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November 1, 2021

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/M-21-694

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Integrated Distribution Plan (IDP) per the Commission's July 23, 2020 Order in Docket No. E002/M-19-666.

This IDP outlines our distribution strategy, drivers, and goals. It provides historical actual and budgeted expenditures, outlines present and forecasted levels of Distributed Energy Resourecs (DER), details our planning practices, discusses the planning landscape within which we are anticipating and responding, and describes our advanced grid plans.

In addition, this IDP contains two initiatives we are seeking certification for pursuant to Minn. Stat. § 216B.2425:

(1) *Distributed Intelligence (DI)*. DI is the equivalent of a small computer in the smart meters we will soon begin deploying that can process data in real time at the meter – harnessing powerful capabilities that will help customers better understand and reduce energy usage, and help the Company detect and respond to issues on the distribution system in a way that advanced meters alone cannot.

The analytics made possible through DI have the potential to make customers more than just consumers of energy – giving them the capabilities and information to be active participants in their energy usage. With detailed information, customers can change their behavior in ways that promote energy efficiency and demand response, saving on energy bills while also providing benefits to all customers through grid benefits and carbon reductions. Similarly, DI analytics will extend the Company's advanced capabilities for the distribution system to enable more precise monitoring and control at the edge of the grid, enabling greater reliability and lower costs to customers for managing the system; and

(2) *The Resilient Minneapolis Project (RMP).* RMP is a proposed project at three Minneapolis locations in with Black, Indigenous, and People of Color (BIPOC)-led partner organizations that seeks to improve communities' resilience to crises while advancing the Commission's objectives for IDPs. The RMP will be implemented at three locations: (1) the North Minneapolis Community Resiliency Hub; (2) Sabathani Community Center; and (3) the Minneapolis American Indian Center.

At each site, the Company will work with partners to install rooftop solar, battery energy storage systems, microgrid controls, and necessary distribution system modifications to integrate these technologies. These systems will not only be managed with reserve capacity to provide power for critical services during electric system outages, but also dispatched and optimized daily to mitigate system peaks, manage and shape demand, and integrate more solar generation.

Portions of this IDP contain protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). See Attachment A to this filing for the trade secret justifications for each piece.

