported to a limited extent.	○ Not supported
Remote reconnection/ disconnection	● System supports remote reconnect/disconnect of residential type customers and limited small commercial customers	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Electric vehicle interconnects	● Allows EVs to utilize TOU pricing and provides load data to detect potential voltage issues.	○ Not supported	○ Not supported	○ Not supported	○ Not supported

Table 40 (continued)

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Detect unsafe field metering conditions	● Provides service condition information such as temperature and service quality that can be used to detect unsafe conditions such as hot sockets.	○ Current AMR systems do not provide temperature information	○ Current AMR systems do not provide temperature information	○ Current AMR systems do not provide temperature information	○ Not supported
Reliable methods for detecting energy theft	● AMI offers the platform that can be used to detect energy theft conditions.	◔ Limited capability	◔ Limited capability	○ Not supported	○ Not supported

Legend for Capabilities				
Full	**Most**	**Partial**	**Minimal**	**None**
●	◕	◑	◔	○

As shown in this table, none of the other metering options come close to matching the capabilities provided by AMI. Moreover, these meter alternatives does not provide the same quantifiable and non-quantifiable benefits that I outlined above.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THE DIFFERENT AMR ALTERNATIVES?

A. While the AMR alternatives performing similarly to AMI in terms of basic meter reading capabilities, they cannot match the advanced TOU information, two-way capabilities, or functions provided by AMI. As the distribution system evolves with increasing amounts of DER, and customers' expectations require timely energy usage data and the ability to connect their smart devices to their meter, we must have the facilities to meet these needs. AMI is the correct technology to meet both our current and our future system and customer needs. The industry has also recognized the superiority of the AMI technology and vendors and suppliers of AMR systems and replacement parts are becoming harder to find.

Q. WHY DID THE COMPANY REJECT THE OPTION OF REVERTING TO DRIVE-BY AMR METERS?

A. Of the three types of AMR solutions, the drive-by solution is the most antiquated because such meters cannot be read remotely. Instead a drive-by AMR solution only provides meter readings when a meter reader drives by. Drive-by AMR meters would also have higher O&M costs as compared to AMI meters due to the need to perform drive-by meter readings which require additional personnel and fleet vehicles. For purposes of the CBA, the Company calculated the capital and O&M costs of a drive-by alternative. While these costs are lower than the costs for AMI, the drive-by system does not provide any of the benefits attributed to AMI as shown in Table 40 above.

d. Manual Read Meters

Q. WHY DID THE COMPANY REJECT THE OPTION OF REVERTING TO NON-AMR MANUAL READ METERS?

A. Reverting to manually read meters is not reasonable alternatives because reverting to non-AMR meters would require the replacement of well over a million meters but would not provide any of the benefits of the AMI meter such as timely energy usage data, outage information, or voltage information. In addition, manual read meters would have higher meter reading costs as compared to AMI meters due to the need to send personnel out into the field to perform manual monthly readings. Such manual meter reading is a less than ideal option as it would require hiring hundreds of meter readers along with the purchase of vehicles and equipment to perform these manual reads. Manual reading also has a lower read rate and an increase in the number of billing exceptions per read as compared to both AMR and AMI.

e. AMI Opt out

Q. WILL XCEL ENERGY OFFER INDIVIDUAL CUSTOMERS AN ALTERNATIVE TO AN AMI METER?

A. Yes. The Company will develop and offer customers the ability to opt out of having an AMI meter at the start of AMI deployment in 2021. This program will provide customers with the option to have a non-AMI digital meter installed and have it manually read on a monthly basis for billing purposes. This is discussed in further detail by Mr. Cardenas.

Q. WHAT DO YOU CONCLUDE ABOUT THE ALTERNATIVES TO AMI?

A. All of the variations of continuing the current outdated AMR technology provide limited benefits compared to AMI. AMI will provide customers more timely energy information and more control over how and when they use energy in their homes and businesses. It will enable the Company to provide an improved customer experience over AMR when addressing customers' concerns with their meter reading, billing, power outages, quality of service, and connections of service.

Further, AMI is much more than a meter reading technology; it is foundational component of overall AGIS initiative because it provides a central source of information with which many components of the advanced grid interact. For instance, AMI meters serve as important end of feeder sensors for IVVO and repeaters for the FAN communication network that increase the dependability of this network. The system visibility and data delivered by AMI provides customer benefits for reliability and enhances utility planning and operational capabilities. Although AMI offers many more customer benefits than AMR, our opt-out program plans will also provide customer choice for those who choose not to have an AMI meter installed.

7. Interoperability

Q. WHAT IS INTEROPERABILITY AND WHY IS IT AN IMPORTANT CONSIDERATION FOR THE COMPANY'S AGIS INVESTMENTS?

A. Interoperability is the ability for systems and different products from different vendors to work together seamlessly. For our AGIS investments, this means that each of the individual devices selected for this initiative will work together to perform the necessary task such as an on-demand meter reading.

Q. WHY IS INTEROPERABILITY AN IMPORTANT CHARACTERISTIC FOR THE AMI METERS?

A. Our AMI meters must be able to communicate and take direction from several different AGIS components, even if those components were manufactured by different vendors, as well as the Company's existing technology. For instance, since our AMI meters also serve as mesh network devices that transmit data from other field devices, it was important to ensure that the selected AMI meters had an interface that was capable of supporting multiple communication modules by multiple suppliers.

Q. HOW DOES THE AMI METER SELECTED BY THE COMPANY FACILITATE INTEROPERABILITY WITH THE OTHER AGIS COMPONENTS?

A. The Company's RFP that was issued to select the AMI meter vendor required the meter to have several interoperability characteristics. These included that the meter must be built to the industry ANSI C12 standard and have an interface capable of supporting multiple communication modules. The RFP process is discussed in greater detail above.

8. *Minimization of Risk of Obsolescence*

Q. WHAT STEPS DID THE COMPANY TAKE TO MINIMIZE THE RISK OF OBSOLESCENCE OF THE SELECTED AMI TECHNOLOGY?

A. One of the issues with new technology is that it is ever changing and new technology can be obsolete shortly after deployment. In evaluating different AMI technology, the Company put an emphasis on "future proofing" the capabilities to minimize the risk of obsolescence. Specifically, the Company sought and selected AMI technology that had the following characteristics:

- Over the air (OTA) firmware and meter configuration upgrades without field visits or meter replacement;
- Enhanced memory size to support potential future use cases that would require certain meter configurations;
- Flexible, standard service components that are common in the industry such that any future technology would be adapted to this industry standard;
- Architecture for ease of integration with existing and future systems; and
- Reduction in technology design and development costs due to the (re)use of standard interfaces.

Q. PLEASE EXPLAIN HOW THESE CHARACTERISTICS REDUCE THE RISK THAT THE SELECTED AMI TECHNOLOGY WILL BECOME OBSOLETE IN THE NEAR FUTURE?

A. We can predict that future needs will require our technologies to have more memory and better communications throughput. Among the possible changes are currently anticipated are advances in Distributed Intelligence, cybersecurity updates, and the ability to add more logic or intelligence in the meter. Based on this, the AMI meter specifications identified above will be essential in ensuring that hardware and technology deployed can be upgraded in the field without the need for a wholesale meter replacement.

E. FAN

1. *Overview of FAN*

Q. WHAT IS THE FAN?

A. The FAN is a private, Company-owned wireless communications network. The primary function of FAN is to enable secure and efficient two-way communication of information and data between our existing communication infrastructure located at our substations and new or planned intelligent field devices – up to and including meters at customers' homes and businesses. Through the substation infrastructure's connectivity to the Company's existing Wide Area Network (WAN), the FAN enables back-office applications to directly communicate with field devices providing usage information for both our customers and the Company.

The implementation of FAN is a joint effort with Business Systems, and Mr. Harkness provides detailed discussion of FAN and addresses the IDP filing requirements related to FAN in his testimony.

Q. WHAT ARE THE PRINCIPAL TECHNOLOGIES THAT WILL BE USED BY THE FAN?

A. To provide communication between the substation and field devices, the FAN will use two wireless technologies: (1) Wireless Smart Utility Network (WiSUN) mesh network; and (2) a Worldwide Interoperability for Microwave Access (WiMAX) network.

Q. WHAT IS THE PURPOSE OF THE WISUN AND WIMAX NETWORK?

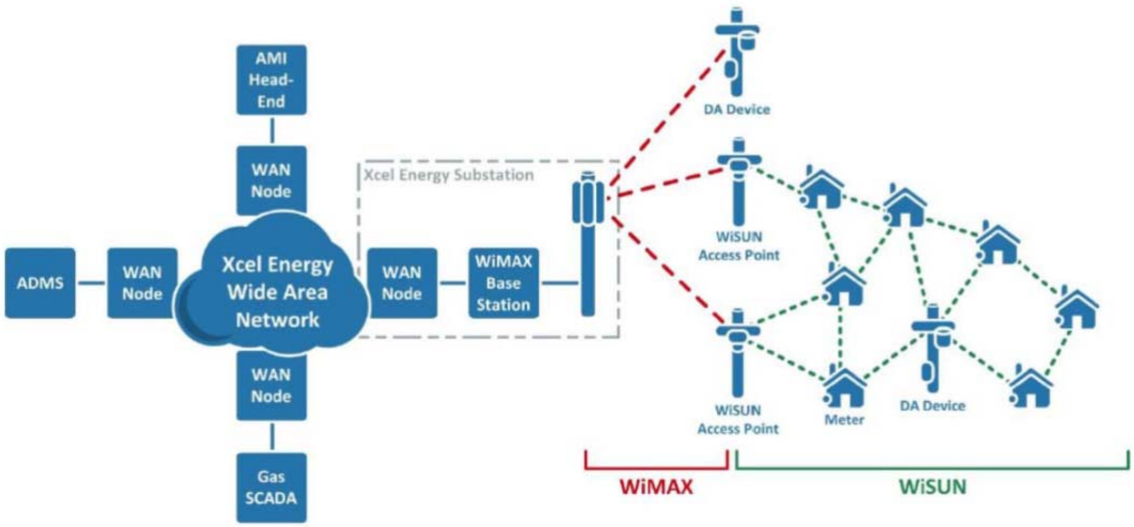
A. The WiSUN mesh network will communicate directly with the AMI infrastructure (including the advanced meters) and the Distribution Automation (DA) field devices used for IVVO and FLISR.

The WiMAX network will provide redundant, reliable, and secure connectivity between the WiSUN network and the Company's WAN. The field devices and the WiSUN access points connect to the WiMAX base stations (mostly located at the Company's substations) via wireless communication modules that are integrated into these devices.

Through the substation's connectivity to the WAN, the FAN (including the WiMAX network and the downstream WiSUN mesh network (will enable the Company's advanced applications (such as ADMS and AMI, and the sub-applications including FLISR and IVVO) to communicate with the field devices that implement those applications and sub-applications. Figure 11 provides an illustration of the principal components of the FAN. The WiSUN and WiMAX technologies are discussed in more detail by Mr. Harkness.

Figure 11

FAN Overview



Q. DESCRIBE THE COMPONENTS OF THE WISUN NETWORK.

A. The WiSUN mesh network is the key network structure that will communicate directly with the AMI infrastructure and most DA field devices. The core infrastructure for WiSUN will consists of three main device types:

- *Access Points*: device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network – WiMAX, in this case) to pass data between the mesh network and the WAN. The access points will be located primarily on distribution poles and other similar structures.
- *Repeaters*: are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide

devices more options to communicate with their access point. Repeaters will be located primarily on distribution poles.

- *Endpoint Devices*: include AMI meters and DA field devices, such as the intelligent FLISR and IVVO field devices, that have built-in radios. The AMI meters will be located on customer premises; the field devices will be co-located with either pole-mounted or pad-mounted distribution devices.

Q. DESCRIBE THE COMPONENTS OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations; and (2) customer premise equipment (CPE).[14]

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station with up to three radios that will communicate with the WAN and multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures.

The CPEs will further enable the back office applications to communicate wirelessly with any device accessible to that access point's connections to the mesh network. CPEs will be mounted on distribution poles in the field of operation.

[14] CPE is an industry term that refers to specific equipment. The "customer" in CPE refers to Xcel Energy or a similarly situated entity using this equipment and does not refer to Xcel Energy's customers.

Q. HOW WILL THE FAN DEVICES OPERATE IN THE EVENT OF A POWER OUTAGE?

A. The core infrastructure on both WiSUN and WiMAX is backed up by batteries to enable continued functionality and operations in the case of a power failure to that device – a situation where the continued functionality of those networks is critical. These battery systems also self-monitor and will automatically report any issues to ensure prompt repair. Specific devices will also have battery power, either supplied by the device itself or through a supplemental battery system, to enable continued operations during an outage. For example, the FLISR devices, that are critical during a distribution outage, will have battery power.

Q. HOW DOES THE FAN ASSIST THE OTHER AGIS COMPONENTS IN MANAGING OUTAGES?

A. As discussed above, the core infrastructure of both WiMAX and WiSUN will have battery backup as will other devices that are critical for outage operations. This means that the Distribution Control Center will still have visibility into the current status of the grid and remote control capabilities for devices like reclosers. Although AMI meters will not have battery backup, they will have energy storage adequate to send "last gasp" messages (that is, a final message transmitted by the meter upon detection of an outage) over the FAN to let the head-end system know that particular customers do not have power service. Once those customers have been reenergized, those meters will once again be able to communicate on the FAN and the head-end system will be able to remotely verify that customers have been reconnected. The additional visibility will also aid with the restoration of nested outages[15] by showing that certain customers remain without power even when the

[15] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

surrounding issue was resolved. This will help the control center identify those situations and reduce restoration times.

2. FAN Implementation

Q. WHAT WORK WILL DISTRIBUTION PERFORM TO SUPPORT INSTALLATION OF THE FAN?

A. The implementation of the FAN will be a joint effort between Business Systems and Distribution. Distribution will be responsible for the installation of the FAN devices (primarily access points, repeaters, and CPEs) that will be located on distribution poles. Distribution will also be responsible for installation of the WiMAX base stations. Business Systems will be responsible for installation of WiMAX base stations at the substations. Business Systems will also be responsible for the design of the network systems for WiMAX and WiSUN, the security of these networks, and configuring the software and hardware components of FAN.

Q. HOW WILL THESE FAN DEVICES BE INSTALLED BY DISTRIBUTION?

A. The access points, repeaters, and CPEs will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device and Distribution will be responsible for completing this modification or replacement. In areas where Xcel Energy has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

Q. HAS THE COMPANY ALREADY DEPLOYED FAN DEVICES IN MINNESOTA?

A. To support the TOU pilot, the Company deployed limited FAN infrastructure in 2019 in the small geographic area overlaying the AMI meter deployment (Eden Prairie and Minneapolis). Business Systems has begun to deploy WiMAX base stations in three substations and Distribution has begun to deploy of access points (APs) and repeaters that will be connected to those base stations.

Q. WHAT IS THE FAN IMPLEMENTATION SCHEDULE TO SUPPORT THE FULL AMI DEPLOYMENT STARTING IN 2021?

A. For any given geography, FAN availability will precede AMI meter deployment by approximately 3-6 months, to ensure that meters will have a fully operational network to use when they are installed. To support this, we will need to begin FAN installation approximately 12-18 months ahead of AMI meter deployment to allow adequate time for permitting, material sourcing, and construction. Based on the current schedule for the full AMI meter deployment, we anticipate FAN deployment will begin in mid-2020 to ensure network readiness for when AMI meters

3. FAN Costs

Q. WHAT DISTRIBUTION CAPITAL AND O&M COSTS ARE NECESSARY FOR FAN IMPLEMENTATION IN 2020, 2021, AND 2022?

A. As discussed above, the work that Distribution will be performing to support the implementation of FAN is limited to the procurement and installation of pole-mounted FAN devices. Mr. Harkness discusses Business Systems' FAN costs which include the costs for the WiSUN and WiMAX components. Tables 41 and 42 below provide Distribution's capital additions and O&M

costs for FAN implementation for 2020 through 2022 and I will describe these costs in further detail below.

Table 41

FAN Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FAN	$2.8	$5.4	$0.0

Table 42

FAN O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FAN	$0.1	$0.2	$0.4

a. Distribution's Capital Costs

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S FAN CAPITAL FORECAST?

A. These capital costs include FAN devices, installation, and project management, as well as preparation costs.

Q. HOW DID DISTRIBUTION DEVELOP THESE CAPITAL COST ESTIMATES FOR FAN?

A. To estimate the device costs and installation costs for FAN, Engineering performed a preliminary Radio Frequency Network Study. The purpose of this study was to determine the location and number of access points, repeaters, and CPEs that would be required to facilitate a reliable FAN communication network for the AMI meter and the distribution automation devices. The study concluded that approximately 550 access points, 3,000 repeaters, and 2,500 CPEs will be required for the FAN coverage area.

Q. WHAT WAS THE NEXT STEP IN DEVELOPING THE CAPITAL COST ESTIMATES?

A. After determining the number of devices, the price for each device was derived from prices included in contracts that resulted from several RFP processes. These RFPs are described by Mr. Harkness. The labor costs to install each device are based on a combination of contractor and internal labor.

Q. HOW DID DISTRIBUTION DETERMINE THE LABOR COSTS FOR THE INSTALLATION OF THE FAN DEVICES?

A. Our labor estimates are based on our prior experience with installing FAN devices for both FAN rollout in Colorado and the limited deployment of FAN in Minnesota to support the TOU pilot. This work provides a reasonable point of reference for the labor estimates for the FAN deployment in Minnesota.

b. Distribution's O&M Costs

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S O&M COSTS FOR FAN?

A. The FAN's O&M costs will include costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both Company employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

Q. HOW DID DISTRIBUTION DETERMINE THE O&M COSTS FOR FAN?

A. The projected costs associated with project employees are based on typical Company wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

c. Distribution Contingency for FAN

Q. DOES DISTRIBUTION'S FAN FORECAST INCLUDE CONTINGENCY AMOUNTS?

A. No. There is no contingency amount included in Distribution's FAN costs because Distribution has limited scope of defined work related to FAN.

d. FAN Expenditures 2020 to 2029

Q. WHAT ARE THE DISTRIBUTION'S CAPITAL EXPENDITURE AND O&M FORECASTS FOR THE FAN FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M forecasts for the FAN for 2020 through 2029.

Table 43

FAN Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FAN	$3.2	$6.2	$0.0	$0.0	$0.0

Table 44

FAN O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FAN	$0.1	$0.2	$0.4	$0.3	$0.4

F. FLISR

1. Overview of FLISR

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) 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. WHAT ARE FAULTS ON THE DISTRIBUTION SYSTEM?

A. Faults are failures of the electrical system, which result in abnormal power flows. The distribution system is designed to detect such conditions and de-energize the affected portions of the system in order to limit damage and ensure safety. Faults can be either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (i.e., greater than five minutes) is experienced by the customer. Permanent faults may be the result of insulator failures, broken wires, equipment failure (e.g., cable failure, transformer failure), and public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption (i.e., less than five minutes). Causes of temporary faults are transient in nature. Some examples are lightning, conductors slapping in the wind, animal contact, and tree branches that fall across conductors and then fall or burn off.

Q. HOW DOES XCEL ENERGY CURRENTLY IDENTIFY AND ISOLATE FAULTS ON THE DISTRIBUTION SYSTEM?

A. The Company does have a SCADA system that informs operators of most feeder and substation-level outages. When the outage does not impact a full feeder or where SCADA capability does not yet exist (many rural systems), Xcel Energy must rely on calls from customers to inform the Company of an outage. As customers call to report outages, the service locations are identified in our Outage Management System (OMS). Initially, each outage is identified as affecting a single customer. But as outages for customers served by common elements accumulate, the outage "escalates", and points to the most probable location for us to initiate our repair activities. The Control Center Operator then uses aggregated information from all current outages, prioritizes, and dispatches field personnel to effect the most efficient restoration. When dispatched, crews patrol the feeder to identify the cause of the fault then proceed to manually open switches to isolate the fault. Next, they manually close other switches to restore service to as many customers as possible. Finally, they affect the repairs and restore power to the customers.

Q. WHAT IS OUTAGE TIME FOR A TYPICAL FEEDER-LEVEL FAULT?

A. The average time to restore a feeder-level fault in Minnesota has been 124.9 minutes (5-year average, not storm-normalized). NSPM feeders serve, on average, 1,219 customers. The average customer count for the feeders selected for the proposed FLISR deployment is 1,687.

Q. ARE THERE DEVICES ON THE XCEL ENERGY SYSTEM THAT CURRENTLY ASSIST WITH FAULT ISOLATION AND SERVICE RESTORATION?

A. Yes. We currently have small-scale automation programs across our distribution system. We have been installing intelligent switches for a number of years on much of our 34.5 kV system in Minnesota. Like FLISR, these devices act to isolate the faulted section of the system and restore power to unfaulted sections of the feeder when possible. These intelligent switches have improved the reliability for over 114,000 Minnesota customers. If the device is successful at isolating the fault to one portion of the line, customers upstream of the device are spared from a sustained outage.

We have also been installing faulted circuit indicators, powerline sensors, and replacing certain relays on the system to aid our ability to quickly find a fault so we can begin restoring service to interrupted customers.

Q. WHAT ARE THE LIMITATIONS OF THE THESE EXISTING DEVICES?

A. While the existing sensing devices provide important benefits, they are not as flexible as the fault location devices that are now available. For instance, faulted circuit indicators do not provide the fault magnitude, which ADMS can use to locate the probable location of the fault. Also, many of the earlier systems rely on proprietary communications systems, which means they lack the ability to communicate seamlessly with other devices on our system. While these early intelligence devices have been beneficial for our customers and our operations, we intend to implement newer FLISR technologies going forward – eventually replacing some of the current devices.