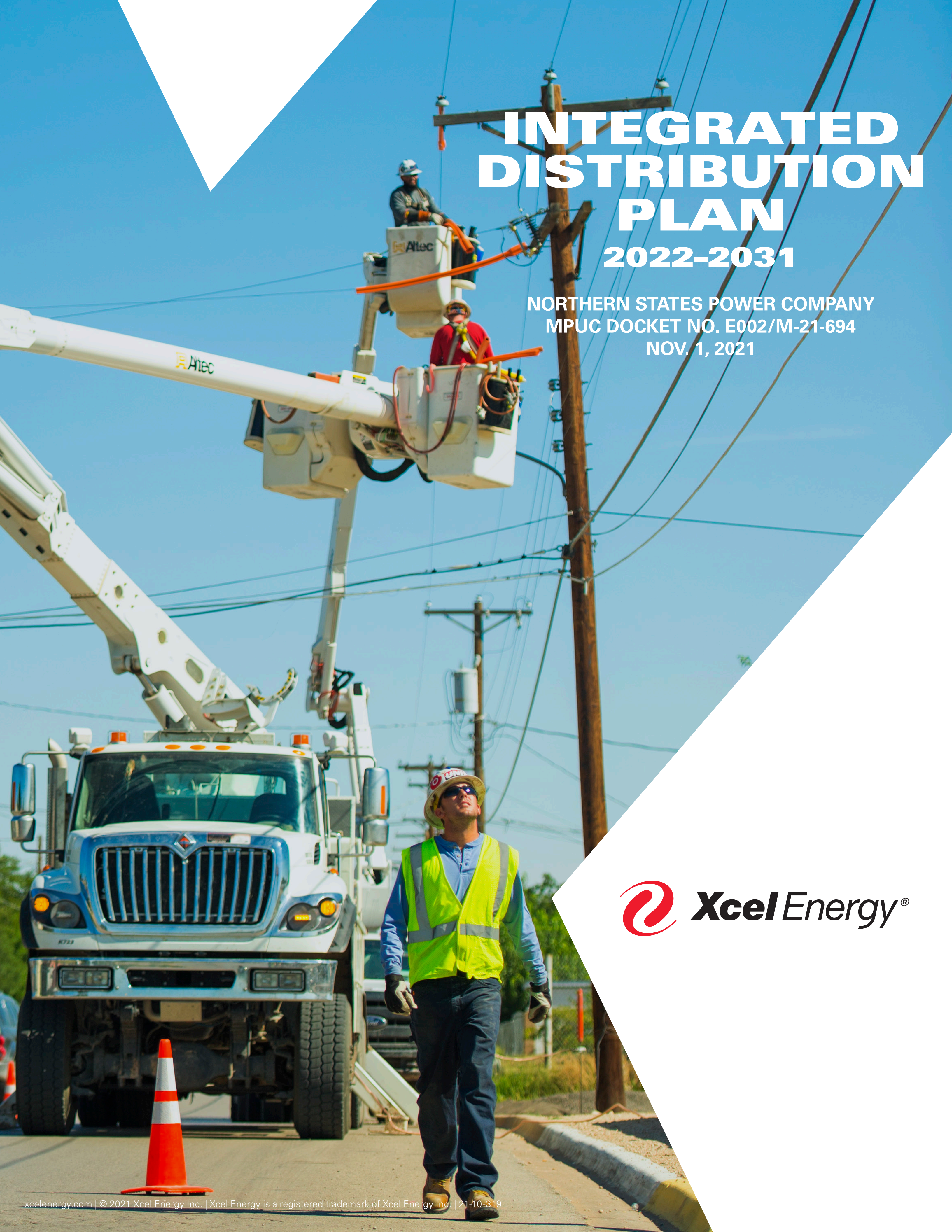
We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Jody Londo at jody.l.londo@xcelenergy.com or (612) 330-5601 or me at bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service Lists



INTEGRATED DISTRIBUTION PLAN

2022–2031

NORTHERN STATES POWER COMPANY
MPUC DOCKET NO. E002/M-21-694
NOV. 1, 2021

Xcel Energy®

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
BESS	Battery Energy Storage System
BTM	Behind the Meter
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CEE	Center for Energy and Environment
CEUD	Customer Energy Usage Data
CIP	Conservation Improvement Program
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CPE	Customer Premise Equipment
CPUC	California Public Utilities Commission
CRS	Customer Resource System
DCF	Discounted Cash Flow
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DG-PV	Photovoltaic Distributed Generation
DI	Distributed Intelligence
DOE	Department of Energy
DR	Demand Response
DRIVE	EPRI's Distribution Resource Integration and Value Estimation tool (for Hosting Capacity Analysis)
DRMS	Demand Response Management System
DSM	Demand Side Management
DSPx	DOE's Next Generation Distribution System Platform
EE	Energy Efficiency
EPRI	Electric Power Research Institute
ERT	Estimated Restoration Time
EV	Electric Vehicle
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FLP	Fault Location Prediction
GIS	Geospatial Information System
HAN	Home Area Network
HECO	Hawaiian Electric Company
HPUC	Hawaii Public Utilities Commission
IDP	Integrated Distribution Plan

IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
IT	Information Technology
MAIC	Minneapolis American Indian Center
MAIFI	Momentary Average Interruption Frequency Index
MBE	Minority Business Enterprise
MDMS	Meter Data Management System
MISO	Midcontinent Independent System Operator
MPS	Minneapolis Public Schools
MPUC, PUC, or Commission	Minnesota Public Utilities Commission
NIST	National Institute of Standards and Technology
NPV	Net Present Value
NSPM or Company	Northern States Power Company-Minnesota Operating Company
NWA	Non-Wire Alternatives
NYPSC	New York Public Service Commission
OMS	Outage Management System
PLC	Power Line Carrier
PSCo	Public Service Company of Colorado
PV	Photovoltaic
QSP	Quality of Service
RATC	Regional Apprenticeship Training Center
REP	Renewable Energy Partners
RFA	Request for Applications
RFP	Request for Proposals
RMP	Resilient Minneapolis Project
RTO	Regional Transmission Operator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEPA	Smart Electric Power Alliance
TCR	Transmission Cost Recovery Rider
TLM	Transformer Load Management
TOU	Time of Use
USDN	Urban Sustainability Directors Network
VEE	Validation, Estimation, Editing
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.

INTEGRATED DISTRIBUTION PLAN

EXECUTIVE SUMMARY

For more than a century, Xcel Energy has provided highly reliable, safe, and affordable power to millions of customers in eight states across the United States. We are proud of the system we have designed and built over many decades and of the contributions our employees have had in fueling the growth in American industry and commerce through affordable power.

That system is becoming cleaner, more flexible, and more decentralized – moving away from large, centrally-located fossil-fuel powered plants. In 2018, Xcel Energy announced its vision to serve customers with 100 percent carbon-free electricity by 2050, while achieving our other strategic priorities of keeping bills low and enhancing the customer experience. In 2020, we announced our plans to drive toward powering 1.5 million electric vehicles by 2030 which is 30 times the number on the road today.

For the distribution system, the clean and customer-driven energy revolution has necessitated a shift in our approach to planning and operations. Designing the system to achieve our ambitious vision and customers' increasing reliance on electric service, while maintaining the existing system and keeping costs low creates challenges as well as opportunities. We must be able to reliably deliver a cleaner mix of utility scale energy, integrate increasing amounts of carbon-reducing distributed energy resources and, at the same time, meet and efficiently integrate new levels of energy demand from electric vehicles and other beneficial electrification.

This Integrated Distribution Plan (IDP) provides an overview of our distribution system, strategy, and how we plan the system to meet our customers' current and future needs. The backbone of distribution planning is ensuring we have the right infrastructure in place to keep the lights on for our customers, safely and affordably. At the same time, we have a vision for where we and our customers want the grid to go. We are taking measured and thoughtful action to balance these key factors and ensure our customers receive the greatest value both now and over time, and that the fundamentals of our distribution business remain sound.

This IDP recognizes the emergent state of the industry, Minnesota's specific circumstances, and the building-block approach we are taking to modernize and equip our system to increase our visibility, control, and planning capabilities. Our report outlines our distribution strategy, drivers, and goals. It provides historical actual and budgeted expenditures, outlines present and forecasted levels of DER, details our planning practices, discusses the landscape within which we are operating our distribution system, and describes our advanced grid plans.

As we look out over the next five years and our distribution budgets, we have three strategic priorities: (1) addressing our aging assets; (2) enabling the clean energy transition; and (3) modernizing the grid. We are planning investments to support each of these priorities including an increased focus on asset health and reliability investments, investments in electronic reclosers to support DER, and investments in new AMI meters and supporting infrastructure to modernize the grid. Each of these priorities and our plans to support them are discussed below.

We also discuss below two specific initiatives for which we are seeking certification pursuant to Minn. Stat. § 216B.2425. Our first certification request is for investments we are making to take advantage of the Distributed Intelligence (DI) capabilities of the AMI meters we will soon be deploying. DI is the equivalent of a small computer in the meters that can process data in real time– providing the Company with powerful capabilities that we will use to help customers better understand and reduce energy usage, and help the Company detect and respond to issues on the distribution system in a way that AMI metering alone cannot. Our second certification request is for a Minneapolis Resiliency Project, which proposes to pilot various resilience initiatives at three specific community locations in Minneapolis with BIPOC-led partner organizations.

At the May 29, 2020 Commission Agenda Meeting, the Company Committed to highlight pieces of the current IDP that are new or have changed since our last IDP. First, we would like to call out that the 2021 IDP is being presented in a new format. We believe this new format will allow parties to more easily navigate to their areas of interest. Below we list the portions of this 2021 IDP filing that are either new or have significantly changed from our 2019 IDP filing. Please note, in addition to the areas highlighted below, several additional pieces of the IDP have been refreshed (such as the financial information provided in Appendix D).