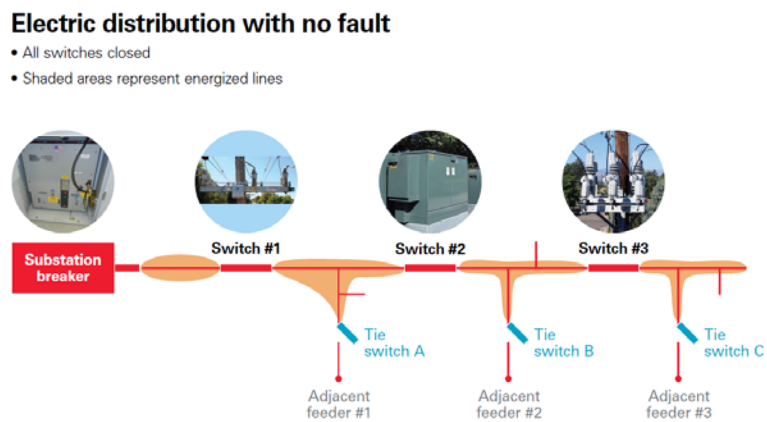
Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR OPERATES?

A. Yes. There are three basic steps to the operation of FLISR. First, the system identifies the faulted section and, where possible, calculates the probable location within that section. Second, the system isolates the fault by opening devices in the field. Finally, the system restores the service to as many customers as possible through additional automated field switching.

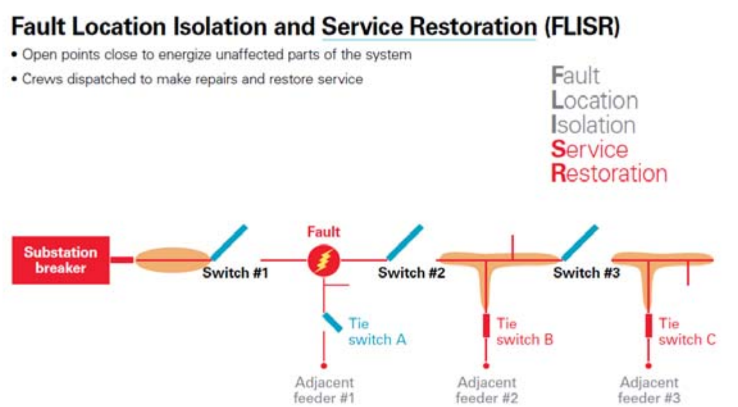
In the first step, when a fault occurs, the FLISR protective devices will open, or sectionalize the feeder to isolate the fault. Depending on the devices and the situation, the device may attempt to reenergize the affected area first, in case the fault was only temporary in nature. Once the fault is cleared (de-energized), data will be sent from those intelligent field devices to ADMS. ADMS will then run the FLISR application which will analyze the situation, select appropriate switching device near the fault, and generate a switching plan to restore service to other customers. In doing so, ADMS will take into account not only device and feeder loading, but surrounding 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 manually investigate the fault event. This process is expected to take less than five minutes from the occurrence of an outage to operator notification. ADMS will also be able to run the FLP algorithm and predict which segment within a FLISR section the fault exists, which will reduce expected patrol times by crews. Figure 12 below shows how FLISR isolates that impacted feeder section to restore power to other sections of the line.

Figure 12

FLISR Feeder Configuration – Prior to Fault



FLISR Feeder Configuration – Service Restored



Q. HOW WILL FLISR IMPACT THE COMPANY'S RELIABILITY PERFORMANCE?

A. We expect that FLISR will improve our overall reliability performance and a customer's overall outage experience. However, our performance in certain reliability metrics may decline after FLISR is installed. For instance, FLISR will help some customers avoid sustained outages. Sustained outages are tracked by the SAIFI metric (annual average number of sustained service interruptions per customer served) and shorter duration outages (less than five minutes) are tracked by the Momentary Average Interruption Frequency Index (MAIFI) metric. In essence, we expect that FLISR will transform outages that would have been sustained outages into momentary outages. In addition, with AMI meters, we will be better able to track these momentary outages for all of our customers.

As a result, with FLISR, we expect that customers will experience fewer sustained outages thus improving our SAIFI performance while our MAIFI performance will decline. We also expect that FLISR will cause our Customer Average Interruption Duration Index (CAIDI) performance to decline. CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. CAIDI performance declines when the outages are more heavily concentrated on problems that take a longer time to fix. As FLISR's automatic switching will restore power quickly to customers not along the faulted section, the result will be a sustained outage that impacts fewer customers. This will negatively impact our CAIDI performance but will be a more positive outage experience for our customers because FLISR will minimize widespread extended outages on the system.

Q. PLEASE DESCRIBE HOW FLP OPERATES AND HOW IT WILL IMPROVE CUSTOMERS' OUTAGE EXPERIENCES.

A. Feeders enabled only with FLP will operate in a slightly different manner from FLISR-enabled feeders. Should a fault occur, FLP devices upstream of the fault will capture an event occurring and will communicate relevant measurements pertaining to the fault (such as current, voltage, and phase indication) to ADMS. ADMS will compare these measurements to the impedance model and will generate expected fault locations. ADMS will then notify the operator of these locations (with a level of certainty for each location), and the operator will dispatch a crew directly to the expected faulted section (as opposed to having the patrol the entire feeder line, as in the current situation) to isolate the faulted section. This reduction in patrol time will result in reduced outage durations for our customers.

Xcel Energy is proposing to install up to two sets of three-phase advanced powerline sensors along each feeder targeted for FLP deployment. At the substation where the feeder originates, we will use either an intelligent relay or install one set of sensors. Existing remote fault indicators and new intelligent device telemetry will be incorporated into the FLP deployment. If an existing device is in the correct location to employ FLP functionality, this will obviate the need for a new device. Other existing devices will enhance FLP's capabilities by providing additional data to improve FLP algorithm performance.

Q. WHAT ARE THE COMPONENTS OF FLISR?

A. There are four principal components of FLISR:

- Reclosers;
- Automated overhead switches;
- Automated switch cabinets; and
- Substation Relaying.

There are two main components to FLP:

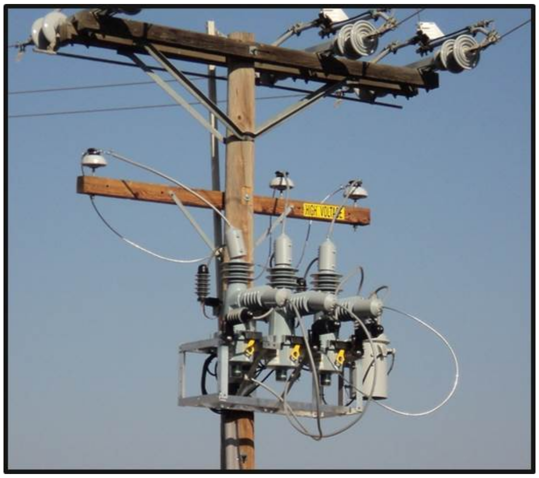
- Powerline sensors; and
- Substation Relaying.

Q. WHAT ARE RECLOSERS AND HOW DO THEY OPERATE?

A. Reclosers are pole-mounted reclosing and switching devices. The Company currently has reclosers on the distribution system, but only a few of these reclosers have communications to enable remote operations capabilities. The new devices employed by the Company will perform the same functions of existing reclosers but have enhanced monitoring, communications and control capabilities. The devices are able to identify and interrupt a fault event and then report the fault current to ADMS, which can then use that information to execute FLP to determine the location of the fault. The reclosers will be able to "re-close" after a fault event to determine if a fault still exists. If the fault does not persist, the recloser will reclose and restore service. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform the Company of the need to dispatch a crew to the fault location. In addition, the reclosers will be controlled by ADMS when there is a permanent fault to automatically restore service. Figure 13 is a picture of a recloser on a distribution pole.

Figure 13

Recloser on Distribution Pole



Q. WHAT IS AN AUTOMATED OVERHEAD SWITCH?

A. These switches are overhead remote supervisory sectionalizing and motor operated switching devices. When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault will sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches do not have the capability of reclosing to determine whether the fault is permanent in nature. Instead, overhead switches rely on the feeder breakers for the reclosing functionality. Although automated overhead switches lack the reclosing functionality, they are more compact and less expensive than reclosers, making them the preferred choice for space-constrained locations or where localized reclosing capability is not required.

Q. WHAT ARE AUTOMATED SWITCH CABINETS?

A. Automated switch cabinets are pad mounted sectionalizing and switching devices. Each cabinet has motor-operated, remote-controlled devices that the Company will use for switching underground feeders. They will perform functions similar to the automated overhead switches for our underground feeders. Each cabinet has two or more switches inside, providing the safe and reliable switching capabilities required for FLISR.

Q. WHAT IS THE FUNCTION OF THE POWERLINE SENSORS?

A. Powerline sensors are equipment placed on distribution lines to continuously monitor the grid and send information back to the utility for analysis and response. Sensors are available to measure such attributes as current, voltage, power factor, and faults. Specifically for FLISR, this technology will allow Xcel Energy the ability to detect disturbances on the grid and use this information to identify fault locations, isolate faults, and analyze the unique patterns of these events to predict the likelihood of future outages. Finally, we hope to leverage the equipment in the future to detect defective equipment before it fails.

Q. WHAT IS THE FUNCTION OF THE SUBSTATION RELAYS?

A. Substation-based relays, historically referred to as the feeder's overcurrent relays, provide the logic for when and why a breaker opens. The purpose of these relays is to monitor and, if warranted, to initiate commands to the feeder breaker to de-energize systems which have been compromised. This is to protect the public, utility personnel, and to minimize damage to public or private property or utility equipment. Modern relays are multi-functional and have multiple protection functions programmed into them. These relays can also capture important fault information which will be sent to ADMS for the fault location application.

Q. WHAT IS THE SERVICE LIFE OF THESE FLISR DEVICES?

A. The service life of each of the FLISR devices is 20 years for depreciation purposes.

2. *Prior Certification Request for FLISR*

Q. HAS THE COMPANY PREVIOUSLY BROUGHT FLISR FORWARD FOR COMMISSION APPROVAL?

A. Yes. The Company previously sought certification of FLISR under the Grid Modernization Statute[16] in its 2017 Biennial Grid Modernization Report.[17]

Q. WHAT ACTION DID THE COMMISSION TAKE ON THIS CERTIFICATION REQUEST?

A. The Commission denied this certification request without prejudice finding that the Company "had not fully demonstrated that FLISR is 'necessary to modernize the transmission and distribution system by enhancing reliability…" as required by the Grid Modernization Statute.[18] The Commission also found that the Company's cost calculations "emphasize the value of reliability but do not adequately assess that value and do not quantify estimated cost savings to ratepayers."[19]

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[16] Minn. Stat. § 216B.2425.

[17] *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).

[18] *In the Matter of Xcel Energy's 2017 Biennial Distribution Grid Modernization*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST at 7, (Aug. 7, 2018).

[19] *Id.*

Q. HOW DOES THE COMPANY'S CURRENT FLISR PROPOSAL DIFFER FROM THE ONE THAT THE COMPANY SOUGHT APPROVAL FOR IN 2017?

A. Our FLISR proposal is slightly revised from that proposed in 2017 in our Grid Modernization Report. We revised our plan with the insights gained from the deployment of FLISR devices in PSCo, resulting in a slightly smaller footprint. The current FLISR proposal will cover 208 feeders, serving 267,182 customers, and require 655 devices (switches and reclosers). This is slightly smaller than the previous proposal which was slated to cover 238 feeders, 290,122 customers, and require 809 switches and reclosers. The reason for the change is that we now have a better understanding of the labor and material costs for the installations and integration of FLISR into ADMS which was gained from our PSCo deployment. Even with this slightly reduced footprint, the benefits of FLISR remain strong and FLISR is a cost-effective way to improve system reliability.

Q. DID THE COMPANY ADDRESS THE COMMISSION'S OTHER CONCERNS RELATED THE RELIABILITY BENEFITS OF FLISR AND THE QUANTIFICATION OF THE COST SAVINGS TO RATEPAYERS?

A. Yes. As described in greater detail below and by Dr. Duggirala, the Company has prepared a comprehensive CBA for each of the AGIS components, including FLISR. This CBA quantifies the reliability benefits for our customers that will result from implementation of FLISR and compares those benefits to the cost of the FLISR investment. As discussed by Dr. Duggirala, the benefits of FLISR are expected to exceed the cost of FLISR, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

3. Interrelation of FLISR with other AGIS Components

Q. HOW DOES FLISR INTERACT WITH THE OTHER AGIS COMPONENTS?

A. In addition to its own intelligent field devices, the FLISR application relies on two primary elements to operate: (1) ADMS, for the central control and logic; and (2) the FAN, for wireless communications to each device.

Q. HOW WILL FLISR AND THE SENSING DEVICES INTERACT WITH ADMS?

A. ADMS will maintain an impedance model of the NSP distribution system. Real-time current, voltage, and status data will be used to run load flow and state estimation applications on that model, providing awareness of system conditions for that feeder and surrounding feeders.

ADMS will provide for remote monitoring and control of FLISR and FLP devices. When a fault occurs on a FLISR or FLP-enabled feeder, any device that senses the fault will send a signal to ADMS, notifying the system of the event. Devices that are capable will also send fault current magnitude during the event. ADMS will use both sets of data, comparing fault current data against the impedance model to generate an expected fault location. If that feeder is FLISR-enabled, ADMS will generate a switching plan to isolate the faulted section based on system conditions, and will issue commands to field devices on the feeder and adjacent feeders so that non-faulted sections can be automatically restored.

Q. HOW WILL FLISR INTERACT WITH FAN?

A. FAN enables the communication that allows the FLISR field devices to communicate with ADMS and their head-end systems. Specifically, the WiMAX system of the FAN which will be used by the FLISR switches is the backbone of the same system proposed to communicate with AMI and with IVVO devices.

Q. WILL FLISR AND FLP MAKE USE OF AMI METERS?

A. Yes, indirectly. FLP considers outage prediction results from a separate outage prediction application in situations where multiple possible fault locations are indicated. The outage prediction application utilizes data from AMI meters. In this way, FLISR and FLP indirectly use AMI data when determining the location of an outage.

Q. HOW WILL FLISR INTERACT WITH IVVO?

A. Both IVVO and FLISR require ADMS to make accurate power flow calculations. ADMS will consume and use information from all the types of sensors on the system. Thus, where IVVO's capacitors provide powerline sensing, FLISR will benefit from this data. Similarly, IVVO calculations benefit from the data provided by FLISR's reclosers. Further, as more data is provided to ADMS by both FLISR and IVVO devices, this information will enhance the ADMS system model, creating greater benefits for both FLISR and IVVO as well as other applications.

4. FLISR Implementation

Q. WHAT IS THE DEPLOYMENT STRATEGY FOR FLISR?

A. The deployment strategy for FLISR is a selective, targeted deployment. In general, we plan to target areas for FLISR where the electric system is predominately overhead, has high customer density, and has a history of outages that is more frequent than the rest of the distribution system. There are two primary criteria that drove our FLISR feeder selection, both of which are based on historic reliability information: (1) feeder SAIDI performance; and (2) the combination of the number of feeder mainline outages and the number of customers impacted over a period of time.

Q. WERE THERE OTHER CONSIDERATIONS IN THE DEVELOPMENT OF THE DEPLOYMENT STRATEGY FOR FLISR

A. Yes, FLISR, like other advanced grid applications requires communications capabilities to each sensor and switching device. For Xcel Energy, this communications platform is the FAN. As a result, the FLISR implementation must be completed in concert with the FAN implementation.

Q. WHERE WILL FLISR FIRST BE DEPLOYED IN MINNESOTA?

A. FLISR will be deployed to a small two-feeder area in South Minneapolis in 2020 to validate the ADMS capabilities. Nearly 4,400 customers will benefit from the new capability. The location overlays the TOU pilot geographic area, providing efficiencies to both of the projects thereby leveraging the initial, underlying FAN infrastructure.

Q. WHAT IS THE COMPANY'S APPROACH TO EXTENDING FLISR BEYOND THE AREA COVERED BY THE TOU PILOT?

A. The Company's approach is a balance between addressing the poorest performing feeders in terms of reliability and deploying the technology in a concentrated enough manner to allow it to be as effective as possible. Addressing the highest priority, poorest performing feeders first provides the greatest benefit for our customers as measured by a reduction in "customer minutes out of power" or CMO. As this project progresses through its 10-year deployment, we will continue to deploy FLISR using this prioritization method. Since feeder performance varies from year to year, it is expected that some adjustments to the initial deployment plan may occur, while keeping with the concept of maximizing the reliability value of the investment.

However, because FLISR relies on ties to adjacent feeders, the application is most effective and can have the largest impact on reliability and operations when deployed on multiple distribution feeders in the same geographic area. This concentrated deployment allows for normally open tie switches to be shared between two automated feeders, thus reducing the cost of deployment and also increasing operational flexibility.

Therefore, the deployment plan we propose for Minnesota is focused around deploying in this concentrated geographic approach – first identifying areas where a number of feeders have experienced the lowest levels of reliability over the past several years, and building out from there.

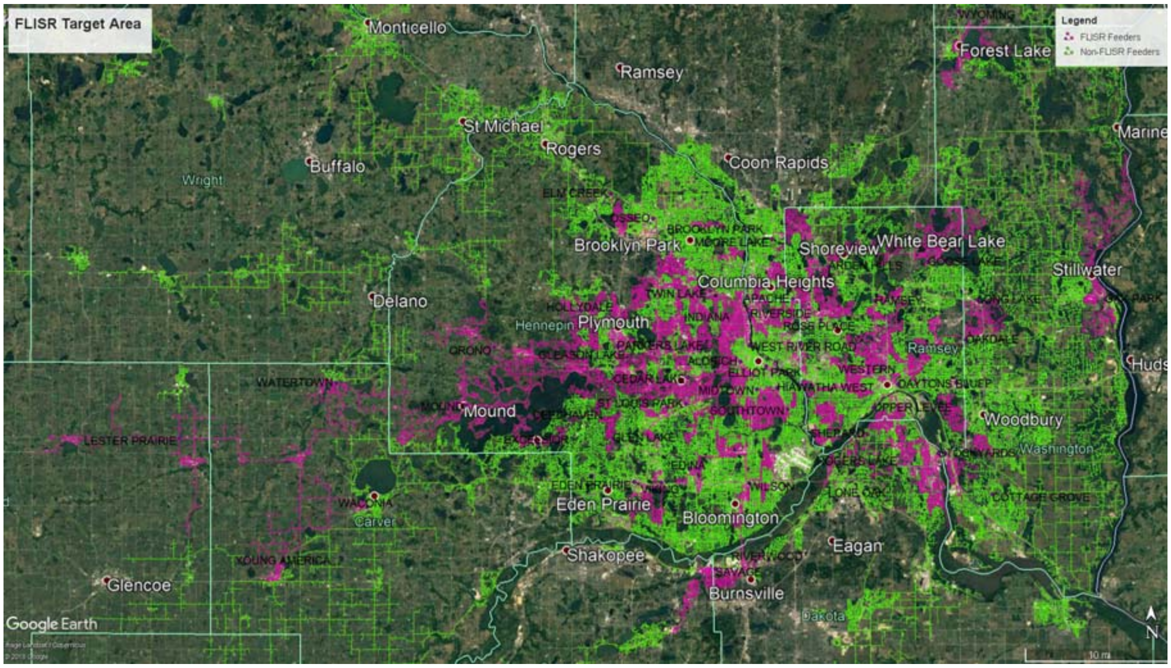
Q. HOW DID THE COMPANY DETERMINE THE FEEDER LOCATIONS FOR THE FLISR DEPLOYMENT?

A. The Company analyzed the reliability improvement potential for 980 feeders, and, when factoring in implementation and operational costs, developed a benefit/cost curve which was utilized to determine the size of the FLISR deployment. This deployment plan calls for the automation of 208 feeders in the greater Minneapolis/St. Paul metropolitan area, which provides potential for a 21.3 minute SAIDI reduction. For perspective, 208 feeders comprise about 27 percent of our metro feeders, which serve 40 percent our metro area customers.

Q. WHERE ARE THESE 208 FEEDERS LOCATED?

A. These selected feeders are located throughout the greater Minneapolis/St. Paul area and are shown in magenta in Figure 14 below.

Figure 14



Q. WILL FLISR BE DEPLOYED OUTSIDE OF THE GREATER METROPOLITAN AREA?

A. Over time, we expect to bring FLP (Fault Location Prediction) and full FLISR capabilities to additional areas as we continue to evaluate reliability and cost-effective solutions.

Q WHAT IS TIMING FOR THE DEPLOYMENT OF THE FLISR DEVICES?

A. We plan to deploy FLISR devices (reclosers, switches, and substation relays) at a relatively steady rate through 2028. The device installation rate is shown in Table 45 below. By the end of 2028, FLISR devices will be installed on 208 feeders, benefiting nearly 350,000 customers.

Table 45

FLISR Device Installation

FLISR Devices	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Field Devices	6	41	108	60	88	90	67	67	67	67	661
Feeders Impacted	2	13	34	19	28	28	21	21	21	21	208

5. Benefits of FLISR

Q. WHAT ARE THE BENEFITS OF IMPLEMENTING FLISR?

A. FLISR has both quantifiable benefits and non-quantifiable benefits. The most significant quantifiable benefit of FLISR is improved reliability for our customers, which we have estimated in two parts: (1) customer savings due to a reduction in CMO; and (2) patrol time savings due to the need to patrol a smaller portion of the system to find faults. These quantifiable benefits of FLISR were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratio for FLISR.

We also expect to achieve certain non-quantifiable 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 CUSTOMERS BEGIN SEEING BENEFITS OF FLISR?

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 is 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.

a. Quantifiable Benefits

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.