New to 2021 IDP

- Appendix B3: Operational and Planning Data Management, Data Security, and Data Access Plans and Policies
- Appendix G: Distributed Intelligence Certification Request
- Appendix H: Resilient Minneapolis Project Certification Request
- Attachment K: PiE MN Goals for Generation Distribution and EV
- Attachment M: Firm Capability Statement

Substantially Changed

- Integrated Distribution Plan (main report)
- Appendix B1: Grid Modernization
- Appendix B2: Customer Strategy and Roadmap
- Appendix B4: Existing and Potential New Grid Modernization Pilots
- Appendix C: Action Plans
- Appendix F: Non-Wires Alternatives (NWA) Analysis

This report is designed to provide transparency into our distribution function and planning and complies with all regulatory and legislative requirements. We look forward to engaging with stakeholders in this docket concerning our distribution plans, and we request the Commission accept this IDP and grant certification of our proposed grid modernization initiatives.

I. INTEGRATED DISTRIBUTION PLAN BACKGROUND

In 2015, the Commission opened an investigatory docket on grid modernization (Docket No. E999/CI-15-556) and issued the *March 2016 Staff Report on Grid Modernization*. Among the potential options outlined in the Staff Report, the Commission supported examining distribution system planning as the most reasonable and actionable way to assist in the forthcoming grid evolution. In January 2018, Commission staff proposed next steps to the Commission at a planning meeting – and in April 2018, established individual utility dockets and released proposed individual utility IDP filing requirements for Commission review; requirements for Xcel Energy were developed in Docket No. E002/CI-18-251. On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an IDP annually beginning on November 1, 2018.

Accordingly, we submitted our first IDP November 1, 2018. Like the development of the IDP requirements themselves, the April 2018 Order acknowledged integrated distribution planning would be an iterative process – set in motion with the Company's initial IDP. The Commission accepted our first IDP, modified the filing requirements, and ordered that we submit our next IDP November 1, 2019. The amended requirements clarified the cost-benefit analysis requirements for grid modernization projects and several other additional content requirements. Additionally, in connection with our Transmission Cost Recovery rider proceeding in Docket No. E002/M-17-797, the Commission specified a number of requirements associated with cost recovery of future grid modernization proposals.

The Commission accepted the Company's 2019 IDP in Docket No. E002/M-19-666 in its July 23, 2020 Order – again modifying certain requirements and changing the IDP cadence to bi-annual, with the next full report due November 1, 2021, and requiring the Company to submit certain financial information and non-wires alternatives analysis in the off-years starting in 2020. The Commission further modified the IDP requirements for all utilities in a November 2, 2020 Order in Docket Nos. E111/M-19-674, E002/M-19-666, E015/M-19-684, and E017/M-19-693.

Leading up to this IDP, we held a stakeholder meeting on September 17, 2021 that provided stakeholders an overview and forum to ask questions and offer feedback on key aspects of this IDP including:

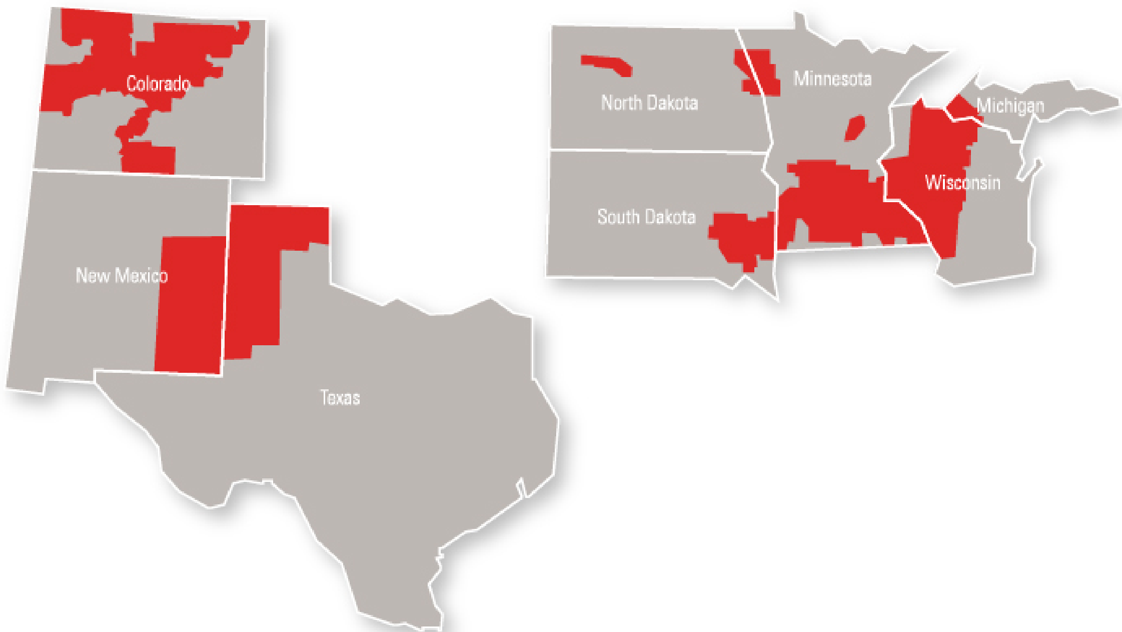
- Distribution system capital and operations & maintenance (O&M) budgets and trends;
- Distributed Energy Resource (DER) forecasts and methodologies;
- Non-Wires Alternatives (NWA) analysis;
- Advanced Grid plans; and
- Certification Requests for Distributed Intelligence and the Resilient Minneapolis Project.

Attachment B to this IDP provides a summary compliance table of the Commission's various Order Requirements that identifies the locations in this IDP where we provide the information responsive to each requirement. The various IDP requirements are also embedded throughout this IDP.

II. XCEL ENERGY OVERVIEW

Xcel Energy is a major U.S. electric and natural gas company based in Minneapolis, Minnesota. We have regulated utility operations in eight Midwestern and Western states – Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin – where we provide a comprehensive portfolio of energy-related products and services to approximately 3.6 million electricity customers and 2 million natural gas customers. Our Upper Midwest service area is part of an integrated system of generation and transmission made up of two operating companies – NSPM, which serves Minnesota, North Dakota and South Dakota; and Northern States Power Company–Wisconsin (NSPW), which serves Wisconsin and Michigan. These two operating companies are collectively referred to as the NSP System.