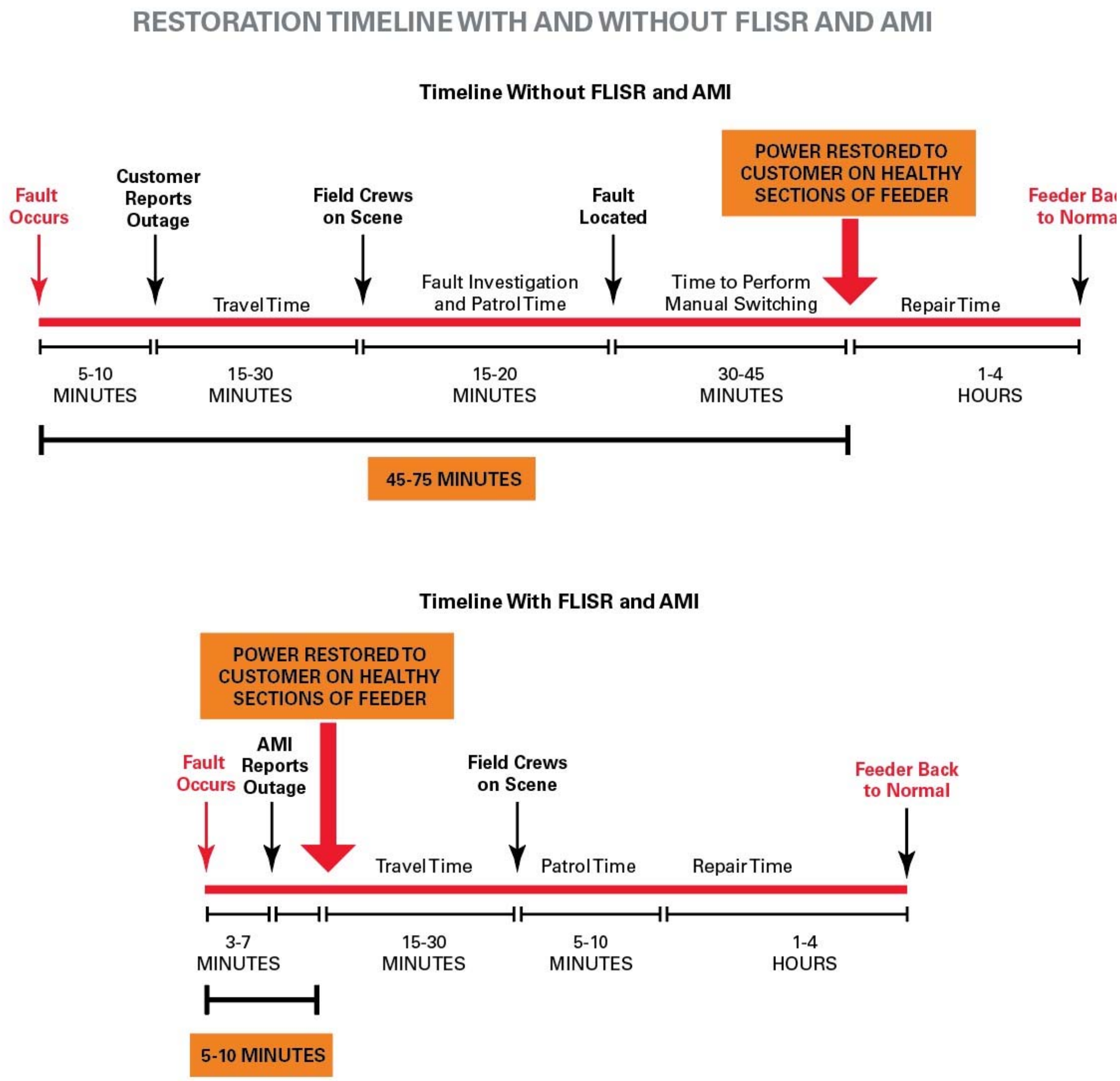
Restoration can be done manually or automatically within the system. Restoration considers not only device and feeder loading - but surrounding feeder and substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated 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 15 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 15



Q. HOW DID THE COMPANY QUANTIFY THESE RELIABILITY BENEFITS?

A. The Company quantified these reliability benefits in terms of: (1) customer benefit due to outage duration reductions and (2) reduced patrol time for crews to respond to outages. A summary of the calculations for these quantifiable FLISR benefits is provided in Exhibit___(KAB-1), Schedule 8.

(1) Customer Benefit of Reduced Outage Duration

Q. HOW DID THE COMPANY QUANTIFY THE VALUE ASSOCIATED WITH A REDUCTION IN THE DURATION OF A CUSTOMER'S DUE TO FLISR?

A. Sustained electric power outages and blackouts cost the United States approximately $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory (LBNL).[20] The automated restoration provided by FLISR will reduce CMOs for customers located on FLISR-enabled feeders. FLP will also reduce CMOs through more effective identification of fault events and improved dispatching of crews for restoration. To determine the value of this reduction in CMOs, Xcel Energy used the ICE Calculator developed by LBNL.

Q. HOW DID THE COMPANY UTILIZE THE ICE CALCULATOR TO VALUE A REDUCTION IN CMOS FOR ITS CUSTOMERS?

A. To calculate the value of a CMO, each FLISR feeder was divided into two classes, residential and commercial/industry, to determine the value lost during an outage. On average, the cost-per-CMO of a mainline outage for the proposed FLISR feeders is approximately $0.72. The Company then calculated anticipated benefits from FLISR using this cost-per-CMO.

Q. HOW DID THE COMPANY PERFORM THIS CALCULATION?

A. We performed studies on the historic SAIDI performance of each feeder to establish a baseline of reliability, using a rolling five-year average. We derived a cumulative CMO for each the FLISR feeders using actual reliability data over the 2010 to 2017 period. We calculated an annual average CMO for each of the feeders to compare to after FLISR is deployed.

[20] *Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers* (June 2018), available at: http://eta-publications.lbl.gov/sites/default/files/copi_26sept2018.pdf.

To quantify FLISR benefits, we applied the value for each CMO to the number of customers impacted by mainline feeder events – again using historic data. For the comparative future state once FLISR is deployed, we assumed that in a mainline fault event:

- All but one section of the customers on the feeder will see their power restored in less than one minute, which eliminates a sustained outage for the majority of customers on the feeder,
- An improvement of at least 50 percent from historic performance,
- Efficiencies associated with sharing tie switches between two automated feeders, such that each feeder acts as the back-up for the other, and
- A 25 percent reduction in the identified benefits, to represent a conservative but realistic estimate of the percentage of time that FLISR may not be available during an outage for some reason.[21]

The formula utilized to determine the annual CMO savings for each feeder is shown in Figure 16.

Figure 16

$$CMO\ Saved = (Average\ Annual\ CMO) * \frac{(Number\ of\ Sections - 1)}{Number\ of\ Sections} * (1 - Scale\ Factor)$$

[21] The system might not be available for switching for a variety of reasons, including communication failures or devices out of service for maintenance.

To determine the cost-per-CMO for a particular feeder, we divided the cost of the devices to automate that feeder with FLISR by the number of expected CMO saved to determine the cost-per-CMO saved.

(2) Outage Patrol Time Savings

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN OUTAGE RESPONSE TIME DUE TO FLISR?

A. A primary benefit of FLISR is the ability to see the real-time load across many critical points on the distribution system – and the ability to operate those devices remotely. Since FLISR and other remotely-controlled devices will allow us to identify and thus restore the root cause of an outage faster, our crews will be able to get to the next outage faster – increasing crew productivity and reducing the duration of each subsequent outage event from what it would have been without the increased system visibility. Once our system is widely automated, the cascading benefits from this will have a meaningful impact on reliability for all customers, whether they are on a FLISR feeder or not.

The Company estimates that FLISR will reduce the field time that crews spend responding to outages by an average of 10 minutes per outage. The actual time reduction will differ by situation. In some cases, damage reports will allow us to locate the problem immediately and the patrol time saving benefit from FLISR will be small. In many others, there will be substantial reduction of patrol time resulting from the ability to pin-point the fault location, which will focus our crews on either the calculated location or on a smaller portion of the feeder. This 10 minute reduction is our best estimate of the average savings due to the ability of FLISR to pinpoint the fault location.

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT ASSOCIATED WITH THIS REDUCTION IN THE FIELD TIME REQUIRED TO RESPOND TO AN OUTAGE?

A. The Company calculated the CMO saved through this improvement in patrol time, and using the ICE calculator, assigned a value.

b. Non-Quantifiable Benefits

Q. ARE THERE OTHER BENEFITS OF FLISR THAT THE COMPANY WAS UNABLE TO QUANTIFY?

A. Yes. One of the benefits that the Company was unable to quantify is the value of the data provided by FLISR for purposes of planning the system. 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.

6. FLISR Costs

Q. WHAT ARE DISTRIBUTION'S COSTS TO IMPLEMENT FLISR?

A. Distribution's principal costs of implementing FLISR are related to the costs for the FLISR devices and their installation. FLISR costs are broken down by capital additions and O&M costs through the term of multi-year rate plan in Tables 46 and 47 below. I will describe each of these costs in further detail below.

Table 46

FLISR Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FLISR	$3.1	$8.0	$5.8

Table 47

FLISR O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.1	$0.3	$0.2

a. Distribution's Capital Costs

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 in Colorado provide confirmation that these costs estimates are reasonable.

b. Distribution's O&M Costs

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.

c. Distribution Contingency for FLISR

Q. PLEASE DESCRIBE THE FLISR CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. Distribution's FLISR budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 12 percent. This smaller contingency percentage (compared to the contingency for AMI) is considered adequate because the cost projections for devices and installation were developed based on historical costs, and we believe we have fairly accurately estimated the quantity of equipment and cost of installation of the FLISR devices.

d. FLISR Expenditures 2020-2029

Q. WHAT ARE THE CAPITAL EXPENDITURE AND O&M FORECASTS FOR FLISR FOR DISTRIBUTION FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M related to FLISR through 2029.

Table 48

FLISR Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FLISR	$3.1	$8.1	$5.9	$16.0	$26.3

Table 49

FLISR O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FLISR	$0.1	$0.3	$0.2	$3.2	$2.4

7. *Alternatives to FLISR*

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; (2) implementing FLISR without the other AGIS components; and (3) delaying the deployment of FLISR.

Q. WHAT DID XCEL ENERGY CONCLUDE AFTER EVALUATING THE POSSIBILITY OF MAINTAINING THE CURRENT SYSTEM?

A. 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.

Q. DID THE COMPANY CONSIDER IMPLEMENTING FLISR BY ITSELF WITHOUT THE OTHER AGIS COMPONENTS?

A. Yes. We specifically considered installing FLISR without AMI. Such an installation was proposed by the Company in our 2017 Grid Modernization Report. However, as we pointed out in that filing, the FLISR application relies on three primary components to operate: (1) ADMS, for central logic and control; (2) FAN, for wireless communications to each device; and (3) FLISR field devices. As a result, even if FLISR is implemented without AMI, some portion of the FAN infrastructure would still need to be deployed to provide the necessary communication capabilities from the Company's back-office applications to each sensor and switching device. The FAN infrastructure required for FLISR is the same infrastructure that will support AMI and IVVO. Thus, while FLISR could be implemented as a standalone project with limited FAN deployment, there are efficiencies gained by deploying FLISR at the same time as AMI and IVVO as these programs require the same FAN communication infrastructure.

Q. DID THE COMPANY EVALUATE THE POSSIBILITY OF DELAYING THE DEPLOYMENT OF FLISR?

A. Yes. However, the Company determined that such a delay would only 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.

8. Interoperability

Q. HOW DOES THE COMPANY'S FLISR PROJECT ENSURE AND FACILITATE INTEROPERABILITY OF THIS TECHNOLOGY?

A. The Company plans to implement FLISR components that are vendor-neutral, non-proprietary, standards-based, and interoperable. This will allow the Company the ability to switch equipment vendors at any time and the new devices will be able to easily operate with the existing FLISR system and devices.

9. Minimization of Risk of Obsolescence

Q. HOW DOES THE COMPANY'S FLISR INVESTMENT PROTECT AGAINST OBSOLESCENCE?

A. Xcel Energy has always maintained an outlook that our assets must provide customer value over a long time period, a philosophy that has driven us to install quality equipment at the best price we can negotiate. That philosophy remains foundational to our goal of providing long-term value to our customers. Through our selection and sourcing procedures we select equipment from vendors which are well-established, financially viable, and show visionary leadership. While we cannot guarantee the longevity of any specific vendor, these attributes help to ensure the products will remain supported.

For electronic equipment, we specify equipment which can be remotely upgraded with new firmware as functionality or security needs dictate. Our requirement to leverage open standards is foundational to the concept that we will not become dependent on any single vendor, but that we will be free to integrate components from different vendors, should subsequent evaluations direct. In addition, we work closely with manufacturers to ensure they are building security into their equipment.

Specifically with FLISR, we have selected equipment and controls that adhere to these principles and are highly configurable. The recloser and switch controls, in particular, are sourced from industry leaders and can be used autonomously or in concert with the FLISR control system. The switches and reclosers themselves use state of the art, proven designs and technology.

G. IVVO

1. Overview of IVVO

Q. WHAT IS IVVO?

A. Integrated Volt-VAr Optimization, or IVVO, is an advanced application that automates and optimizes the voltage of the distribution system using equipment installed at the substation and along the feeder. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder to the tail-end via control of capacitors and other voltage regulating devices for voltage support. With IVVO, voltage can be monitored along the feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be lowered to achieve a variety of operational outcomes such as:

- Reduction of distribution electrical losses;
- Reduction of electrical demand;
- Reduction of energy consumption; and
- Increased ability to host DER.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS AS TO HOW IVVO WILL BE OPERATED?

A. The ADMS that we are in the process of implementing is capable of running the IVVO application in several different operating modes: Voltage Control, Peak Reduction, VAr Control, and Conservation Voltage Reduction (CVR).

- *Voltage Control mode* functions to optimize voltage on the feeder around standard operating voltages – maintaining adequate service voltage for all customers. This mode is generally a secondary operating mode of IVVO, and only used to establish the voltage boundaries within which the other operating modes must stay within. As penetration of DER grows, Voltage Control will become more common as a primary control mode to manage the expanded range of distribution system voltage caused by DER. Traditionally, with only load on a feeder, the Voltage Control objective was to raise voltage at times of heavy load in order for voltage to remain within the acceptable range. With DER causing reverse power flow and raising voltages during times of light loading, voltage control schemes must now both raise and lower voltage.

- *Peak Reduction mode* serves to reduce load only during peak load events. It is a manually triggered mode that reduces system voltage to a targeted value to reduce load on the system for a short duration – typically one or two hours. This peak reduction tool can be used in large operating regions, such as Minnesota as a whole, or tactically by feeder, substation, or other targeted area.
- *VAr Control mode* seeks to reduce system losses and save energy by optimizing power factor on each distribution feeder.
- *Conservation Voltage Reduction (CVR) mode* seeks to save energy through reduced operating voltages. CVR mode first flattens the load profile along the feeder using capacitors, and then uses the Load Tap Changer (LTC) or Voltage Regulators inside the substation to lower voltage on the feeder. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. WHAT ARE THE PHYSICAL COMPONENTS OF IVVO?

A. There are four principal utility equipment components of IVVO:

- Capacitors;
- Secondary static VAr compensators (SVC);
- Voltage and current sensing devices; and
- Load Tap Changers (LTC).

Q. WHAT ARE CAPACITORS AND WHY ARE THE NEEDED?

A. Electric loads like motors require two types of power to operate: active and reactive power. Distribution line capacitors provide local VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system. Capacitors are currently switched on and off using the SmartVAr program with a goal of improving power factor and reducing losses. With IVVO, these existing capacitor banks will continue to be used; however the control will be changed from SmartVAr to ADMS. We expect to add, on average, about half of a capacitor bank per feeder to the existing fleet to ensure proper IVVO performance. The Company plans to install 96 capacitors for this purpose.

Q. HOW DOES IVVO DIFFER FROM SMARTVAR?

A. The Company's legacy SmartVAr system currently controls 2,329 capacitor banks on 897 feeders within the NSPM footprint. This system is delivering good value by maintaining high power factor, which reduces distribution system losses. The IVVO program improves on SmartVAr by offering additional capabilities and control modes such as the CVR mode.

Q. WILL IVVO REPLACE THE SMARTVAR SYSTEM?

A. Ultimately, yes. As we enable IVVO, we will change control of 417 of these capacitors (on 189 feeders) from SmartVAr to ADMS to achieve the benefits of energy savings through reduced voltage. To consolidate control systems and enable the enhanced benefits ADMS has to offer, our plan is to move control from SmartVAr to ADMS for the remaining devices/feeders in the future.

Q. WHAT ARE SVCS AND WHY ARE THEY NEEDED?

A. The SVCs are electronic secondary capacitors that provide fast, variable voltage support to help stabilize and regulate the voltage. Each device is able to act in less than a cycle (a cycle is defined as 1/60 of a second since the United States AC frequency is 60 Hz), as opposed to a traditional utility capacitor device that operates on 60-90 second time delay. These devices provide dynamic voltage response for load, and are located closer to customers - or nearer the edge of the grid - than the Company's existing capacitors.

The devices' capabilities will enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and other intermittent distributed resources. The Company will strategically place approximately 270 SVC devices along feeders that need additional voltage support. In the event that IVVO function is limited by localized low voltage, SVCs are a tool that can readily be employed to improve IVVO performance, and thus its benefits.

Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING BOTH PRIMARY AND SECONDARY CONNECTED (SVC) CAPACITANCE.

A. Capacitance can be added either at the primary or secondary level. While the cost-per-kVAr is substantially less when applied on the primary level, applying it on the secondary level can alleviate localized low voltage and thereby increase the depth to which CVR mode can be operated. To that end, we have found deploying SVCs on select low voltage sites to be helpful. Applying this technology is optional, but has the potential to increase energy savings. We plan to analyze the feeders where IVVO is proposed and, if warranted, install these devices selectively to mitigate potential voltage issues. Once in operation, we will deploy additional units as warranted.

Q. HOW ARE THE SVCS CONTROLLED BY THE ADMS?

A. The aggregating software Grid Edge Management System (GEMS) will be used to communicate between the ADMS and the SVCs to achieve full value.

GEMS is a software application developed by Varentec to monitor and control Varentec's "Edge of Network Grid Optimization" (ENGO) devices. These all-in-one ENGO devices are used to control and improve customer voltages in conjunction with an IVVO scheme.

The Company will install these devices with FAN NICs which will allow these devices to communicate through the GEMS system. The benefits of communicating through GEMS are:

- Ability to change devices voltage setpoints;
- Provides ADMS with VAr and voltage data from ENGOs;
- Ability to update firmware;
- Ability to query devices for operational history; and
- Enable control to help validate benefits.

Q. DID THE COMPANY CONSIDER INSTALLING SVCS WITHOUT GEMS?

A. Yes. SVCs can be installed as stand-alone devices. However, without GEMS we would not have any insight into their operational data, we would not be aware of failures, and we would not be able to quantify their effect or benefit. Further through GEMS, SVCs provide voltage data to ADMS which helps ADMS make better decisions to optimize voltage.

Q. WHAT IS THE FUNCTION OF THE LOAD SENSING DEVICES?

A. IVVO requires end-of-line voltage sensing to monitor the voltage and ensure it is compliant with ANSI Standard C84.1. The Company intends to use the newly installed AMI meters as "bellwether" sensing devices to provide near real-time voltage sensing. When located at the edge of system (i.e., at the customer premise) where voltage is predictably lowest, these sensors will ensure that IVVO does not lower the voltage to the degree that customers would experience voltage below the acceptable standard. The plan is to configure, on average, 10 meters per feeder to provide this data. We will be able to reassign meters as bellwether meters as necessary should load or feeder topology change.

Q. WHAT IS THE FUNCTION OF THE LOAD TAP CHANGERS (LTC)?

A. This is equipment that is installed on the substation transformer to enable voltage regulation. Substation transformers equipped with LTCs provide voltage regulation by varying the transformer ratio or tap. LTCs typically have 16 taps above and below neutral (33 taps total) and each tap adjusts the transformer turns ratio by 0.375 percent. LTCs are currently monitored and locally controlled based on the local bus voltage. LTCs raise or lower the voltage by tapping up or down based on the settings of the local controller and the demand of the substation transformer. The LTCs themselves will be used, but the controls for some of the legacy units will be upgraded to allow ADMS to control the setpoints. As part of IVVO, we will upgrade nine of the 30 LTC controls to accomplish this. The new LTCs may also require substation Remote Terminal Unit (RTU) upgrades due to the increased SCADA data demands of new LTC controls and FLISR relays. We are budgeting to replace 7 RTUs as part of IVVO.

Q. WHAT IS THE FUNCTION OF THE PRIMARY POWERLINE SENSORS?

A. Primary powerline sensors measure current, voltage, power factor, fault magnitude, and other attributes. Primary powerline sensors are also capable of providing fault current data that is useful to FLISR and FLP in detecting the location of faults on the system.

Q. HOW WILL THE INFORMATION OBTAINED FROM THE POWERLINE SENSORS BE UTILIZED BY ADMS AND IVVO?

A. ADMS uses real-time data to fine-tune its system solutions. The primary input to this will be the feeder load and voltage information, normally delivered via SCADA from the RTU in the substation. ADMS will also use all additional data available from primary powerline sensors, meters at larger DER sites, and secondary meters at large customer locations. ADMS will use the measurements – power, reactive power, and voltage - to improve power flow calculation accuracy and display the measurements and results geospatially. Where possible, we will install new capacitors and switches with primary powerline sensors. Where existing capacitors and switches will not be replaced, we will strategically install stand-alone powerline sensors to provide the data required for ADMS.

Q. WHAT IS THE COMPANY'S INSTALLATION PLAN FOR THE POWERLINE SENSORS?

A. We plan to install 180 sets of sensors on the 189 feeders selected for IVVO to ensure that we have accurate load flow to operate IVVO. Taking into account the powerline sensors, sensors installed with new capacitor banks, and sensors at FLISR devices, there will be roughly two sensor points per feeder in addition to the feeder breaker.