Figure 1: Xcel Energy Service Areas

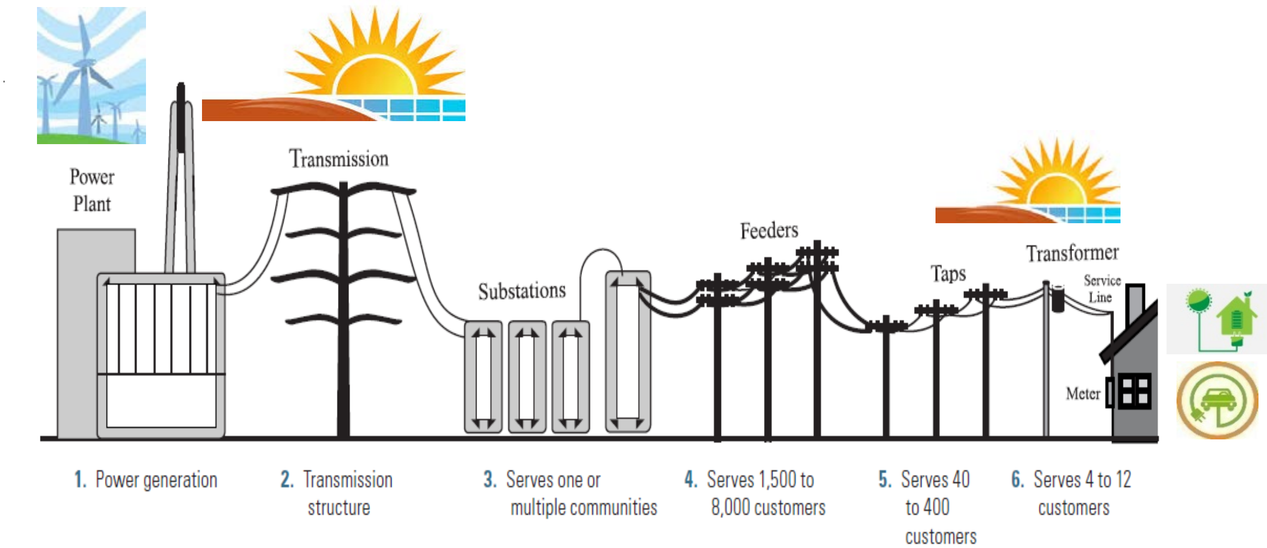


Approximately 89 percent of our NSPM system customers are residential, with commercial and industrial customers comprising most of the remaining 11 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential customers comprise approximately 31 percent of electricity sales, with commercial and industrial customers making up most of the remaining 69 percent.

III. DISTRIBUTION SYSTEM OVERVIEW

The electrical grid is composed of generating resources, high voltage transmission lines, and the distribution system, which is the vital final link that facilitates the safe and reliable flow of electricity to serve our customers as shown below.

Figure 2: Illustrative Electrical Grid



As illustrated above, the poles, lines, and cables that comprise the distribution system connect individual residents and businesses to the larger electrical grid. As a result, the distribution portion of the grid, and the services that the Company's Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota)[1] – and is composed of 1,189 Feeders, 274 distribution-level substations, approximately 15,000 circuit miles of overhead conductor on over 600,000 overhead poles, and over 11,000 circuit miles of underground cable. This system is managed and operated by the over 1,000 employees within the Company's Distribution organization, whose key functions historically have included 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. Through this work, the Company has maintained good reliability, meeting IEEE's 2020 reliability thresholds for SAIFI, SAIDI, and CAIDI at the second quartile for large utilities.[2]

IV. PLANNING LANDSCAPE

The planning landscape for the distribution system has not substantially changed since we submitted our most recent IDP in 2019. Although the foundation of our distribution system is safe, reliable energy, increasing customer expectations and

[1] In this context, the number of customers is based on the number of electric meters.
[2] See the Company's August 20, 2021 filing in our Service Quality Docket No.E002/M-21-237

technological advances have reshaped what customers expect from their energy service provider and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, continue to evolve at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utilities to manage the electric distribution grid and service to customers. The Company will soon be installing new electric meters that are equipped to gather more detailed information about customer energy usage, which we and other utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators also have access to improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

IDPs continue to be an emerging industry practice intended to give regulators and other stakeholders a more transparent view into the planning process of the distribution grid through a standardized process. Specifically, the focus of Minnesota's IDP is intended to facilitate comprehensive, coordinated, transparent, integrated distribution plans that:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies,
- Enable greater customer engagement, empowerment, and options for energy services,
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies,
- Ensure optimized utilization of electricity grid assets to minimize total system costs, and
- Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

While integrated distribution planning remains relatively new for both Xcel Energy and the State of Minnesota, we are taking steps to move the process forward and align and integrate our distribution, transmission, and resource planning processes. We are starting to implement the next generation of distribution planning tools that will increase our forecasting and analysis capabilities, and we are increasingly examining our existing tools and systems in new ways so that we can leverage them across processes that historically have been separate. We are excited about the future and continuing to provide customers with excellent service that results from a resilient system and robust, integrated planning.