2. *Interrelation of IVVO with other AGIS Components*

Q. HOW WILL IVVO INTERACT WITH ADMS?

A. IVVO will be an advanced application within ADMS. ADMS will operate as a centralized system that monitors inputs from devices such as substation RTUs, capacitor banks, AMI meters, LTCs, and other distribution automation devices. ADMS will take the inputs from these devices and compute the most efficient way for the system to operate and respond to changes. IVVO, through ADMS, will implement automated activities such as opening and closing of capacitors, and sending new settings to LTCs and SVCs. ADMS will also compute the most efficient way for the system to operate based on both manual switching and FLISR (e.g., for construction and maintenance activities and outages). The LTC control devices will take direction from ADMS, which will make decisions based on knowledge about the entire system, rather than only about voltage at the local bus. As a centralized system, ADMS will be able to control the distribution devices to work in unison and dynamically react to an increasingly complex system in a safe, efficient, and reliable manner.

Q. HOW WILL IVVO INTERACT WITH AMI?

A. AMI meters used as bellwether meters are the least cost method to provide voltage inputs to ADMS at key locations across the grid. For IVVO to be successfully and safely operated, voltage endpoints are necessary at 10 end points on each feeder; without AMI, this data would need to be gathered in other ways. Our preliminary analysis for Minnesota shows the use of voltage sensors would be approximately ten times the cost per unit of an AMI meter. Thus, the AMI initiative is a critical part of IVVO deployment to minimize the cost of providing end of line voltage data.

Q. HOW WILL IVVO INTERACT WITH THE FAN?

A. IVVO will leverage the FAN for communication with its field components, principally capacitors and static VAr compensators. The FAN will also support communications from distribution powerline sensors, necessary for

ADMS to calculate the power flows that are fundamental to IVVO operations. And as mentioned above, bellwether AMI meters will communicate via the FAN.

Q. HOW WILL IVVO INTERACT WITH FLISR?

A. First, IVVO and FLISR share the common need for accurate ADMS calculations. There is a mutual benefit when sensors installed on equipment necessary for FLISR (i.e., reclosers) and IVVO (i.e., capacitors) exist on the same feeders. The additional system inputs enhance ADMS accuracy.

Second, IVVO will react to system changes initiated by FLISR. When systems are reconfigured, the load may change significantly and the voltage controls must respond quickly. This capability exists within ADMS.

3. IVVO Implementation

Q. WHAT IS THE IMPLEMENTATION PLAN FOR IVVO?

A. The implementation plan for IVVO is a targeted, core deployment within the western Twin Cities metropolitan area which coincides with our initial ADMS deployment. This implementation will start in 2019 and continuing through 2024.

Q. WHERE AND WHEN WILL IVVO DEVICES BE DEPLOYED FIRST?

A. As part of the installation of ADMS, we plan to start by implementing IVVO on the seven-feeder system emanating from our Hiawatha West substation in Southeast Minneapolis. This system will support the testing of ADMS in the second quarter of 2020. The system's existing capacitors and LTC controls will be augmented with powerline sensors in late 2019 and early 2020 to enable this work. The Company will install approximately 35 SVCs, which will operate autonomously to provide localized voltage support.

Q. WHAT IS THE NEXT STEP IN THE CORE DEPLOYMENT OF IVVO?

A. Xcel Energy proposes to then implement IVVO at 13 substations (serving 224,000 customers). These 13 substations contain 30 transformers and serve 189 feeders. The Company will capture data and install and configure equipment, ensure the accuracy of the calculations, and then enable continuous IVVO functionality. IVVO will be enabled by substation transformer area (each substation contains 1-3 distribution transformers, and each transformer typically serves 4-7 feeders). This work will occur between 2021-2024, with these areas enabled roughly in a linear fashion beginning in 2022. The SVCs and controlling software (GEMS) would be deployed with IVVO. A detailed IVVO device implementation schedule is provided in the table below.

Table 50

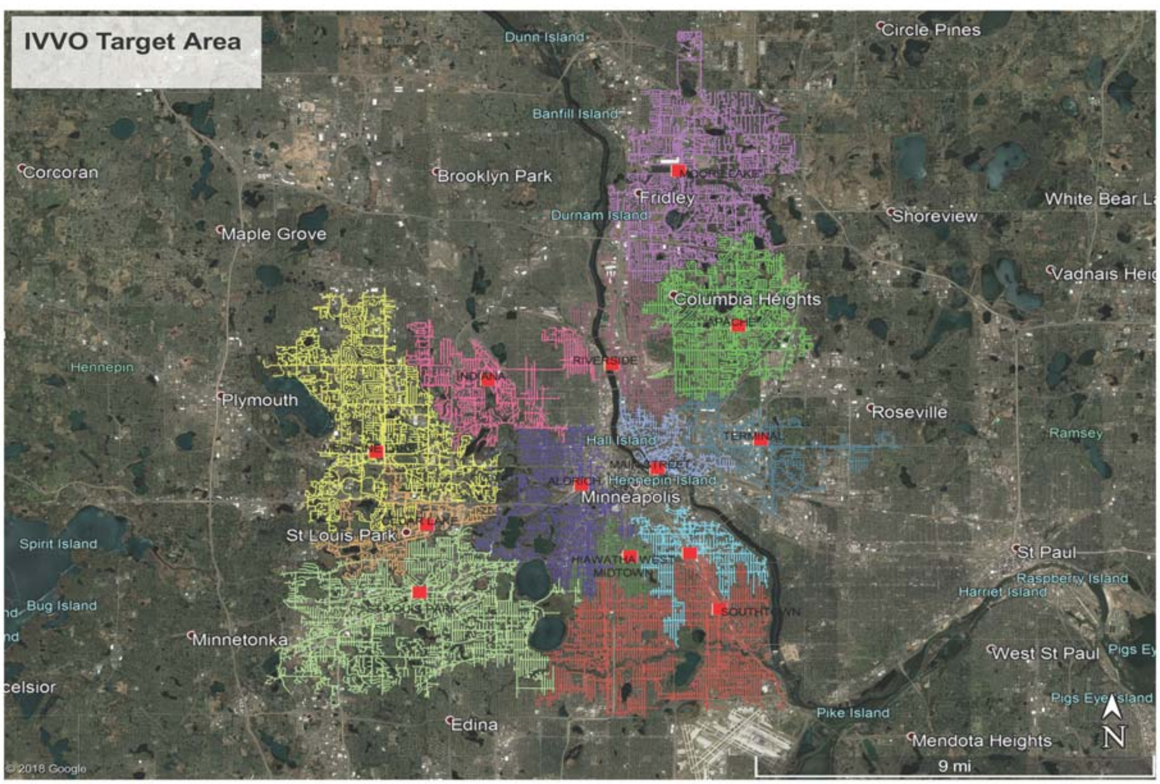
IVVO Device Implementation Schedule

VVO Devices	2019	2020	2021	2022	2023	2024	Total
Capacitors	0	0	16	32	23	25	96
ENGOS	35	0	35	82	82	71	270
Line Sensors	20	0	40	49	46	45	180
LTC Controls	0	0	1	3	3	1	8
Bellwether meters	0	0	0	945	945		1,890

Q. WHERE ARE THESE 13 SUBSTATIONS LOCATED?

A. These substations are located throughout the Minneapolis/St. Paul area and are depicted by the red circles on Figure 17 below.

Figure 17



Q. HOW DID XCEL ENERGY DETERMINE THE SCALE AND SCOPE FOR THE CORE DEPLOYMENT OF IVVO?

A. The Company sought to optimize the value, providing maximum energy savings while minimizing investment. To select the specific substations and feeders for this core deployment, the following factors influenced this selection:

- *ADMS overlay*. The Company chose to implement in the region controlled by our Metro West control center, which is the first control center to operate ADMS in Minnesota as part of the ADMS project.
- *LTC costs*. Because one LTC controller is required per transformer, and the Company uses larger power transformers in the metro area serving many feeders, the IVVO substation investment per customer is lowest in metropolitan area. Indeed, 22 of the 30 transformers chosen already had been equipped with the appropriate LTC controller. Similarly, the chosen substations generally had newer RTUs which support the functionality.
- *Customer Density*. The selected feeders are typical for urban and suburban feeders, having a slightly greater customer density than the average feeder.
- *Load Density*. The load density for the selected feeders is slightly lower than the system average. This lower density makes them good candidates for achieving a flattened voltage profile, which gives us a greater opportunity to achieve IVVO results. The Company is interested in observing how the adoption of EVs by customers served from these feeders affects the load density and IVVO.
- *Uniformity of feeder length*. IVVO benefits are generally restricted by the longest feeder served by each transformer. This is because longer

feeders have greater voltage drop and, without additional investments, this limits the potential reduction. The feeders in the core deployment area are generally of uniform length for each transformer area.

Q. WILL XCEL ENERGY EXPAND THE DEPLOYMENT OF IVVO TO OTHER AREAS OF ITS SYSTEM AFTER 2024?

A. As I noted, Xcel Energy has determined that a core deployment of IVVO within the Twin Cities metro area is the best first step that allows us to maximize the benefits of IVVO while testing the functionality of IVVO for broader deployment. As the Company learns more about the benefits and costs of IVVO from this core deployment, we will consider implementing IVVO more broadly in the future.

Q. WHEN WILL CUSTOMERS BEGIN SEEING BENEFITS OF IVVO?

A. Customers connected to feeders with IVVO will begin seeing benefits as soon as their substation transformer area is tuned and IVVO is implemented. Thus, the customers on the initial seven feeders will see benefits starting in 2020. Customers impacted by the subsequent deployment will see benefits starting between 2022 and 2024. Of course all our customers indirectly benefit from the lowered energy requirements due to the overall energy efficiency and demand reduction. As discussed later in my testimony, this reduction provides cost savings as well as environmental benefits.

4. Benefits of IVVO

Q. HAS XCEL ENERGY IDENTIFIED BENEFITS THAT WILL BE GAINED FROM DEPLOYING IVVO?

A. Yes. We have identified a range of benefits, both quantifiable and non-quantifiable. In terms of quantifiable benefits, these include reduction in energy consumption, reduced electric losses, and avoided capacity costs. These quantifiable benefits of IVVO were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratios for IVVO. I also describe qualitative benefits that were not quantified by the Company, but that will result from deployment of IVVO.

a. Quantifiable Benefits of IVVO

Q. CAN YOU PROVIDE A SUMMARY DESCRIPTION OF THE QUANTIFIABLE BENEFITS OF IMPLEMENTING THE IVVO TECHNOLOGY?

A. There are four areas of quantifiable benefits of IVVO:

- *Reduction of Energy Consumption*. Flattening the voltage profile along a feeder and operating in the lower range of 114V to 120V reduces energy consumption for certain devices, like incandescent lighting or motors such as those found in air conditioners, dryers, and refrigerators. Ensuring these types of devices are operated in the lower voltage range makes them more energy efficient. The industry term used to describe operating in the lower voltage range is CVR (Conservation Voltage Reduction). Studies have shown that the CVR benefit varies with the load type, climate zone, and feeder characteristics. The amount of energy efficiency or demand reduction that is achievable is highly dependent on a number of factors, including various attributes and the configuration of the distribution system, and customer attributes such as customer density, load characteristics, and the mix of residential and commercial customers.

- *Reduction of Distribution Electrical Losses.* IVVO models in ADMS can turn the capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on the distribution system. This improves the efficiency of the system, reduces system losses, slightly decreases energy generation needs, and reduces carbon emissions. Because power factor improvements have largely been achieved through our existing SmartVAr program in Minnesota, we expect this incremental benefit through IVVO to be modest.
- *Avoided Capacity Costs.* A by-product of reduced energy consumption is the corollary reduction of demand. By not having to provide that capacity, the benefit can be shown as a deferral of capital investments in generation, transmission, and distribution to serve peak demand.
- *Carbon Emissions Reduction.* Another by-product of reduced energy consumption is the corollary reduction in generation which in turn results in reduced CO_2 emissions. The Company valued this reduction in CO_2 emissions using Commission approved values.

I will discuss the first three benefits (reduction in consumption, losses, and avoided capacity) and Dr. Duggirala will discuss the last benefit (carbon emissions reduction). A summary of the calculations for all of the quantifiable IVVO benefits is provided in Exhibit___(KAB-1), Schedule 9.

(1) Energy Savings

Q. CAN YOU GENERALLY DESCRIBE HOW THE IMPLEMENTATION OF IVVO WILL RESULT IN ENERGY SAVINGS?

A. Customer's end-use devices are designed to operate over a range of voltages. Historically, the voltage on the distribution system is toward the high end of the range, which causes devices to consume more energy. IVVO when operated in CVR mode will allow the Company to lower the voltage on the feeder while still keeping it within acceptable limits. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW IVVO WILL RESULT IN ENERGY SAVINGS?

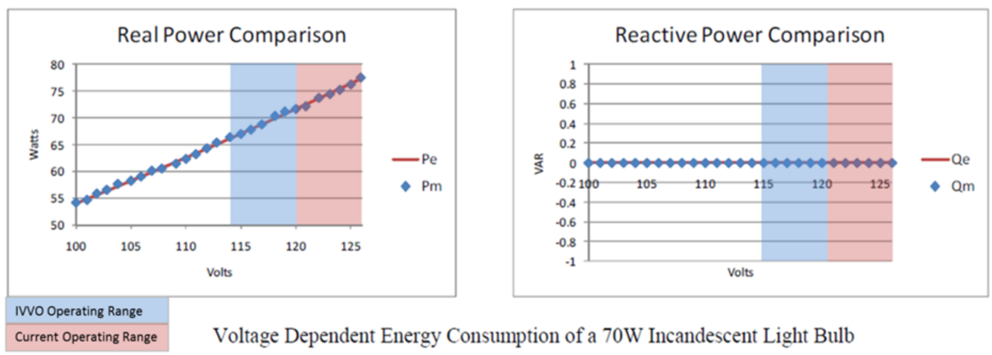
A. One example of how IVVO will result in electricity savings is incandescent lighting, where the power consumed is directly proportional to the voltage. (For such a load, the formula $P=V^2/R$ applies, where P=power, V=voltage, and R=resistance). As shown in Figure 18, a 70W incandescent light bulb will consume around 77W at a higher voltage level of 126V and around 66W at a lower voltage level 114V. This type of load can be referred to as a constant-impedance load.

But other loads react differently, and power demand is influenced less by a reduction in voltage. For instance, the effect of a change in voltage on the demand for compact fluorescent light bulbs is shown in Figure 19 below. Analysis show the impact of voltage change on demand for CFLs is roughly half of that for the incandescent bulb (Figure 18). While the focus in on the reduction of real power, the graphics below depict the effect of change in reactive power for the benefit of understanding the impact.

Other loads, especially electronics and most LEDs, respond even less to changes in voltage - exhibiting a constant-power behavior. Lastly, we note that energy savings is function of power over time, and that the benefit analysis does endeavor to takes this factor into account.

Figure 18

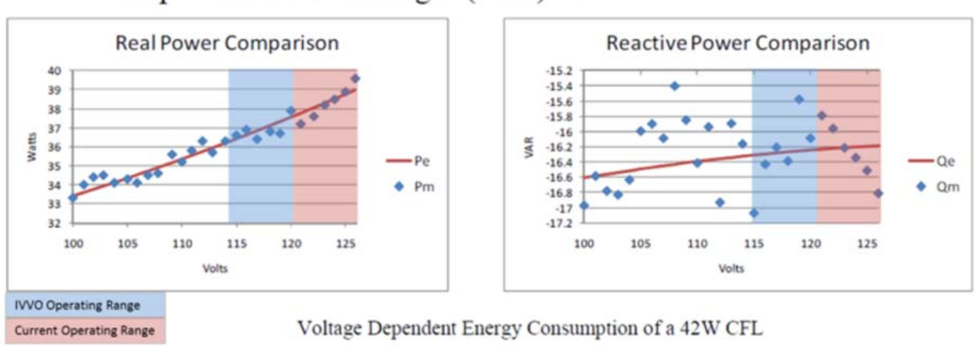
Incandescent Light Bulb (70W)



Voltage Dependent Energy Consumption of a 70W Incandescent Light Bulb

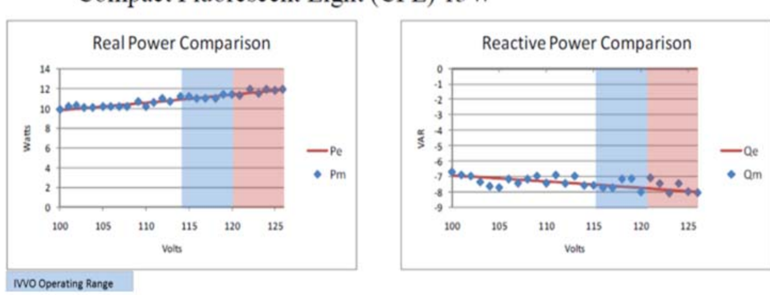
Figure 19

Compact Fluorescent Light (CFL) 42W



Voltage Dependent Energy Consumption of a 42W CFL

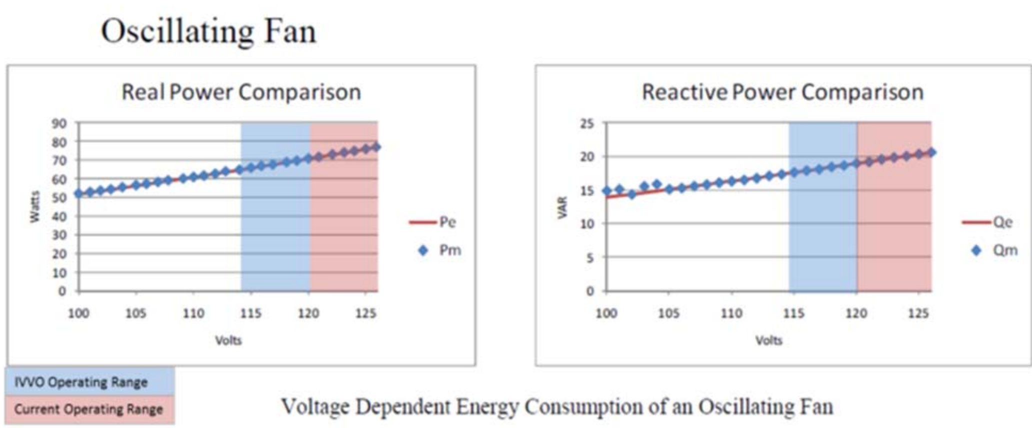
Compact Fluorescent Light (CFL) 13W



Q. ARE THERE OTHER BENEFITS ASSOCIATED WITH OPERATING ELECTRICAL DEVICES AT A LOWER VOLTAGE?

A. Yes. Some motors, such as those found in air conditioners, dryers, refrigerators, and oscillating fans operate more efficiently at a lower voltage (114V to 120V). A higher voltage (120V to 126V) generates more heat, which makes these motors less efficient. Figure 20 shows the reduced voltage level and energy consumption for an oscillating fan with IVVO.

Figure 20



Voltage Dependent Energy Consumption of an Oscillating Fan

Q. HOW DID XCEL ENERGY DETERMINE THE ENERGY SAVINGS LEVEL THAT IT ANTICIPATES ACHIEVING FROM THE CORE DEPLOYMENT OF IVVO IN MINNESOTA?

A. Xcel Energy developed the energy savings level based on information learned from pilot programs (one in Minnesota and two in Colorado) and then translating these results into a reduction that would be achievable for the Minnesota area where IVVO will be deployed based on an examination of the system characteristics core deployment area and engineering judgment.

Q. PLEASE DESCRIBE THE IVVO PILOT PROGRAMS THAT YOU MENTIONED.

A. These pilot programs were the: 1) the Wilson Substation pilot that was conducted in 2014-2015 in Bloomington, Minnesota and 2) two pilot projects conducted by PSCo in 2011-2012 to estimate the energy savings for their IVVO deployment in Colorado.

Q. WHAT WAS THE WILSON SUBSTATION PILOT?

A. The purpose of the Wilson Substation pilot was to test and measure the impact of voltage reduction on energy use for Minnesota customers served by this substation in Bloomington. Due to equipment issues, the most substantial testing was done in October 2014 and February 2015. The pilot used the test method of alternating the Load Tap Changer set point between two settings – the normal setpoint and one 3 percent lower. As has been done nationally with many other pilot studies, testing was done day-on, day-off, and weekend-on, weekend-off to test the system's response to reduced voltage.

To determine the impacts, we compared on-days to off-days, and on-weekends to off-weekends. We also filtered out abnormalities in the data including abnormal feeder conditions and attempted to compare similar days to each other. The results of the Wilson pilot identified a CVR factor of between 0.88 and 0.91.

Q. WHAT IS A CVR FACTOR AND HOW DOES IT TRANSLATE INTO A REDUCTION IN ENERGY CONSUMPTION?

A. CVR factor is a term commonly used to refer to the ratio between voltage reduction and energy load consumption for a portion of the Distribution system. Generally, a CVR factor of 1.0 means that for a 1 percent drop in voltage, there is a 1 percent drop in energy consumption. As a result, the Wilson pilot results suggest that a 3 percent reduction in voltage would result in an over 2 percent reduction in energy consumption.

Q. WHAT ARE THE ISSUES WITH USING THE RESULTS OF THE WILSON PILOT TO THE PREDICT THE ENERGY SAVINGS FROM THE PROPOSED IVVO CORE DEPLOYMENT?

A. The biggest issue is that this pilot was conducted on only a small portion of our system (one substation), and the results may not accurately predict benefits on other areas of our system. This is because CVR factors vary widely across our system and can range from as low as 0.4 to as high as 1.5.

Q. WHY IS THERE SUCH A RANGE OF CVR FACTORS ACROSS THE MINNESOTA SYSTEM?

A. This is not an exhaustive list but some of the factors that can impact the CVR factor include: (1) length of feeders; (2) conductor sizing; (3) type, size, and location of different loads; and (4) type, size, and location of DER. The type of load on feeder has a significant impact on the CVR factor. For instance, commercial and industrial load tend to have lower CVR factors while highly resistive load such as old lighting (i.e., non-LED) tends to have higher CVR factors. With the transition to LED lighting, as well as the use of additional constant power devices, we expect that CVR factors will decline in the future across our system.

Q. ARE THERE OTHER FACTORS THAT IMPACT THE USEFULNESS OF THE WILSON PILOT RESULTS IN PREDICTING ENERGY SAVINGS FROM THE PROPOSED CORE DEPLOYMENT OF IVVO?