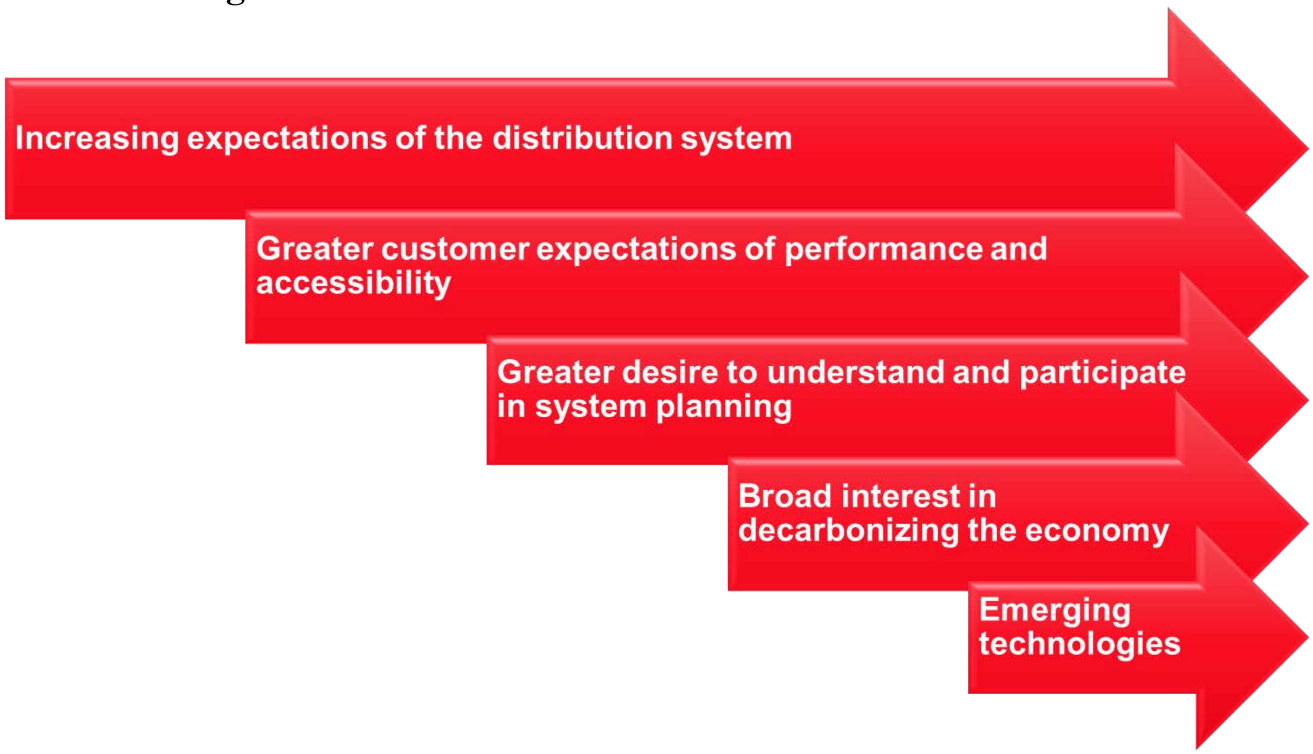
V. DISTRIBUTION STRATEGY AND PLAN

Within this planning landscape, the Company has developed strategic plans that incorporate not only the necessary work to maintain poles and wires, but also the work needed to facilitate the clean energy transition and modernize our customers' interactions with the distribution grid. Below we discuss the key drivers of our strategic plan, the elements of the strategic plan, and how that plan aligns with Xcel Energy's overall customer experience strategy.

A. Drivers of the Distribution Strategy Evolution

In developing strategic plans, the Company has identified several key drivers of the evolution of distribution plans, as reflected in Figure 3 below.

Figure 3: Drivers – Distribution Business Evolution



Increasing expectations of the distribution system. Virtually every aspect of our economy depends on access to power every minute of every day. Widespread power outages due to extreme weather, natural disasters and physical and cybersecurity threats are increasing. Grid planning must evolve to respond to the increasing volume and diversity of threats to the continued provision of reliable and resilient power. At the same time, the intermittent nature of wind and solar resources creates variability in power supply, which poses challenges to grid safety and stability, asset conditions, reliability and resilience efforts. Increasing penetrations of distributed energy resources alter traditional planning paradigms and create two-way power flows that create operational challenges to both distribution and transmission.

Greater customer expectations of performance and accessibility. The advent of advanced metering infrastructure (AMI) and the Advanced Distribution Management System (ADMS) create new and large volumes of data that can be leveraged for operations and planning, leading to improvements in the service we provide to customers. At the same time, Apps and other technologies have fueled customers' desire to be more involved with where their energy comes from and how they can play a role in managing their usage and their bills.