A. Yes. The Wilson pilot does not account for the declining use per customer that we have seen and expect to continue to see in the future due to energy efficiency and conservation measures. This declining use per customer reduces the potential benefits of IVVO.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE IVVO PILOTS PERFORMED BY PSCO?

A. PSCo conducted two pilots in 2011 and 2012 to test IVVO at two substations, the Englewood Substation and the National Center for Atmospheric Research (NCAR) Substation, through its participation in the Electric Power Research (EPRI) Green Circuits program.

Q. WHAT WERE THE RESULTS OF THESE TWO COLORADO PILOTS?

A. The results of the NCAR pilot found that voltage could be lowered on average about 2.5 percent with corresponding energy savings of about 2.5 percent in 2011. The results from the Englewood Substation showed a voltage reduction of 1.5 percent and a CVR factor of 1.7 in 2011 and 2.7 in 2012, which would result in estimated energy savings of 2.55 percent and 4.05 percent. The results for both the NCAR Substation and the Englewood Substation pilots was higher than the nation-wide average for field trials with other utilities that showed an energy reduction range of 1.6 percent to 2.7 percent.

Q. DOES THE COMPANY BELIEVE THAT THE SAME LEVEL OF ENERGY SAVINGS FROM THESE TWO COLORADO PILOTS COULD BE ACHIEVED IN MINNESOTA?

A. It is unlikely. There are key differences between the Minnesota and Colorado distribution systems that will impact the effectiveness of IVVO such that the same level of energy savings is not likely to materialize in Minnesota. These key differences include:

- *Standard substation bus voltage is lower in Minnesota:* In PSCo, the standard bus voltage is 125V, which is at the very high end of the ANSI C84.1 standard for distribution voltage. This higher starting voltage allows for the potential for greater voltage reduction to be done by IVVO which then results in greater energy savings without compromising service quality. In contrast, the standard bus voltage for the Minnesota service territory is typically 123.5V. This lower starting point reduces the potential energy savings that can be achieved in Minnesota from IVVO.
- *As compared to Minnesota, Colorado uses shorter feeders with larger conductors to support a denser load*: Large conductor size has lower impedance, which means that the voltage drop across the feeder is reduced which allows the Colorado system to achieve better results. In addition, the higher load density on each feeder means that the net impact from IVVO on a per-feeder basis will be greater than it will be in Minnesota.
- *Minnesota has a greater proportion of overhead construction as compared to Colorado*: Overhead construction inherently has greater voltage drop than underground construction. As a result, there is less opportunity for IVVO to further reduce voltage in Minnesota.

Q. HOW DID XCEL ENERGY DETERMINE THE ENERGY SAVINGS LEVEL FOR MINNESOTA BASED ON THESE PILOT PROGRAMS?

A. We examined the results of the various pilot programs discussed above and accounted for the limitations of this data. We also evaluated the characteristics of the area of the system that is planned for the core deployment for IVVO. For example, we evaluated the average feeder head-end voltage, typical loads, line design, and customer density. We also took into account that fact that IVVO may not be available at all times of the day due to abnormal configurations or maintenance.

Q. WHAT LEVEL OF ENERGY SAVINGS DOES XCEL ENERGY BELIEVE IS ACHIEVABLE HERE IN MINNESOTA?

A. Ultimately, we believe that 1.0 percent is the most readily achievable energy savings level, but we are not setting a limit on these savings at this time. After the IVVO devices are deployed, the Company will lower the voltage to the extent that the system allows and seek to achieve the maximum savings within each substation transformer area. To account for the potential for higher energy savings once the IVVO devices are deployed, we identified 1.5 percent as the higher end of the range of energy savings that may be achievable. For purposes of the CBA, we utilized the mid-point of the range between 1.0 percent and 1.5 percent energy savings or 1.25 percent as our reference case. However, we also present as sensitivities in the CBA that utilize the lower (1.0 percent) and upper (1.5 percent) ends of the identified range.

Q. WILL THE ENERGY SAVINGS FROM IVVO RESULT IN OTHER BENEFITS?

A. Yes. There will be environmental benefits associated with the increased energy efficiency. Improved energy efficiency can result in reduced demand for electric generation and thus a reduction in carbon emissions caused by certain types of generation. The reduction in carbon emissions, in turn, will provide environmental and societal benefits. The Company's calculation of these benefits is described by Dr. Duggirala.

(2) Electrical Loss Reductions

Q. HOW WILL IVVO REDUCE ELECTRICAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. For any conductor in a distribution network, the current flowing through it can be broken down into two components – active and reactive power. Active power is measured in watts or kilowatts (one thousand watts) and is the energy required to perform actual work. Reactive power is measured in "VAr" or "kVAr" (one thousand VAr); it does not do real work but uses the current-carrying capacity of the distribution lines and equipment, and contributes to the power loss. Reactive power compensation devices (such as capacitors) are designed to reduce the unproductive component of the electric current, thereby reducing current magnitude, and thus, reducing energy losses.

For Xcel Energy's system, ADMS will turn the system's capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on each portion of the distribution system. This improves the efficiency of the system and reduces system losses.

Q. HOW, SPECIFICALLY, IS THE ADMS CONTROL METHOD AN IMPROVEMENT ON SMARTVAR?

A. ADMS is able to calculate the reactive power needs of each section of line and optimize for the circuit. SmartVAr does optimize power factor as measured at the substation, but uses a pre-selected sequence to energize the capacitors.

The ADMS method is superior and will result in additional loss reduction, relative to SmartVAr.

Q. WHAT ARE THE ELECTRICAL LOSSES SAVINGS THE COMPANY ANTICIPATES ACHIEVING FROM IVVO?

A. The initial deployment of IVVO at 13 substations is expected to reduce annual electrical losses by 225 MWh in 2022, rising to approximately 900 MWh in 2025. This improvement, incremental to the SmartVAr program, is due to the additional capacitance deployed as part of the IVVO program

Q. HOW DID THE COMPANY CALCULATE THE ESTIMATED ELECTRICAL LOSS SAVINGS ANTICIPATED FROM IVVO?

A. As with the calculation of energy use reduction described above, we leveraged our extensive analysis for PSCo to calculate the potential for loss reduction in NSPM. The energy loss reduction quantified for purposes of the CBA is achieved through improvement to the power factor of the feeder. Studies were completed in PSCo which found the reduced losses from improving the power factor by 4.5 percent (from 95 percent to 99.5 percent). We note that the available reduction in NSPM is less than Colorado, because our typical power factor in Minnesota – the "starting point" for these calculations - was higher (98 percent) than that in PSCo (95 percent). We calculated the portion of the reduced line losses that we expect in Minnesota to be 34 percent of what was expected in PSCo.

(3) Avoided Capacity Costs

Q. HOW DID XCEL ENERGY ESTIMATE THE AVOIDED CAPACITY COSTS THAT WILL RESULT FROM IVVO?

A. Xcel Energy is projecting that IVVO will reduce the NSP system's peak demand by 0.7 percent, which is directly attributable to the energy reduction achievable at system peak. Since the Company will be conducting a targeted, core deployment of IVVO, this 0.7 percent reduction was applied to core IVVO deployment area's contribution to the system peak load. The value of benefit was calculated using avoided Transmission, Distribution, and Generation capacity values for each year through 2038.

b. Non-Quantifiable Benefits

Q. ARE THERE OTHER BENEFITS OF IVVO THAT ARE NOT QUANTIFIABLE?

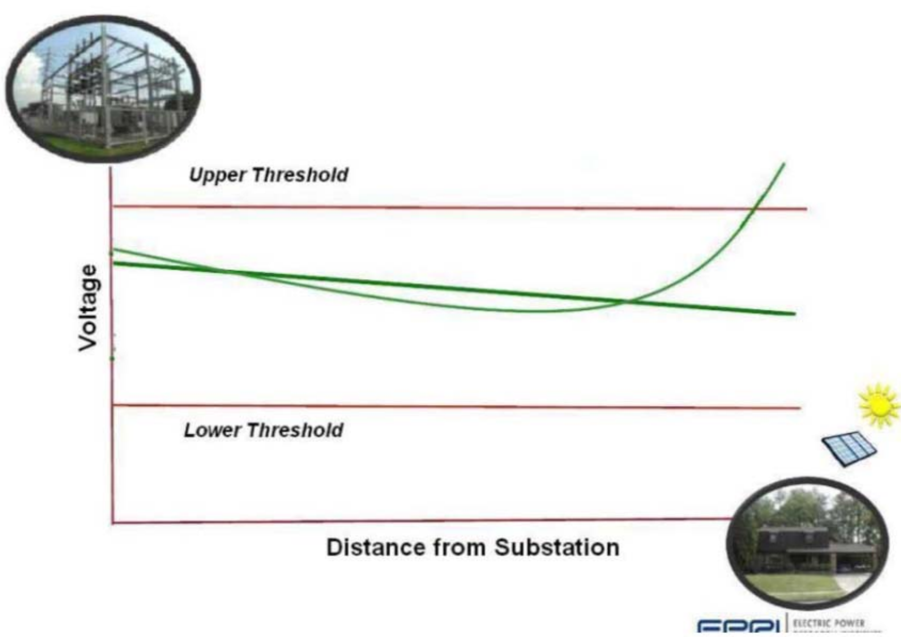
A. Yes. For those customers whose feeders are equipped with IVVO, we anticipate fewer voltage-related complaints due to the more active voltage control throughout. This will save operating labor to investigate and resolve complaints reactively. In addition, these customers will experience higher energy efficiencies from their personal electrical devices. This improved efficiency will result in lower bills for those customers. However, since the Company is not proposing to implement IVVO for the entirety of its service territory at this time, and these voltage and efficiency benefits would not apply to all customers, the Company chose not to quantify them for the CBA. Another benefit that we did not quantify is the increase in the system's ability to host DER that will result from IVVO.

Q. HOW WILL IVVO INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As penetration of DER grows, the Company will need to manage the DER's influence on voltage through distribution system voltage control. Traditionally, with one-way flows on a feeder, the voltage control objective was to raise voltage at times of heavy load to manage voltage within the acceptable range.

As shown in Figure 21 below, DER which injects power into the system, such as solar generation, increases the voltage on the edge of the grid, which will be most noticeable during times of lower energy use. By increasing the voltage at the end of the feeder, such DERs can cause over-voltage issues impacting both the DER and other customers. By lowering the voltage and reducing potential over-voltage impacts from solar DERs, IVVO will support the ability for additional solar to be hosted on the system.

Figure 21



Q. HAS THE COMPANY PREVIOUSLY STUDIED THE ABILITY OF IVVO TO IMPROVE HOSTING CAPACITY?

A. Yes. In our 2018 Hosting Capacity Study,[22] we studied the impact of lowering the voltage the substation bus voltage on the hosting capacity of five feeders. In that analysis we found increases in capacity between 0 and 700 kW.[23] IVVO, however, will apply its more robust control algorithms and system controls to provide greater average improvement in hosting capacity although some feeders will gain significantly, while others may remain constrained by voltage or thermal ratings.

The EPRI publication, "Value of a Distribution Management System for Increasing Hosting capacity: Centralized vs. Autonomous Control of Distributed Energy Resources" published in December 2018, provides some insight into how the ADMS can provide an increase in Hosting Capacity through voltage control.

Q. WHY IS XCEL ENERGY UNABLE TO QUANTIFY THE INCREASE IN HOSTING CAPACITY THAT WILL BE ENABLED BY IVVO?

A. Hosting capacity can be constrained by factors other than voltage, such as thermal or protection issues. Each feeder is unique in its topology and the distribution of loads along the feeder, both of which have a significant impact on the hosting capacity. And finally, the distribution of DER along the feeder has a significant impact on the hosting capacity. Consequently a robust hosting capacity analysis needs to be conducted on every feeder where IVVO is installed in order to accurately quantify the system wide impact. While it is

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[22] XCEL ENERGY'S 2018 DISTRIBUTION SYSTEM HOSTING CAPACITY STUDY, Docket No. E002/18-684 (Nov. 1, 2018).
[23] *Id.* at 26.

true that most feeders' hosting capacity may be constrained by high voltage at low load times, other constraints can appear as voltage is lowered on a given feeder, making it hard to approximate what could ultimately be gained. Due to these factors, the Company is unable to quantify and generalize the increase in hosting capacity which can be attributed to IVVO.

5. IVVO Costs

Q. WHAT ARE DISTRIBUTION'S CAPITAL AND O&M COSTS RELATED TO IMPLEMENTATION OF IVVO?

A. The table below provides the Distribution capital additions and O&M costs for IVVO implementation for 2020 through 2022.

Table 51

IVVO Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
IVVO	$0.0	$4.1	$6.7

Table 52

IVVO O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$0.4	$0.8

a. Distribution's Capital Costs

Q. WHAT ARE DISTRIBUTION'S CAPITAL COSTS ASSOCIATED WITH THE IVVO IMPLEMENTATION?

A. Distribution's principal capital costs for IVVO are the costs for the IVVO devices and their installation. There are four categories of capital costs for IVVO: 1) device costs; 2) device installation; 3) labor and external contracting; and 4) communications.

Q. WHAT IS INCLUDED IN THE DEVICE DOST CATEGORY?

A. The capital device cost category includes material and equipment costs for the IVVO devices (capacitors, SVCs, voltage sensing devices, and LTC controls).

Q. HOW DID THE COMPANY ESTIMATE THE COSTS OF THE IVVO DEVICES AND THEIR INSTALLATION?

A. As many of the devices involved in the IVVO deployment are not new to the Company, we were able to use historical costs to develop the capital cost estimates to implement the IVVO. With respect to the new SVC devices, Xcel Energy used our recent costs and experiences for PSCo. For installation, the Company will use primarily contract labor. The projected labor and installation costs were developed using contractor wage scales.

Q. HOW DID THE COMPANY GO ABOUT SELECTING VARENTEC AS THE VENDOR FOR SVCS?

A. As mentioned above, the Company determined that SVCs are a cost-effective way to complement an IVVO installation and mitigate localized voltage problems. The Company completed its RFP process and selected Varentec as its supplier of SVCs in 2018 to support our Colorado IVVO activities. We evaluated three different vendors based on a variety of factors including cost per unit, number of devices deployed across different utilities, support capabilities, and technical capabilities, ultimately selecting Varentec's ENGO unit as the best amongst these factors. Contract negotiations were completed in the third quarter of 2018, and we received our first shipment of SVC units late in the same quarter.

Q. HOW DID THE COMPANY SELECT THE POWERLINE SENSOR EQUIPMENT AND VENDOR FOR IVVO?

A. The market for powerline sensors that integrate into capacitor controls and provide the accuracy necessary for IVVO is small. The Company researched the available products' ability to meet our criteria, field tested samples. Ultimately we selected an upgraded sensor that performed well in these field tests. Since further improvements in this technology are anticipated, the Company will continue to monitor this evolving space and modify our vendor selection if appropriate.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE OTHER IVVO DEVICES?

A. Primary capacitors and LTC controllers are a stock commodity within the Company, and we were able to use our existing equipment standards to support this deployment. The equipment selected for our standards undergoes periodic review, using the RFP process when appropriate.

Q. WHAT IS INCLUDED IN THE DEVICE INSTALLATION COST CATEGORY

A. The device installation capital costs for IVVO include costs for installing the IVVO devices, including any supporting internal and contract labor.

Q. WHAT IS INCLUDED IN THE LABOR AND EXTERNAL CONTRACTING COST CATEGORY?

A. This category captures costs for commissioning IVVO devices and their circuits and enabling benefits through ADMS's functionality. It includes standing up the GEMS system and enablement of AMI bellwether functionality.

Q. HOW DID THE COMPANY ESTIMATE THESE CAPITAL COSTS?

A. The projected labor and installation costs were developed using contractor wage scales.

Q. WHAT IS INCLUDED IN THE COMMUNICATION COST CATEGORY?

A. The communications installation capital costs for IVVO include costs to install and commissioning equipment to ensure reliable, 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 IVVO deployment. We were able to use historical costs to develop the capital cost estimates. Our recent costs and experiences in PSCo provide confirmation that the estimates in use are reasonable.

b. Distribution's O&M Costs

Q. WHAT ARE THE O&M COSTS ASSOCIATED WITH IMPLEMENTING IVVO?

A. The O&M costs include O&M costs in support of capital deployment, asset and device support, minor device replacement, and training.

Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

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

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

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated these costs as a percentage of the number of installed IVVO assets.

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

A. This category includes material and labor to replace assets (components which are not property units) in good working order. The Company estimated these costs as a percentage of installed IVVO assets.

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

A. This category labor and incidental material to maintain communications link to IVVO assets. The Company estimated these costs as a percentage of the installed IVVO assets.

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

A. This category includes training costs for the IVVO program. The Company estimated these costs based on number of employees, the time to train them, and wage scales.

c. Distribution Contingency for IVVO

Q. PLEASE DESCRIBE THE IVVO CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. Distribution's IVVO budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 10 percent. This smaller contingency (compared to AMI) is considered adequate because the cost projections for devices and installation were developed based on historical costs and we believe we have fairly accurately estimated the quantity of equipment and cost of installation of the IVVO devices.

d. IVVO Expenditures 2020-2029

Q. WHAT ARE DISTRIBUTION'S CAPITAL EXPENDITURES AND O&M FORECASTS FOR IVVO FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M forecasts for IVVO for 2020 through 2029.

Table 53

IVVO Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
IVVO	$0.1	$4.6	$7.6	$14.3	$0.0

Table 54

IVVO O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
IVVO	$0.0	$0.4	$0.8	$0.5	$0.8

6. Alternatives to IVVO

Q. WHAT ALTERNATIVES TO IVVO DID THE COMPANY EVALUATE?

A. The Company evaluated four alternatives to IVVO: (1) maintaining the status quo; (2) implementing IVVO without the other AGIS components; (3) implementing IVVO without SVC devices,; and (4) delaying the deployment of IVVO.

Q. DESCRIBE THE STATUS QUO ALTERNATIVE AND WHY THAT ALTERNATIVE WAS REJECTED.

A. One alternative to implementing IVVO is to maintain the status quo, and this relies on the SmartVAr system to maintain good power factor. There are two primary drawbacks to staying with the status quo of SmartVAr which are: 1) forgoing the benefits of reduced energy usage; and 2) forgoing increased

DER hosting capacity. Those benefits are unavailable through SmartVAr because it is incapable of enacting CVR and enabling the system to operate at the lower levels which enable those specific benefits. Given that these two benefits are important to stakeholders, the Company, and its customers, maintaining the status quo is not a reasonable alternative.

Q. DID THE COMPANY CONSIDER IMPLEMENTING IVVO WITHOUT THE OTHER AGIS COMPONENTS?

A. Yes, however such a deployment would not be as efficient and as cost-effective as the proposed integrated deployment. This is because IVVO relies heavily on both the AMI meters and the FAN to operate. The AMI meters provide voltage sensing functions – measuring and transmitting voltage, current, and power quality data – that allow the Company access to more granular voltage data at the customer meter that makes IVVO more effective. IVVO also relies on the FAN infrastructure to communicate this data back to the Company.

Q. COULD THE COMPANY USE INDEPENDENT SENSORS RATHER THAN USING AMI METERS AS SENSORS?

A. Yes, but these sensors would not be nearly as cost-effective as the AMI meters. If independent sensors were utilized, the Company would need to install at minimum nine sensors per feeder and strategically locate these sensors to provide voltage sensing at the end of the line. Since these sensors would not be located at the customer meter, we would need to assume a conservative level of voltage drop from the sensor to the customer meter to ensure that voltages stay within required limits. This would limit our ability to optimize voltage levels as compared to using AMI meters that will provide precise voltage information at the service point. There would also be a significant additional cost associated with deploying independent sensors in place of AMI meters. We did estimate the additional cost for PSCo to use independent meters. Using those insights, we would anticipate a cost for the proposed NSPM deployment of over $4 million. The opportunity to leverage AMI meters provides the greater value.

Q. DESCRIBE THE ALTERNATIVE TO IMPLEMENT IVVO WITHOUT SVCS?

A. While IVVO could be implemented without any SVC devices, the SVCs will enable greater voltage reduction where deployed, thereby resulting in greater energy savings. In addition, the SVCs involved in the Company's proposed IVVO solution will increase the system's capacity to host renewables on the distribution system. SVCs will provide fast, variable voltage support that will help stabilize and regulate the voltage at the edge of the grid, near customers and DERs. Solar resources, in particular, are variable, intermittent, and non-coincident with peak demand, requiring more localized voltage support that is faster-acting than traditional utility devices. SVCs, as part of the IVVO solution, will help provide fast, variable voltage support limiting the impacts from solar and increasing the hosting capacity.

Q. DID THE COMPANY EVALUATE THE POSSIBILITY OF DELAYING THE DEPLOYMENT OF IVVO?

A. Yes. However, the Company determined that such a delay would likely result in a reduction in the energy savings benefit that will be achievable with IVVO. As a mentioned above, the transition to LED lighting and lower energy use per customer reduces the energy savings benefits of IVVO. These trends are expected to continue in the future, thus reducing IVVO's energy savings benefit. Further, delaying the deployment of IVVO has likely effect of increasing its costs due to inflation as well as potential increases in labor and material costs.

7. *Interoperability*

Q. HOW DOES THE COMPANY'S IVVO PROJECT ENSURE AND FACILITATE INTEROPERABILITY OF THIS TECHNOLOGY?

A. The Company plans to IVVO components that are vendor-neutral, non-proprietary, standards-based, and interoperable. This will allow the Company the ability to switch equipment vendors at any time and the new devices will be able to easily operate with the existing IVVO system and devices.

8. *Minimization of Risk of Obsolescence*

Q. HOW DOES THE IVVO TECHNOLOGY SELECTED BY THE COMPANY MINIMIZE THE RISK OF OBSOLESCENCE?

A. Xcel Energy has consistently sought to deploy assets that provide customer value over a long time period, a philosophy that has driven us to install quality equipment at the best price we can negotiate. That philosophy remains foundational, in our selection and sourcing procedures, where criteria include financial viability and long-term performance. The equipment itself must be robust to survive in a harsh outdoor environment and meet industry established testing standards to ensure longevity. While we cannot guarantee the longevity of any specific vendor, these attributes help to ensure the products will remain supported.

For electronic equipment, we specify equipment which can be remotely upgraded with new firmware as functionality or security needs dictate.

Requiring interfaces to follow open protocols (e.g., DNP3, WiSUN) that are not vendor specific helps ensure interoperability between manufacturers. Standard physical interface requirements allow newer devices to connect and interface with controls that are well over 20 years old. We evaluate the equipment's physical and cybersecurity capabilities and require upgradability to help protect from unknown future cybersecurity threats. We are working with manufacturers to ensure they are building such security into their equipment.

Specifically with IVVO, we have selected equipment and controls that adhere to these principles and are highly configurable.

H. AGIS Distribution Overall Costs and Implementation

Q. OVER WHAT TIME PERIOD WILL THE FOUNDATIONAL COMPONENTS OF AGIS BE IMPLEMENTED?

A. The Company began implementation of ADMS, as well as limited deployment of AMI and the FAN in support of the Company's residential TOU pilot, in 2019. Full deployment of AMI, the FAN, and IVVO will begin in 2021 and will be substantially completed in 2024. FLISR implementation will also begin in 2021 and will be accomplished over a longer time period, through 2029.

Q. WHAT ARE THE TOTAL DISTRIBUTION COSTS FOR THE AGIS COMPONENTS?

A. The tables below show the total capital expenditure and O&M IT integration costs, by component, for 2020-2029.

Table 55

AGIS Capital Expenditures – Distribution NSPM - Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.6	$22.3	$133.9	$179.5	$14.1
FAN	$3.2	$6.2	$0.0	$0.0	$0.0
FLISR	$3.1	$8.1	$5.9	$16.0	$26.3
IVVO	$0.1	$4.6	$7.6	$14.3	$0.0
Total	**$9.0**	**$41.2**	**$147.4**	**$209.8**	**$40.4**
*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024					

Table 56

AGIS O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.3	$3.3	$5.0	$10.0	$15.7
FAN	$0.1	$0.2	$0.4	$0.3	$0.4
FLISR	$0.1	$0.3	$0.2	$3.2	$2.4
IVVO	$0.0	$0.4	$0.8	$0.5	$0.8
Total	**$2.6**	**$4.2**	**$6.5**	**$13.9**	**$19.3**
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024					

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION WITH RESPECT TO THE DISTRIBUTION COMPONENTS OF THE AGIS INITIATIVE?

A. I recommend that the Commission approve our request to recover Distribution's capital investments and O&M expense for the foundational components of AGIS that we propose to implement during the 2020-2022 term of the rate case. Our proposal includes full AMI implementation, IVVO and FLISR as part of our broader grid resiliency efforts, and the FAN components necessary to support AMI and the advanced grid applications. We also recommend that the Commission certify these projects to provide the opportunity for the Company to request recovery of costs for 2023 and later in subsequent rider filings. Approval of the costs necessary to implement the AGIS initiative will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers.

VI. 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 of my testimony I will describe the Company's EV programs and discuss the EV capital and O&M expenses included in the budget for 2020 to 2022.

Q. WHY HAS THE COMPANY INVESTED IN EV PROGRAMS?

A. EVs are becoming more prevalent as costs of ownership have decreased and consumers have become increasingly focused on utilizing greener energy. Customers have indicated that they want increased access to electricity as a transportation fuel, especially electricity generated from renewable resources.

Accordingly, the Company has sought to develop programs to support home charging, fleet charging, and public fast charging.

The Company has also developed EV programs in response to legislative and Commission directives aimed at decreasing the greenhouse gas emissions in the State. The Company is well positioned to develop EV programs and offerings that will help customers overcome barriers to EV adoption, maximize benefits to the grid, and minimize costs to both EV adopters and Xcel Energy customers in general.

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, 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."[24] 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."[25]

[24] Minn. Stat. § 216B.1614, subd. 2.
[25] *Id.*

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.[26] 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. EVs present an opportunity to leverage utility decarbonization efforts and reduce emissions across both the electric utility and transportation sectors. 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."[27]

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

A. The Company is seeking to recover capital and O&M expenses for 2020 to 2022 for several EV projects, including: three EV Pilot Programs that were just recently approved by the Commission—Fleet EV Service Pilot, Public Charging Pilot, and the Residential subscription service pilot; and the new

[26] *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).
[27] *Id.*

pilots and programs the Company highlighted in its Transportation Electrification Plan (TEP), including the EV home service program, a vehicle-to-grid school bus pilot, a new smart charging offering for residential customers (Charging Perks), a new Commercial EV rate, and a multi-family charging pilot.

Q. WHAT ARE THE OVERALL CAPITAL AND O&M COSTS THAT THE COMPANY HAS INCURRED FOR EV PILOT COSTS?

A. Tables 57 and 58 below provide the budgeted capital additions and the portion of the O&M budget for the Company's planned EV programs that the Company has included in its base rate request:

Table 57

Overall EV Program Capital Costs

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (includes AFUDC)	2020 Budget	2021 Budget	2022 Budget
Capital Additions	$9.8	$8.3	$10.1

Table 58

Overall EV Program O&M Expenses Included in Rate Case

(Dollars in Millions)

NSPM – Total Company Electric (Dollars in Millions)	2020 Budget	2021 Budget	2022 Budget
O&M Expenses	$0.8	$0.7	$0.7

I note, however, that certain O&M expenses associated with these programs were inadvertently omitted from the rate case O&M budget due, in part, to the timing of the approval of these items in July 2019 and the rate case budget finalization that also occurred during that same time frame. These omitted O&M amounts are: (1) $2.3 million (2020); (2) $2.7 million (2021); and (3) $2.3 million (2022). As Company witness Mr. Benjamin C. Halama notes, the Company proposes to include these omitted O&M amounts either as a rebuttal adjustment in this rate case or to continue use of the EV tracker account that was established in Docket No. E002/M-15-111 to track these costs for future recovery.

B. EV Project Capital and O&M Expenses

1. Fleet EV Service Pilot

Q. PLEASE DESCRIBE THE FLEET EV SERVICE PILOT.

A. Through the Fleet EV Service Pilot, the Company will install and maintain EV infrastructure for non-residential customers operating fleets of light-, medium-, or heavy-duty EVs. The Company would install, own, and maintain infrastructure, and if requested by a customer, would also install, own, and maintain charging equipment. More specifically, Xcel Energy will seek to support the installation of more than 700 charging ports, which will initially serve Metro Transit, the Department of Administration, and the City of Minneapolis, along with a modest number of other eligible customers.

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

A. The Company proposed the fleet market 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. It will also allow a deeper understanding of the EV system benefits and how to best socialize costs, especially in the fleet market, 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. HAS THE FLEET EV SERVICE PILOT BEEN APPROVED BY THE COMMISSION?

A. Yes. The Commission approved both the EV Fleet Service Pilot and the Public Charging Pilot, which is discussed below, with minor modifications in its July 17, 2019 Order in Docket No. E002/M-18-643.

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

A. Fleet EV Service Pilot capital expenses fall into two categories: EV service connection infrastructure; and EV charging infrastructure. 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. Charging infrastructure includes new panels, conduit, and wiring up to the charger (EV supply infrastructure) and the charging equipment as well as any necessary civil construction work in compliance with state and local codes.

Table 59
Fleet Capital Additions
(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (excludes AFUDC)	2019 Forecast	2020 Budget	2021 Budget	2022 Budget
Fleet Capital Additions	$0.7	$4.3	$3.3	$4.3

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

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.

Q. HOW DOES THIS BUDGET COMPARE TO THE BUDGET PROVIDED TO THE COMMISSION IN DOCKET NO. E002/M-18-643?

A. The budget for the Fleet EV Service pilot remains the same, and the Company plans to implement the pilot over a three-year period. The 2022 budget assumes the Company will continue to spend supporting fleets beyond the pilot period, which will end in the middle of that year. The future permanent fleet offering will need to be developed based upon learnings from the pilot, and approved by the Commission prior to launch.

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. WHAT IS THE TIMING OF IMPLEMENTATION OF THE FLEET EV SERVICE PILOT?

A. Projects have already begun, with the Company working on the make-ready infrastructure project for Metro Transit's electric buses that the Company discussed in its Petition in Docket No. E002/M-18-643. The Company is continuing to recruit customers for the three-year pilot. The Company expects to incur most of the spend in 2020 and 2021, with some continued spend in 2022.

2. Public Charging Pilot

Q. DESCRIBE THE PUBLIC CHARGING PILOT.

A. Through the Public Charging Pilot, Xcel Energy will install, own, and maintain EV charging infrastructure for developers of public direct current fast-charging stations within the Company's service territory. 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. Unlike the Fleet EV Service Pilot, the Company would not own or maintain any charging equipment. 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.

Like the Fleet EV Service Pilot, the Public Charging Pilot will allow a deeper understanding of the EV system benefits and how to best socialize costs, and will provide a platform for the Company to evaluate models for expanding infrastructure to enable the addition of more public EV charging stations throughout the State. 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. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE PUBLIC CHARGING PILOT BUDGET?

A. Public Charging Pilot capital expenses fall into two categories: EV service connection infrastructure; and EV supply infrastructure. Service connection infrastructure covers all equipment on the utility's traditional side of the 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. Supply infrastructure includes new panels, conduit, and wiring up to the charger as well as any necessary civil construction work in compliance with state and local codes. For the public charging pilot, site hosts and developers are responsible for the procurement, installation, and maintenance of charging equipment. The capital additions budget for the Public Charging Pilot is included in Table 60.

Table 60
Public Charging Capital Additions
(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (excludes AFUDC)	2020 Budget	2021 Budget	2022 Budget
Public Charging Capital Additions	$3.7	$3.1	$4.3

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE PUBLIC CHARGING PILOT?

A. Similar to the Fleet EV service pilot, 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 relied on a third-party consultant (Atlas Public Policy) to help benchmark our numbers by identifying and sharing other EV infrastructure studies and utility proposals and reports.

Q. HOW DOES THIS BUDGET COMPARE TO THE BUDGET PROVIDED TO THE COMMISSION IN DOCKET NO. E002/M-18-643?

A. Similar to the Fleet EV Service pilot, the budget remains the same, and the Company plans to implement the pilot over a three-year period. The 2022 budget assumes the Company will continue to support public charging beyond the pilot period, which will end in mid-2022. The future public charging offering will need to be developed, based on learnings from the pilot, and approved by the Commission prior to launch.

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

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

Q. WHAT IS THE TIMING OF IMPLEMENTATION OF THE PUBLIC CHARGING PILOT?

A. The Company is continuing to recruit customers and work with partners at the cities of Minneapolis and Saint Paul to identify potential sites for the pilot. Additionally, the Company has been attending the Minnesota Pollution Control Agency's meetings on the phase 2 of the VW Settlement/Minnesota Diesel Replacement Program. The Company expects to incur most of the spend in 2020 and 2021, with some continued spend in 2022.

3. *Evaluation and Stakeholder Group for Fleets and Public Charging Pilots*

Q. WHAT EVALUATION AND STAKEHOLDER GROUP ACTIVITIES DOES THE COMPANY PROPOSE FOR THE TERM OF THE MULTI-YEAR RATE PLAN?

A. In order to gather feedback and input from stakeholders, ensure transparency and share lessons learned, as well as to assess our customers' experiences and perceptions about EVs that could lead to increased adoption, we propose to:

- *Host semi-annual advisory group meetings with support from a facilitator.* These meetings are intended to foster discussion about pilot progress, gather ideas for continuing to improve pilots as well as new initiatives, and discuss how the pilots should scale or may be redesigned.
- *Provide data on key metrics in an annual EV compliance report.* Throughout these pilots, we will provide updates on key metrics emphasized in our stakeholder workshops in our annual June 1st EV compliance report.
- *Engage third-party evaluators to conduct an interim and final evaluation.* These evaluations of the pilots will provide information on certain metrics highlighted during our stakeholder workshops such as the customer experience, the impact pilot programs have on customer perceptions of electric vehicles, and impacts on EV adoption.

4. *EV Awareness, Education, and Outreach*

Q. PLEASE DESCRIBE THE EV AWARENESS, EDUCATION, AND OUTREACH THAT THE COMPANY PROPOSES FOR THE TERM OF THE MULTI-YEAR RATE PLAN.

A. The Company has continually expanded its mass-market electric vehicle advisory efforts. We focus on awareness, outreach, and education. These efforts span multiple communication channels including sponsorship of community events, digital media, and traditional media channels like radio and print, and engagement with trade partners.

Although many customers have general familiarity with EVs, many are not aware of all the facts and benefits of driving electric. Our strategies build EV awareness and promote Xcel Energy's programs through a number of different channels that are convenient and understandable.

EV-related print and updated web content serve as educational pieces for customers that align with our service offerings. The Company also connects directly with customers through community events which enable education through open dialogue. Event presence provides the opportunity to share EV information while gathering feedback and learning more about customer perceptions of EVs. Finally, Xcel Energy has promoted its EV driver options to the auto industry and to electricians who install EV chargers.

One specific example of the Company's expanded advisory efforts for EVs is its development of an online EV advisor tool (EV Advisor) that is designed to be integrated into the Company's website. The EV Advisor has launched and will continue to be refined to provide customers with information on what EV options are best for them and the benefits of EVs.

5. New Programs and Pilots Highlighted in Transportation Electrification Plan

Q. PLEASE DESCRIBE THE PROGRAMS AND PILOTS HIGHLIGHTED IN THE TRANSPORTATION ELECTRIFICATION PLAN

A. The Company's Transportation Electrification Plan (TEP), which was filed on June 28, 2019 in Docket No. E999/CI-17-879, highlighted multiple programs and pilots in development to support the EV market. The programs discussed in the TEP include: Residential Smart Charging Pilot (Charging Perks); Expansion of Residential EV Service Pilot to Standard Offering; Residential EV Subscription Service Pilot; Vehicle-to-Grid Demonstration with School Buses; Metro Transit Additional Infrastructure and Other Fleet Services offerings; Commercial EV Rate; and Multi-Family Housing Charging offering.

Q. WHAT ARE THE BENEFITS OF THE TEP PROGRAMS AND PILOTS?

A. Following the Commission's order in Docket No. E002/17-879, the Company developed its Transportation Electrification Plan to outline near-term plans to support EVs in our system. The TEP focuses on three EV charging market segments: home charging, fleet charging, and public/fast charging. From many sources and our own engagement with customers, we believe that these three market segments cover the majority of charging activity today. Our TEP also focuses on three key barriers that utilities are well-positioned to address: lack of information and awareness, upfront costs, and insufficient incentives to charge when energy costs are lowest.

We have developed our TEP to be aligned with the guiding principles we proposed and refined with inputs through 2018 stakeholder workshops, which were facilitated by Great Plains Institute. These guiding principles are to:

- Empower customers with information, tools, and options,
- Increase access to electricity as a transportation fuel in an equitable manner,
- Encourage efficient use of the power grid and integrate renewable energy,
- Improve air quality and decrease carbon emissions,

- Ensure reliability, interoperability, and safety of equipment,
- Leverage public and private funding opportunities,
- Provide benefits to all customers, both EV drivers and non-EV drivers, and
- Ensure transparency and measure results.

Q. PLEASE DESCRIBE THE RESIDENTIAL SMART CHARGING PILOT (*CHARGING PERKS*).

A. The Company is the process of developing a smart charging electric vehicle pilot, called *Charging Perks*, that is intended to capture demand savings opportunities presented by electric vehicles. The pilot will provide incentives to customers for demand response-capable equipment that the Company can use to manage when a customer is charging their vehicle. The Company previously proposed a version of this pilot as part of its Conservation Improvement Program (CIP), but did not receive approval because the Department of Commerce determined that the program did not fit specifically within the CIP statutory framework.[28] The Department did, however, indicate that the "decision to deny Xcel's Petition is in no way a reflection of the Department's view of the importance of EVs or optimal EV charging" … and "encouraged Xcel and other utilities to continue to seek alternative regulatory and funding mechanisms with which to implement programs like Charging Perks."[29] The Company plans to seek approval of the *Charging Perks* pilot within the next two years.

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[28] *In re Xcel Energy's Petition to Modify its 2017-2019 Conservation Improvement Program (CIP) Triennial Plan*, Docket No. E,G002/CIP-16-115, DECISION, at p. 11 (June 12, 2019).
[29] *Id.*

Q. PLEASE DESCRIBE THE EXPANSION OF RESIDENTIAL EV SERVICE PILOT TO A STANDARD OFFERING.

A. The Residential EV Service Pilot eliminated the need for customers to install a second meter by having the Company install EV charging equipment that provides billing quality energy usage data, which allowed participating customers to take EV charging service under a TOU energy rate that incentivizes charging during off-peak periods. Due to the success of the pilot in lowering participants' EV charging costs and encouraging off-peak charging, the Company filed a Petition in Docket No. E002/M-19-559 on August 30, 2019 seeking to make the program a permanent offering called Electric Vehicle Home Service. Customers will have the option to pay for the EV charging equipment and installation costs either upfront or through monthly charges. The permanent offering will use a three-period TOU rate structure as opposed to the two-period structure in the pilot, which should further encourage charging during the low peak periods.

Q. PLEASE DESCRIBE THE RESIDENTIAL EV SUBSCRIPTION SERVICE PILOT.

A. The Residential EV Subscription Service Pilot builds upon and complements the Residential EV Service Pilot by addressing a different barrier to EV adoption for some customers: difficulty assessing the economics of EV charging, including the potential benefits of time-of-use rates. This Subscription Service pilot includes many of the same features as the Residential EV Service, including Company-offered charging equipment that serves as a load monitoring device to measure EV energy use separately from the rest of the home, with payment options for customers. As part of the pilot, we will test the hypothesis that the simplicity of known monthly at-home charging costs could encourage EV adoption. The Commission approved the Residential EV Subscription Pilot with minor modifications on October 7, 2019 in Docket No. E002/M-19-186.

Q. PLEASE DESCRIBE THE VEHICLE-TO-GRID DEMONSTRATION WITH SCHOOL BUSES.

A. The Company is in the process of developing a demonstration project that would test the use of electric school bus batteries as grid resources. This type of pilot can deliver learnings about the use of bus batteries as energy storage resources and also collect information related to local peak demands. The Company is currently identifying vendors and school districts to participate in a demonstration project. The Company plans to submit a request for approval of a pilot demonstration project to the Commission once the program has been developed, participants have been identified, and program viability has been confirmed.

Q. PLEASE DESCRIBE THE METRO TRANSIT ADDITIONAL INFRASTRUCTURE AND OTHER FLEET SERVICES OFFERINGS.

A. The Company has had discussions with Metro Transit on partnering for even larger fleet electrification efforts. Metro Transit is considering adding bus charging capabilities to a new bus garage planned for the North Loop area of Minneapolis. Metro Transit plans to add charging infrastructure for up to 100 buses at this new facility. Beyond charging infrastructure, the new garage project may also include work that supports advanced energy infrastructure. The Company plans to submit a proposal to the Commission once sufficient program details have been developed and confirmed with Metro Transit.

Q. PLEASE DESCRIBE THE COMMERCIAL EV RATE.

A. In Docket No. E002/M-18-643, the Commission recognized "that the Company's proposed rate design with a twelve-hour on- and off-peak period, as applied to commercial customers, is reasonable but is perhaps not optimal for public EV charging[.]"[30] As a result, the Commission required the Company "to file, within six months, a commercial EV charging tariff that is more reflective of hourly system costs with price signals to reduce peak demand." Accordingly, the Company developed and included in this rate case a new commercial three-part TOU rate that will be available on a voluntary basis to all commercial EV customers. This rate is discussed in more detail in the Direct Testimony of Company witnesses Mr. Lon M. Huber and Mr. Steven V. Huso.

Q. PLEASE DESCRIBE THE MULTI-FAMILY HOUSING CHARGING OFFERING.

A. The Company is investigating an EV offering focused on multi-family housing, which presents additional considerations and challenges when compared to the general residential EV service offerings. The Company anticipates bringing forward a multi-family housing EV charging proposal within the next two years.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE TEP PROGRAM AND PILOTS BUDGET?

A. Capital investments for the Residential EV Subscription Service pilot approved in Docket No. E002/M-19-186 and the EV Home Service program, proposed in Docket No. E002/M-19-559, are included in our projected

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[30] *In re 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, at p. 16 (July 17, 2019).

budget for installed charging equipment. We acknowledge that the EV Home service program has only been proposed and not yet approved by the Commission, and the Company will not incur these costs unless this program is approved.

Table 61

TEP Programs and Pilots Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Plant Additions (excludes AFUDC)	2020 Budget	2021 Budget	2022 Budget
Capital	$1.6	$1.7	$1.2

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE TEP PROGRAMS AND PILOTS?

A. The EV Home Service program's capital budget is based on our experience with the Residential EV Service Pilot for installed charging equipment costs, which were lower than our anticipated costs when the pilot was launched. For the other pilots, we developed budget estimates based on our experiences with other EV pilots as well as by benchmarking costs against other utilities' proposals for similar types of pilots.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE TEP PROGRAMS AND PILOTS?

A. Yes. The O&M expenses for the TEP programs and pilots will fall into the following categories: program management and advisory services.

Q. WHAT IS THE TIMING OF IMPLEMENTATION OF THE TEP PILOTS?

A. The Company filed a petition seeking approval of the EV Home Service program in Docket No. E002/M-19-559, and hopes to implement the program starting in 2020. The approved Residential EV Subscription pilot will also launch in 2020. The Company intends to file petitions for approval for the other programs and pilots during the two-year TEP period.

VII. 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 last 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.[31] 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. 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 HPS fixtures, the increased cost was projected to be largely offset by

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[31] *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).

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 re-lamping 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,[32] 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.

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

[32] *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).

rate energy, and d) demand allocation," and to present this information in the next rate case.[33] I will be addressing a) and b) above, while Mr. Huso 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 $920,000 per year in relamping costs since 2015. This equates to approximately $4.6 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 88 percent reduction in street light outages reported for cobra head lights in Minnesota each month. Table 62 provides details on the annual number of street light outages reported from 2015 to 2019 for all Street Light Outages under Rate Code A30 and Table 62 for just cobra head lights under the A30 Rate Code.

[33] *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).

Table 62

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%	
2018	5,357	51%	
2019 Projected	3,713	66%	Conversion completed in May, 2019. Full year 2019 projection based upon 2,166 year-to-date outages as of August 21, 2019

Table 63

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%	Conversions began in August 2016
2017	6528	35%	
2018	4118	59%	
2019	817 YTD/1225 YE estimate	88%	Conversion completed 4/30/19. Saving is estimate based on 1225 estimated year end outages

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.

VIII. MINIMUM SYSTEM STUDY AND ZERO INTERCEPT ANALYSIS

A. Overview

Q. HOW IS THE DISTRIBUTION ORGANIZATION INVOLVED WITH THE MINIMUM SYSTEM STUDY AND ZERO INTERCEPT ANALYSIS?

A. As explained by Company witness Mr. Michael A. Peppin, the Company has completed both a Minimum System Study and a Zero Intercept Analysis. With regard to the Minimum System Study, Mr. Peppin explains there are four steps associated with performing a minimum system study. The Distribution Operations organization is primarily involved in the first step of the analysis, namely establishing the minimum-size conductor, cable, transformer, and secondary service equipment that is currently being installed on the distribution system. This work is performed by the Distribution Engineering organization within Distribution Operations.

With regard to the Zero Intercept Analysis, Distribution Operations is involved with establishing the load carrying capacity of each conductor, cable, transformer, and secondary service equipment studied. Distribution Operations is also involved with the interpretation of the cost data available for each specific conductor, cable, transformer and secondary service equipment to ensure the accuracy of the study results. This work is performed by the Distribution Engineering organization within Distribution Operations.

B. 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 63, 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 64 below provides a summary of the minimum-size equipment utilized in the Minimum System Study.

Table 64

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 64 above, overall, the Table 64 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.

C. Conductors and Cables

Q. PLEASE DISCUSS THE CRITERIA CONSIDERED BY THE ENGINEERING ORGANIZATION IN ESTABLISHING THE MINIMUM-SIZE CONDUCTORS AND CABLES.

A. Minimum conductor sizing for the Company's primary distribution systems (*i.e.*, overhead and underground) have been generally sized to a 150-200 amp capacity for "tap-level" systems. This amp rating for "tap-level" systems is generally driven by the maximum rating of other necessary system components available throughout the industry. Conductor strength is also a consideration for overhead taps. Tap level conductor minimum-size (and therefore its capacity) is further influenced by minimum strength required to: 1) withstand weather events and 2) enable reasonable span lengths between poles.

Q. IS THE CONDUCTOR AND CABLE IDENTIFIED IN TABLE 64 THE SMALLEST CONDUCTOR AND CABLE USED FOR NEW AND/OR REPLACEMENT APPLICATIONS ON THE COMPANY'S SYSTEM?

A. Generally, yes. For overhead application, #2ACSR remains the minimum standard. For three-phase underground primary applications, the minimum standard continues to be 1/0 Alum. The conductors and cables listed in Table 64 are the smallest practical equipment for three-phase primary applications, because they provide the minimum capacity rating required for our tap-level system design, which is in the range of 150 – 200 amps. However, for single-phased underground primary applications, we have introduced a new, smaller minimum-size cable. We transitioned from 1/0 Alum to #2 Alum. Again, conductor and cable ratings within this range are consistent with the maximum ratings of other system components available within the electric utility industry.

Q. HOW DOES THE MATERIAL COST OF #2 ALUM CABLE COMPARE TO THE MATERIAL COST OF THE CABLE LISTED IN TABLE 64?

A. Generally, the material cost of #2 Alum cable is less than the cost of 1/0 Alum cable.

D. Transformers

Q. How did Engineering Organization establish the minimum-size TRANSFORMERS?

A. When determining minimum sizing requirements for many transformer applications, it is important to not only consider the ultimate continuous (steady-state) load expected, but also the impacts of intense, yet short-duration loads such as motor-starts, which can cause unacceptable voltage sags. Often times, we have found in residential applications that motor-start limitations will cause the need to size a transformer larger than what the steady-state peak load would otherwise require.

Q. ARE THE TRANSFORMERS IDENTIFIED IN TABLE 64 THE SMALLEST TRANSFORMERS USED FOR NEW AND/OR REPLACEMENT APPLICATIONS ON THE COMPANY'S SYSTEM?

A. The transformers identified in Table 64 are *smaller* than the minimum-size transformers that are presently designed into the Company's distribution system. The minimum-size transformers in Table 64 are 10 kVA for both overhead and padmounted. The current minimum-size transformer designed into the Company's distribution system is 15 kVA for single-phase overhead applications and 50 kVA for single-phase underground (padmounted) applications.

Q. WHY HAS THE COMPANY ADOPTED A LARGER TRANSFORMER INTO ITS DISTRIBUTION SYSTEM?

A. Even though the Company has purchased and installed smaller sized transformers over the years, we no longer purchase anything smaller than 15 kVA for overhead and 50 kVA for underground. We have found that the incremental costs for the larger units are offset by the savings due to reduced inventory. This is primarily due to reduced carrying costs and warehousing requirements. Additionally, savings can be found through not having to return to the location to upsize transformers as additional homes are built, or as existing customers install air conditioning or other typical improvements that increase electrical load.

Q. HOW DOES THE MATERIAL COST OF 15 KVA OVERHEAD AND 50 KVA PADMOUNTED TRANSFORMERS COMPARE TO THE 10 KVA TRANSFORMERS LISTED IN TABLE 64?

A. Generally, the material costs of both transformers are greater than the cost of the 10 kVA transformers listed in Table 64.

E. Secondary Services

Q. PLEASE DISCUSS THE CRITERIA CONSIDERED BY THE ENGINEERING ORGANIZATION IN ESTABLISHING THE MINIMUM-SIZE SERVICES IN THE MINIMUM SYSTEM STUDY.

A. In general, we have found the minimum-size service conductor to be deployed on the Company's distribution system is 200 amps. This minimum capacity is based on such factors as steady-state loading for modern residential applications.

Q. ARE THE SERVICES IDENTIFIED IN TABLE 64 THE SMALLEST SERVICES USED FOR NEW AND/OR REPLACEMENT APPLICATIONS ON THE COMPANY'S SYSTEM?

A. Yes. The services listed in Table 64 are the smallest practical equipment, because most homebuilders have gone to a minimum 200 amp service entrance panel to accommodate the home's initial and future needs. I also note that experience has shown that this is the minimum-sized conductor necessary to reduce visible voltage flicker caused by motor starts in modern residential appliances and central air conditioning units to an acceptable level.

F. Load-Carrying Capability

Q. WHAT IS THE LOAD-CARRYING CAPABILITY ASSUMED IN THE MINIMUM SYSTEM STUDY?

A. The Minimum System Study assumes the minimum-size distribution equipment used in the Minimum System Study has load-carrying capability of 1.5 kW per customer.

Q. PLEASE DISCUSS THE CRITERIA CONSIDERED BY THE ENGINEERING ORGANIZATION IN ESTABLISHING THE PER-CUSTOMER LOAD-CARRYING CAPABILITY IN THE MINIMUM SYSTEM STUDY.

A. The load-carrying capability of 1.5 kW is based on the minimum load available from the minimum-size equipment used for the Minimum System Study.

Q. CAN YOU GIVE AN EXAMPLE OF WHAT TYPE OF RESIDENTIAL APPLIANCES AND/OR OTHER DEVICES WOULD OPERATE AT A LOAD OF 1.5 KW?

A. Yes. Based on typical wattages for modern residential appliances, operating the following items simultaneously would result in a load of 1.5 kW:

- A microwave oven and a refrigerator / freezer;
- A toaster and a television; or
- A coffee maker and an AM/FM radio.

Q. ARE THE ASSUMPTIONS IN THE MINIMUM SYSTEM STUDY REASONABLE?

A. Yes. The minimum-size equipment assumptions used in the Company's Minimum System Study reasonably approximate the minimum-size equipment currently being installed on the Company's system, or in some cases, such as transformers, slightly underestimate the minimum-size equipment.

G. 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 last 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 2016-2018.

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 historic 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 11,965 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. THE COST DATA USED IN THE ANALYSIS INCLUDED DATA FROM 2007-2018, 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.

IX. DISTRIBUTION SYSTEM LOSSES

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

A. In its June 12, 2017 Order in the last 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.[34] 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

[34] *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).

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.

Table 65

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 distribution system is not equipped with AMI, or any other equipment with similar data collection and communication capabilities. I discuss the functionalities and costs of the AMI and FAN technologies in more detail in Section IV of my testimony.

To collect substation level data, the Company would need Supervisory Control and Data Acquisition (SCADA) technology at each distribution substation. As of November 2019, approximately 102 of the Company's 240 distribution substations in Minnesota have SCADA functionality. Another 50 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 much further in the future or approximately 15 years from today.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Distribution capital investments and O&M budget presented in this rate case. These 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 28 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 construction 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

<u>Education</u>:

Bachelor of Science Electrical Engineering
South Dakota State University

<u>Employment</u>:

Xcel Energy Services

2015-Present	Vice President, Distribution Operations NSPM
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	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	11662320	Tap Cable Injection	(80.45)	(0.01)	-
CAPACITY	A.0000226.009	SUB Plymouth-Area Power Grid Upgrad	-	(12,464,926.37)	-
CAPACITY	A.0000226.010	LINES Hollydale Feeder Install	-	(6,221,593.46)	-
CAPACITY	A.0000390.014	LINE Install Wilson WIL TR4 & Feede	-	(9,487,780.20)	-
CAPACITY	A.0000390.015	SUB Install Wilson WIL TR4 & Feeder	-	(8,252,961.84)	-
CAPACITY	A.0000718.003	LINE Install Stockyards STY TR3 & F	-	-	(3,953,411.66)
CAPACITY	A.0000718.004	SUB Install Stockyards STY TR3 & Fd	-	-	(3,624,386.19)
NEW BUSINESS	A.0005500.028	Edina-Oh Extension	(2.02)	(0.01)	-
NEW BUSINESS	A.0005501.001	MNUG Extension-MN	(919.14)	(1.99)	-
NEW BUSINESS	A.0005501.044	South Dakota/MN - UG Extension	1.38	-	-
CAPACITY	A.0005502.016	LINE Install Feeder Tie CRL033	-	-	(1,142,341.86)
CAPACITY	A.0005502.023	Install Kohlman Lake KOL Feeder	-	(1,614,018.35)	-
CAPACITY	A.0005502.024	LINE Install Wyoming WYO Feeder	-	(1,918,575.70)	-
CAPACITY	A.0005502.082	Mntka-Oh Reinforcements	(70.78)	(2.42)	-
CAPACITY	A.0005502.083	Edina-Oh Reinforcements	194.31	6.35	-
CAPACITY	A.0005502.090	St Paul-Oh Reinforcements	466.63	15.26	-
CAPACITY	A.0005503.021	Install Baytown BYT Feeders	-	-	(4,414,837.78)
CAPACITY	A.0005503.058	Maple Grv-Ug Reinforcements	937.02	5.36	-
CAPACITY	A.0005503.061	Newport-Ug Reinforcements	(12.78)	(0.08)	-
CAPACITY	A.0005503.063	St Paul-Ug Reinforcements	81.58	0.46	-
CAPACITY	A.0005503.156	LINE Install Chemolite CHE065 Feede	-	(901,567.26)	-
NEW BUSINESS	A.0005504.001	MNOH Services-MN	(3.83)	-	-
NEW BUSINESS	A.0005505.001	MNUG Services-MN	65.55	0.04	-
NEW BUSINESS	A.0005506.001	MNOH Street Lights-MN	(130.52)	-	-
NEW BUSINESS	A.0005507.001	MNUG Street Lights-MN	0.04	-	-
ASSET HEALTH & RELIABILITY	A.0005508.001	MNOH Rebuilds-MN	(423.23)	(0.10)	-
ASSET HEALTH & RELIABILITY	A.0005508.028	Northwest - Overhead Rebuilds	(102.96)	(0.02)	-
ASSET HEALTH & RELIABILITY	A.0005508.081	North Dakota/MN - OH Rebuilds	235.78	0.05	-
ASSET HEALTH & RELIABILITY	A.0005509.001	MNUG ConvrsnsRebuilds-MN	7,246.41	5.54	-
ASSET HEALTH & RELIABILITY	A.0005509.013	ELR STP Vault Tops	(654,689.19)	(684,776.83)	(511,851.26)
ASSET HEALTH & RELIABILITY	A.0005509.014	ELR MPLS Vault Tops	(73.57)	(737,521.21)	(584,781.20)
ASSET HEALTH & RELIABILITY	A.0005509.105	Replace 7 CM2 Network Protecto	(3,698.56)	(54.06)	(0.77)
ASSET HEALTH & RELIABILITY	A.0005512.008	MPLS UG Network Vault Blanket	(465,581.92)	(476,880.36)	(488,249.16)
ASSET HEALTH & RELIABILITY	A.0005512.012	STP UG Network Vault Blanket	(230,899.34)	(236,549.78)	(242,232.14)
FLEET, TOOLS & COMM	A.0005516.030	Scrap Sale Credits-MN	(38.31)	-	-
CAPACITY	A.0005517.023	Substation Land - MN	(110.45)	(0.07)	(0.01)
ASSET HEALTH & RELIABILITY	A.0005518.003	NSPM-Poor Perf Fdr Replace Blk	16.35	0.01	-
ASSET HEALTH & RELIABILITY	A.0005518.052	REMS-Maple Grove	(0.23)	(0.01)	-

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0005521.001	MN Failed Sub Equip Replacement	(2,162,471.74)	(2,139,017.98)	(2,139,000.01)
ASSET HEALTH & RELIABILITY	A.0005521.014	SPCC NSPM Oil Spill Prevention	(672,571.32)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.015	MN Infratructure Invest - Sub	(4,691.21)	(1,410.40)	(594.57)
ASSET HEALTH & RELIABILITY	A.0005521.051	ELR MN Sub Feeder Breakers	(397,252.34)	(2,211,012.49)	(1,492,777.24)
ASSET HEALTH & RELIABILITY	A.0005521.052	ELR MN Sub Switches	(34,184.85)	(143,203.00)	(101,617.44)
ASSET HEALTH & RELIABILITY	A.0005521.091	ELR MN Sub Relays	(90,245.03)	(429,599.03)	(304,852.24)
ASSET HEALTH & RELIABILITY	A.0005521.092	ELR MN Sub Regulators	(80,780.63)	(286,415.98)	(203,234.85)
ASSET HEALTH & RELIABILITY	A.0005521.093	ELR MN Sub Fences	(72,212.23)	(358,000.81)	(254,043.59)
ASSET HEALTH & RELIABILITY	A.0005521.094	ELR MN Sub TRs	-	-	(873,257.12)
ASSET HEALTH & RELIABILITY	A.0005521.095	Reserve 26/13kV 28 MVA XFMR-MN	-	-	(513,151.62)
ASSET HEALTH & RELIABILITY	A.0005521.096	SUB Replace Fifth Street FST Switch	(7,564,590.01)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.103	ELR MN Sub Retirements	(55,515.13)	(286,395.61)	(203,234.84)
ASSET HEALTH & RELIABILITY	A.0005521.129	Rewind/Replace Failed Transfor	(7,994.46)	(582.08)	(42.25)
ASSET HEALTH & RELIABILITY	A.0005521.131	reserve 70 MVA 115/34.5 kV tra	(744,000.00)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.212	Replace Failed Substation Transform	(659,127.21)	(1,406,772.63)	(1,498,198.90)
CAPACITY	A.0005522.001	Dist Subs Capacity WCF-NSPM	-	(685,805.90)	(2,402,293.80)
CAPACITY	A.0005522.005	Minnesota-Sub Capac Reinforcem	(87,844.46)	(99,669.29)	(99,683.05)
CAPACITY	A.0005522.033	SUB Reinforce Fair Park FAP TR1 & F	(970,304.11)	-	-
CAPACITY	A.0005522.195	SUB Install Rosemount RMT TR2 & Fee	(3,768,005.43)	-	-
CAPACITY	A.0005522.277	SUB Install Wyoming WYO Feeder	-	(503,890.13)	-
CAPACITY	A.0005522.279	SUB Install Chemolite CHE065 Feeder	-	(543,995.79)	-
CAPACITY	A.0005522.281	Reinforce SCL TR2 to 70MVA	(2,940,275.81)	-	-
FLEET, TOOLS & COMM	A.0005549.006	NSPM-Dist Sub Communication Eq	(9,140.52)	(7.35)	(0.01)
ASSET HEALTH & RELIABILITY	A.0005549.020	ELR MN Sub RTUs	(29,310.07)	(149,595.22)	(106,156.47)
ASSET HEALTH & RELIABILITY	A.0005550.002	NSPM-Accelerated URD Cable Rep	1,145.21	16.07	-
ASSET HEALTH & RELIABILITY	A.0005550.005	NSPM-Accelerated URD Cable Rep	12.07	-	-
FLEET, TOOLS & COMM	A.0005553.001	Fiber Communication Cutover -	(195,120.48)	(435,445.46)	(673,977.10)
FLEET, TOOLS & COMM	A.0005560.002	VAR Network Devices	(1,003.29)	-	-
SOLAR	A.0005566.014	Aurora Solar Sub Reinforcement	375.58	104.22	28.92
SOLAR	A.0005566.015	SE Solar Garden Extensions - E	(2,767,041.32)	(201,470.08)	(14,624.39)
SOLAR	A.0005566.017	Extend facilities to serve NW	(351,665.87)	(25,597.73)	(1,857.65)
SOLAR	A.0005566.018	Solar Garden Ext Newport - Ext	-	-	3,185,751.25
SOLAR	A.0005566.020	Solar Gardens Communications - CSG	(37,757.75)	(2,749.16)	(199.56)
SOLAR	A.0005566.021	MN-Solar Garden Sub Comm	(54,036.86)	(3,933.84)	(285.52)
SOLAR	A.0005566.022	MN-Solar Garden Sub Work	(647,806.83)	(194,386.62)	(58,180.87)
SOLAR	A.0005566.023	Solar Garden Ext - WBL	(176,360.78)	(12,840.94)	(932.09)
SOLAR	A.0005566.025	Northwest Solar Gardens Ext	-	-	2,758,785.67
SOLAR	A.0005566.026	Solar Garden Ext - Shorewood	202,559.90	13,919.81	956.57
SOLAR	A.0005566.027	Solar Garden Ext - Edina	(14,289.29)	(1,040.06)	(75.48)
SOLAR	A.0005566.028	Solar Garden Ext - MPLS	(4,616.94)	(336.17)	(24.40)
ASSET HEALTH & RELIABILITY	A.0005585.001	MINNESOTA MAJOR STORM RECOVERY	584,294.17	448.04	-
FLEET, TOOLS & COMM	A.0005585.003	NSM - MN CAPITALIZED ELECTRIC LOCA	(404,579.83)	(400,003.50)	(400,000.01)

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0005585.004	MN Mixed Work Adjustment	(8,062,596.00)	(10,481,376.00)	(10,481,376.00)
FLEET, TOOLS & COMM	A.0006059.002	MN-Dist Electric Tools and Equip	(782,491.08)	(1,158,639.42)	(1,158,639.42)
FLEET, TOOLS & COMM	A.0006059.003	ND-Dist Electric Tools and Equip	(52,625.15)	(69,883.06)	(69,883.06)
FLEET, TOOLS & COMM	A.0006059.004	SD-Dist Dist Tools and Equip	(75,917.76)	(100,938.42)	(100,938.42)
FLEET, TOOLS & COMM	A.0006059.014	MN-Dist Subs Tools and Equip	(258,897.58)	(462,592.57)	(496,399.39)
FLEET, TOOLS & COMM	A.0006059.020	MN-DistLogistics	(104,263.52)	(172,765.98)	(185,678.54)
FLEET, TOOLS & COMM	A.0006059.021	SD-Dist Logistics	(3,482.23)	(4,352.78)	(4,352.78)
FLEET, TOOLS & COMM	A.0006059.024	MN-Dist Tools Common	(48,388.60)	(77,102.84)	(87,431.41)
FLEET, TOOLS & COMM	A.0006059.473	Logistics - NSPM - Tools - ND	(7,551.86)	(13,337.74)	(14,344.26)
FLEET, TOOLS & COMM	A.0006059.474	Nspm Metering Sys-Tools & Equi	(34,509.73)	(69,019.47)	(69,019.47)
FLEET, TOOLS & COMM	A.0006059.477	Logistics - Fencing - NSPM	(5,299.98)	(8,262.71)	(8,766.02)
FLEET, TOOLS & COMM	A.0006059.478	Logistics - Security Equipment	(16,362.36)	(28,269.12)	(34,058.33)
FLEET, TOOLS & COMM	A.0006059.479	Logistics Security Eqiupment N	(5,034.57)	(8,262.51)	(8,766.02)
NEW BUSINESS	A.0006062.001	Distribution CIAC MN Elec	3,733,000.00	3,702,000.00	3,813,000.00
NEW BUSINESS	A.0010003.001	MN - OH Extension Blanket	(3,205,655.32)	(3,618,136.46)	(3,650,997.74)
NEW BUSINESS	A.0010003.002	MN - UG Extension Blanket	(19,496,373.27)	(21,133,978.85)	(21,498,205.43)
NEW BUSINESS	A.0010003.003	MN - OH New Services Blanket	(2,229,455.56)	(2,746,603.91)	(2,787,909.90)
NEW BUSINESS	A.0010003.004	MN - UG New Services Blanket	(8,116,058.18)	(9,135,122.14)	(9,246,914.28)
NEW BUSINESS	A.0010003.005	MN - OH New Street Light Blanket	(360,976.13)	(361,320.38)	(370,388.18)
NEW BUSINESS	A.0010003.006	MN - UG New Street Light Blanket	(728,878.94)	(745,976.97)	(765,923.13)
CAPACITY	A.0010003.007	MN - New Business Network Blanket	(1,232,000.00)	(1,261,793.00)	(1,292,546.00)
MANDATES	A.0010011.001	MN - OH Relocation Blanket	(7,444,549.18)	(7,451,840.49)	(7,451,841.00)
MANDATES	A.0010011.002	MN - UG Relocation Blanket	(5,060,457.54)	(5,159,229.66)	(5,159,230.00)
MANDATES	A.0010011.003	MN - UG Service Conversion Blanket	(566,718.75)	(587,348.65)	(587,349.00)
MANDATES	A.0010011.004	MN - Mandate WCF Blanket	(1,932,892.37)	(3,739,880.81)	(3,739,247.15)
ASSET HEALTH & RELIABILITY	A.0010019.001	MN - OH Rebuild Blanket	(8,302,858.41)	(8,967,162.52)	(9,175,079.68)
ASSET HEALTH & RELIABILITY	A.0010019.002	MN - UG Conversion/Rebuild Blanket	(5,831,219.27)	(6,516,178.44)	(6,667,444.82)
ASSET HEALTH & RELIABILITY	A.0010019.003	MN - OH Services Renewal Blanket	(86,711.25)	(92,777.64)	(94,557.28)
ASSET HEALTH & RELIABILITY	A.0010019.004	MN - UG Services Renewal Blanket	(2,919,771.21)	(2,799,073.42)	(2,863,909.96)
ASSET HEALTH & RELIABILITY	A.0010019.005	MN - OH Street Light Rebuild Blanke	(566,596.88)	(606,602.74)	(621,772.35)
ASSET HEALTH & RELIABILITY	A.0010019.006	MN - UG Street Light Rebuild Blanke	(654,185.24)	(605,903.18)	(621,651.96)
ASSET HEALTH & RELIABILITY	A.0010019.007	MN - Network Renewal Blanket	(7,653.45)	(16.66)	(0.03)
ASSET HEALTH & RELIABILITY	A.0010019.008	MN - Pole Blanket	(25,447,453.55)	(16,584,625.12)	(15,682,420.32)
ASSET HEALTH & RELIABILITY	A.0010019.009	MN - Line Asset Health WCF Blanket	(6,173,317.44)	(9,632,830.45)	(9,742,415.20)
MANDATES	A.0010019.010	MN - Pole Transfer (3rd Party) Blan	(461,559.45)	(440,005.26)	(440,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.001	MN - URD Cable Replacement Blanket	(15,092,000.00)	(25,578,000.00)	(21,560,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.002	MN - Feeder Cable Replacement Blank	(4,900,000.00)	(4,900,000.00)	(4,900,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.003	MN - REMS Blanket	(499,800.00)	(1,166,200.00)	(833,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.004	MN - FPIP Blanket	(588,000.00)	(1,372,000.00)	(1,470,000.00)
CAPACITY	A.0010035.001	MN - OH Reinforcement Blanket	(830,905.00)	(830,905.00)	(830,905.00)
CAPACITY	A.0010035.002	MN - UG Reinforcement Blanket	(455,402.00)	(455,402.00)	(455,402.00)
CAPACITY	A.0010035.004	MN - Line Capacity WCF Blanket	-	(298,011.67)	(763,047.87)

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
CAPACITY	A.0010061.004	Load Transfer CGR062 to CGR071	(966,740.27)	-	-
MANDATES	A.0010069.003	MPLS Mandates WCF	(1,611,601.42)	(2,402,785.93)	(7,592,406.15)
NEW BUSINESS	A.0010069.004	MN LED Post Top Conversion	(1,000,000.00)	(1,000,000.00)	(1,000,000.00)
MANDATES	A.0010069.012	Relocation Hwy 35 106th St to Cliff	-	328,240.91	-
ASSET HEALTH & RELIABILITY	A.0010077.001	Replace Fifth Street FST Network RT	(194,920.61)	-	-
ASSET HEALTH & RELIABILITY	A.0010077.012	Rebuild Clara City CLC221	-	(2,220,077.41)	-
ASSET HEALTH & RELIABILITY	A.0010077.022	T Rebuild West St Cloud to Millwood	-	-	(5,451,608.08)
ASSET HEALTH & RELIABILITY	A.0010077.024	Rebuild Sacred Heart SCH211	(2,044,132.60)	-	-
CAPACITY	A.0010093.008	TER065, extend TER073 to provide lo	(21,883.36)	-	-
CAPACITY	A.0010093.010	Extend Main Street MST074	(300,645.01)	-	-
CAPACITY	A.0010093.015	LINE Reinforce Westgate WSG Feeders	(250,708.70)	-	-
CAPACITY	A.0010093.017	Install Feeder Tie EBL064	-	(149,485.32)	-
CAPACITY	A.0010093.019	Install Feeder Tie Wilson WIL081	(299,351.29)	-	-
CAPACITY	A.0010093.023	Add 3rd feeder to Goodview Bank #2	-	(571,979.66)	-
CAPACITY	A.0010093.024	Install new feeder tie from FAP	(386,389.02)	-	-
CAPACITY	A.0010093.028	LINE Reinforce Kasson KAN TR1 & Fee	-	-	(337,134.86)
CAPACITY	A.0010093.031	Load Transfer ESW062 to SMT061	(95,459.39)	-	-
CAPACITY	A.0010093.038	Reinforce Osseo OSS062	(199,443.89)	-	-
CAPACITY	A.0010093.044	LINE Install Albany ALB TR	-	-	(96,121.35)
CAPACITY	A.0010093.048	LINE Install Fiesta City FIC Feeder	-	(477,251.18)	-
CAPACITY	A.0010093.065	Install Feeder Tie Osseo OSS063	(99,783.76)	-	-
CAPACITY	A.0010093.070	LINE Reinforce Veseli VES TR1 & Fee	-	-	(334,767.96)
CAPACITY	A.0010093.071	Reinforce Basset Creek BCR062	-	(250,670.65)	-
CAPACITY	A.0010093.072	Extend Red Rock RRK063	(95,452.31)	-	-
CAPACITY	A.0010093.074	Reinforce Glenwood GLD Sub Equip	-	(703,119.43)	-
CAPACITY	A.0010093.076	LINE Reinforce Medford Junction MDF	(960,008.86)	-	-
CAPACITY	A.0010093.077	Extend Saint Louis Park SLP092	-	(609,059.57)	-
CAPACITY	A.0010093.078	LINE Install Midtown MDT Feeder	-	(1,421,139.05)	-
CAPACITY	A.0010093.079	Install Feeder Tie SOU083 to MDT074	-	(101,509.96)	-
CAPACITY	A.0010093.081	Reinforce Terminal TER073	-	-	(1,117,271.40)
CAPACITY	A.0010093.082	Extend Saint Louis Park SLP085	(152,643.21)	-	-
CAPACITY	A.0010093.083	Reinforce Moore Lake MOL071	-	(558,304.63)	-
CAPACITY	A.0010093.086	Reinforce Medicine Lake MEL074	(508,810.67)	-	-
CAPACITY	A.0010093.087	LINE Install Hiawatha West HWW Feed	(712,334.93)	-	-
CAPACITY	A.0010093.088	Reinforce Saint Louis Park SLP087	-	(152,264.90)	-
CAPACITY	A.0010093.089	Install Switch Coon Creek CNC073	(29,018.63)	-	-
CAPACITY	A.0010093.090	LINE Install Rosemount RMT TR2 & Fe	(822,170.18)	-	-
CAPACITY	A.0010101.001	SUB MN Feeder Load Monitoring	(850,825.38)	(1,880,579.09)	(2,436,069.03)
FLEET, TOOLS & COMM	A.0010101.002	COMM MN Feeder Load Monitoring	(356,672.79)	(669,020.94)	(857,305.75)
FLEET, TOOLS & COMM	A.0010101.006	COMM Revenue Metering to Mapleton	(220,589.23)	-	-
FLEET, TOOLS & COMM	A.0010101.007	T Revenue Metering Minnesota Lake	(209,919.07)	-	-
ASSET HEALTH & RELIABILITY	A.0010125.002	Replace End of Life Substation Batt	(52,698.36)	(257,757.27)	(182,911.32)

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0010125.014	ELR MPLS Network Protectors	(268,754.76)	(680,373.93)	(934,270.67)
ASSET HEALTH & RELIABILITY	A.0010125.015	ELR STP Network Protectors	(311,178.20)	(680,384.86)	(934,270.67)
ASSET HEALTH & RELIABILITY	A.0010125.016	Replace Linde LND TR1	(2,060,335.98)	-	-
ASSET HEALTH & RELIABILITY	A.0010125.020	Reserve XFMR 115-13.8 kV at 70 MVA	(514,797.27)	-	-
CAPACITY	A.0010133.007	SUB Reinforce Westgate WSG Feeders	(301,515.93)	-	-
CAPACITY	A.0010133.011	Install Breaker for New Goodview Ba	-	(502,352.30)	-
CAPACITY	A.0010133.016	SUB Reinforce Kasson KAN TR1 & Feed	-	-	(2,523,080.47)
CAPACITY	A.0010133.033	SUB Install Albany ALB TR	-	-	(2,846,874.78)
CAPACITY	A.0010133.038	SUB Install Fiesta City FIC Feeder	-	(502,353.58)	-
CAPACITY	A.0010133.055	SUB Install Feeder Tie CRL033	-	-	(50,076.09)
CAPACITY	A.0010133.063	Reinforce Savage SAV063 & SAV067	(1,122,935.84)	-	-
CAPACITY	A.0010133.064	SUB Reinforce Medford Junction MDF	(1,685,074.28)	-	-
CAPACITY	A.0010133.065	SUB Reinforce Veseli VES TR1 & Feed	-	-	(2,437,165.04)
CAPACITY	A.0010133.066	T Reinforce Red Rock RRK TR2	(865,433.04)	-	-
CAPACITY	A.0010133.067	Install Hiawatha West HWW TR2	-	-	(1,590,036.42)
CAPACITY	A.0010133.070	SUB Install Midtown MDT Feeder	-	(507,549.67)	-
CAPACITY	A.0010133.071	SUBS New Substation for Airgas	(2,849,339.70)	-	-
CAPACITY	A.0010133.072	SUB Install Hiawatha West HWW Feede	(508,810.67)	-	-
MANDATES	A.0010143.002	Relocation EDINA SWLRT Road Project	-	-	(2,349,124.45)
MANDATES	A.0010143.005	Relocation MPLS SWLRT Road Project	-	-	(3,543,828.22)
MANDATES	A.0010143.006	COMP Relocation EDINA SWLRT Road Pr	-	-	1,389,378.98
MANDATES	A.0010143.007	COMP Relocation MPLS SWLRT Road Pro	-	-	1,382,228.91
CAPACITY	A.0010144.002	Crosstown new 13.8kv Sub(REPLACED)	-	(208,161.81)	-
ASSET HEALTH & RELIABILITY	A.0010145.002	LINE Replace Fifth Street FST Switc	(854,677.56)	-	-
CAPACITY	A.0010148.002	Install new South Washington ERU Su	(5,902,148.43)	-	-
CAPACITY	A.0010148.003	Install New Fdrs - South Washington	(503,498.02)	-	-
FLEET, TOOLS & COMM	A.0010148.004	COMM Install South Washington ERU S	(86,653.17)	-	-
CAPACITY	A.0010149.001	SUB Install Western WES TR3 & Feede	-	-	(4,081,660.82)
CAPACITY	A.0010149.002	LINE Install Western WES TR3 & Feed	-	-	(1,402,130.53)
ASSET HEALTH & RELIABILITY	A.0010151.001	YLM211 and YLM212 Rebuild OH lines	-	-	(4,131,951.98)
MANDATES	A.0010154.001	VAULT Relocation 4th Street Road Pr	-	(571,464.53)	-
MANDATES	A.0010154.002	LINE Relocation 4th Street Road Pro	-	(7,601,627.45)	-
CREMENTAL SYSTEM INVESTME	A.0010162.003	MN Incremental System Investment	-	(50,678,063.39)	(84,022,979.27)
MANDATES	A.0010167.001	LINE Relocation Hennepin Ave Rd Pro	-	-	(11,475,386.78)
MANDATES	A.0010167.002	VAULT Relocation Hennepin Ave Rd Pr	(736,199.75)	-	-
ELECTRIC VEHICLE PROGRAM	A.0010180.001	MN Electric Vehicle Program	(9,824,077.10)	(8,310,160.74)	(10,098,761.52)
AGIS	D.0001723.046	GIS Cleanup for ADMS - NSPM	(1,743,793.59)	(871,788.29)	(871,814.20)
AGIS	D.0001900.016	FAN - AGIS - NSPM	(2,834,530.53)	(5,381,531.24)	(0.21)
AGIS	D.0001901.043	AMI-DIST-NSPM-MN Full AMI	-	(22,195,456.14)	(98,698,576.32)
AGIS	D.0001901.044	AMI-DIST-NSPM-MN TOU	(1,844,215.32)	-	-
AGIS	D.0001902.009	FLISR - AGIS - NSPM	(3,062,045.76)	(7,972,873.80)	(4,390,857.96)
AGIS	D.0001904.040	IVVO-Comm-Dist Blanket-NSPM	-	(4,096,092.93)	(5,876,285.01)

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
FLEET, TOOLS & COMM	D.0001907.026	AGIS-Planning & Fcst Tool-MN	(4,033,853.60)	-	-
AGIS	D.0001908.001	AGIS-Dist-Capital-Line-Contingency-	-	-	(2,002,580.52)
AGIS	D.0001908.002	AGIS-Dist-Capital-Subs-Contingency-	-	-	(838,500.84)
AGIS	D.0001908.038	AGIS-Dist-Capital-Line-AMI-Contin-N	-	-	(12,228,126.24)
AGIS	D.0001908.040	AGIS-Dist-Capital-Line-FLISR-Contin	-	-	(1,409,982.60)
NEW BUSINESS	D.0005014.004	MN Elec Distribution Transformers	(21,364,700.00)	(22,929,089.00)	(21,927,168.00)
NEW BUSINESS	D.0005014.021	MN-Electric Meter Blanket	(5,133,023.00)	(4,015,440.00)	(3,232,944.00)

Depreciation O&M Budget by Category NSPM-Electric (Dollars in Millions)							
NSPM Electric	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Forecast**	**2020 Budget**	**2021 Budget**	**2022 Budget**
Internal Labor	46.8	48.1	51.9	53.8	58.3	59.8	60.5
Contract Labor	42.9	46.2	49.5	55	48.4	54.9	53.5
Fleet	7.3	8.3	8.3	7.4	6.9	6.8	6.8
Materials	8.5	8.1	7	5.9	6.9	6.8	6.8
Other	-1.6	-2.4	0.1	-0.2	-3.9	-3.6	-3.6
Total*	**104**	**108.3**	**116.8**	**121.9**	**116.6**	**124.7**	**124**

**Includes O&M associated with the Company's ADMS deployment which we are seeking recovery of in the TCR rider.*

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
TOTAL - Communications	***422,543***	***2,748,494***	***5,408,226***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,579,263***	***7,309,033***
TOTAL CAPITAL	**3,737,070**	**6,055,686**	**31,617,795**	**120,132,290**	**113,025,244**	**11,069,690**	**2,417,435**	**2,491,719**	**2,568,285**	**2,647,205**	**2,728,549**	**2,812,393**	**2,898,813**	**2,987,889**	**3,079,701**	**3,174,336**	**3,271,878**	**316,715,976**	**233,789,195**
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
TOTAL - Communications	***0***	***0***	***190,831***	***434,922***	***395,356***	***328,021***	***154,164***	***78,678***	***55,118***	***56,259***	***57,424***	***58,612***	***59,826***	***61,064***	***62,328***	***63,618***	***64,935***	***2,121,155***	***1,400,602***
AMI Operations (Personnel)																			
	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	0	219,920	291,008	636,082	1,916,255	1,558,818	1,681,704	2,903,750	3,026,581	3,134,024	3,245,282	3,360,490	3,479,787	3,603,319	3,731,237	3,863,696	4,000,857	***40,652,811***	***20,218,244***
TOTAL O&M	**0**	**219,920**	**481,839**	**1,071,003**	**2,311,611**	**1,886,839**	**1,835,869**	**2,982,428**	**3,081,699**	**3,190,283**	**3,302,706**	**3,419,102**	**3,539,613**	**3,664,383**	**3,793,565**	**3,927,314**	**4,065,792**	**42,773,966**	**21,618,846**
GRAND TOTAL CAPITAL & O&M	**3,737,070**	**6,275,606**	**32,099,634**	**121,203,293**	**115,336,855**	**12,956,529**	**4,253,304**	**5,474,147**	**5,649,984**	**5,837,488**	**6,031,254**	**6,231,494**	**6,438,425**	**6,652,272**	**6,873,267**	**7,101,650**	**7,337,670**	**359,489,942**	**255,408,042**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
CAPITAL ITEMS - SUMMARY																						
FLISR Assets																						
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	**42,546,523**
Communications Network																						
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**
TOTAL - Communications	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***1,227,893***	**1,046,094**
TOTAL CAPITAL	**60,476**	**3,526,882**	**9,183,048**	**6,282,593**	**9,050,018**	**8,441,837**	**6,339,229**	**6,489,497**	**6,643,552**	**6,801,496**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**62,818,628**	**43,592,617**
O&M ITEMS - SUMMARY																						
Deployment																						
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	**1,025,692**
Ongoing Support																						
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	**3,091,849**
Communications Network																						
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M	**0**	**117,199**	**319,890**	**255,232**	**371,660**	**435,164**	**430,123**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,213,663**	**4,117,541**
GRAND TOTAL CAPITAL & O&M	**60,476**	**3,644,080**	**9,502,937**	**6,537,826**	**9,421,678**	**8,877,001**	**6,769,352**	**6,968,353**	**7,172,977**	**7,383,381**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**71,032,291**	**47,710,158**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Continguency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	**16,857,896**
Communications Network																						
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
TOTAL - Communications	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***409,298***	**348,698**
TOTAL CAPITAL	**20,159**	**234,675**	**4,029,031**	**6,302,808**	**6,471,034**	**5,798,235**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**22,855,942**	**17,206,594**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	**92,683**
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	**1,179,310**
Communications Network																						
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	**0**
TOTAL O&M	**0**	**0**	**17,731**	**37,764**	**56,373**	**107,475**	**116,604**	**161,991**	**166,212**	**170,551**	**175,011**	**179,597**	**184,312**	**189,161**	**194,146**	**199,272**	**204,544**	**209,965**	**215,541**	**221,276**	**2,807,527**	**1,271,993**
GRAND TOTAL CAPITAL & O&M	**20,159**	**234,675**	**4,046,762**	**6,340,573**	**6,527,407**	**5,905,710**	**116,604**	**161,991**	**166,212**	**170,551**	**175,011**	**179,597**	**184,312**	**189,161**	**194,146**	**199,272**	**204,544**	**209,965**	**215,541**	**221,276**	**25,663,468**	**18,478,587**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	***0***	***0***	***0***	***0***	***629,401***	***1,611,661***	***2,634,487***	***2,893,232***	***2,995,942***	***3,217,567***	***3,331,791***	***3,450,070***	***3,572,547***	***3,699,373***	***3,830,700***	***3,966,690***	***4,107,508***	***39,940,969***	***19,299,262***
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	***0***	***0***	***0***	***0***	***1,159***	***2,401***	***4,972***	***5,148***	***5,331***	***5,520***	***5,716***	***5,919***	***6,129***	***6,347***	***6,572***	***6,805***	***7,047***	***69,067***	***33,431***
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	***0***	***0***	***0***	***0***	***604***	***1,250***	***2,589***	***2,681***	***2,776***	***2,875***	***2,977***	***3,082***	***3,192***	***3,305***	***3,422***	***3,544***	***3,670***	35,965	17,409
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**631,163**	**1,615,312**	**2,642,048**	**2,901,061**	**3,004,049**	**3,225,962**	**3,340,484**	**3,459,071**	**3,581,868**	**3,709,024**	**3,840,695**	**3,977,039**	**4,118,224**	**40,046,001**	**19,350,101**
OTHER BENEFITS																			
Cost reductions																			
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
TOTAL - Cost Reductions	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	***21,103,587***	***10,323,309***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**391,289**	**798,777**	**1,630,623**	**1,664,377**	**1,698,830**	**1,733,996**	**1,769,889**	**1,806,526**	**1,843,921**	**1,882,090**	**1,921,050**	**1,960,815**	**2,001,404**	**21,103,587**	**10,323,309**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	***20,755***	***412,501***	***3,935,923***	***12,881,148***	***23,340,750***	***29,130,716***	***29,698,551***	***28,887,914***	***28,107,557***	***27,361,868***	***26,557,430***	***25,715,024***	***24,868,419***	***23,999,536***	***23,212,398***	***22,384,139***	***21,406,031***	***351,920,659***	***189,681,697***
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**26,893,572**	**34,784,729**	**38,245,438**	**37,871,584**	**37,377,819**	**37,043,689**	**36,549,676**	**36,028,238**	**35,513,521**	**34,987,835**	**34,555,606**	**34,094,385**	**33,495,880**	**475,992,333**	**250,858,601**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	**7,387,915**	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	**46,895,083**	**$22,349,410**

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Schedule 10 – Summary of Xcel Energy's Analysis Supporting AMI Meter Vendor Selection

Trade Secret Justification

Schedule 10 is an internal assessment summary that the Company has designated as Trade Secret information in its entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released. This summary was prepared by Major Products & Programs Sourcing employees and their representatives in 2019. This Schedule contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because this overall analysis derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret.

This presentation 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**: Internal assessment of responses to RFPs.
2. **Authors**: Major Products & Programs Sourcing employees and their representatives.
3. **Importance**: The Company's proprietary analysis of RFP responses.
4. **Date the Information was Prepared**: This assessment was prepared in second quarter of 2019.