Greater desire to understand and participate in distribution planning. Recognizing the increasing importance of distribution planning, regulators and stakeholders have shown a marked desire for more information, more advanced planning, more input, and more insight into our future plans and investments in the distribution grid.

Broad societal and customer interest in decarbonizing the economy. Increased evidence of the impact of climate change has led to calls for reduced emissions across all sectors, which started with the electric sector and is now focused on the transportation and commercial and industrial sectors – both of which are heavily reliant on the electric grid's ability to facilitate growing electrification of goods currently powered by fossil fuels.

Expansive digitization of grid devices and capabilities. The proliferation of new technologies such as monitors, sensors, smart devices and communication networks must be assessed, prioritized, and integrated with current system assets and information systems to be fully utilized.

B. Distribution System Strategic Objectives and Plan

Recognizing the importance of the drivers discussed above, we are planning for the future. The health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future.

Our near-term investments in our distribution system, therefore, are focused on achieving three primary objectives: (1) addressing our aging assets; (2) enabling the clean energy transition; and (3) modernizing the grid. We discuss each of these strategic objectives and our plans to achieve them below.

1. Addressing Aging Assets

Our customers want quality, uninterrupted power – and their expectations in that regard continue to evolve and increase. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. Based on this analysis, we develop programs and work plans to both support our customers' needs for reliable service today and also to lay the groundwork for the grid of tomorrow.

For over 100 years, our Distribution business area has been focused on the delivery of safe and reliable electric service to our customers. Over many decades, we built our distribution network and expanded and upgraded it to meet growing customer loads. However, as load growth flattened in the early 2000s, fewer pieces of equipment were replaced through capacity driven projects. While we have been making ongoing investments to maintain the reliability of the system by replacing assets on an as-needed basis, we have now reached the point where we need to increase the level of these investments to address a greater number assets that are at or are approaching their estimated service life. Without these needed asset replacements, the system will be at greater risk of outage events due to equipment failures. Xcel Energy is not unique in its need to address its aging distribution infrastructure. An analysis from the U.S. Energy Information Administration reported that spending on electric distribution systems by major U.S. electric utilities has risen 54 percent over the past two decades, from $31 billion to $51 billion annually.[3]

To address the age and condition of our assets, we will be placing greater focus on our asset health and reliability budget to ensure that we continue to meet our long-standing priority of providing safe and reliable service to our customers. The majority of the investments in the near-term will be in established programs such as our pole replacement and substation renewal programs. We will also be adding a number of new programs to address specific assets that are, in some cases, having a pronounced impact on reliability. These new programs include a pole top reinforcement program, a porcelain cutout replacement program, an arrestor replacement program, and an end-of-life recloser program. We discuss these programs in Appendix A2: Asset Health, and Reliability Management.

We also must make significant investments to support system capacity needs due to increased loads from existing or new customers. Finally, we focus on service to our customers. For example, with certain investments in our distribution system such as in System Control and Data Acquisition (SCADA) capabilities and AMI, we enhance our capabilities to better monitor and respond to system conditions such as outages – and we can provide customers more choices related to their energy use. Additional examples are our industry-leading storm response, and our efforts to improve the estimated restoration times (ERT) we provide to customers.

2. *Enabling the Clean Energy Transition*

As discussed above, the distribution planning landscape is evolving, and we cannot and do not plan our distribution system by focusing on simply maintaining poles and wires. As supply resources are becoming less carbon-intensive and more diverse; decentralization of generation is accelerating – driven by advances in technology and new business models. While this evolution has primarily been occurring at a transmission system level, distribution systems have also begun to advance.

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

We are, therefore, targeting investments at enabling the clean energy transition by supporting the interconnection of generating Distributed Energy Resources (DER) like rooftop solar to the system and preparing the grid for greater electrification. In the near term, this electrification will occur in the transportation sector as electric vehicle (EV) use becomes more widespread. Both generating DER and greater electrification of the system will require that our distribution equipment be robust enough to maintain proper voltage levels when these new generation resources or load comes online. Our investments in our Asset Health and Reliability category will be essential to enabling our grid to handle these changes. For instance, replacing key assets like substation transformers and breakers better ensures that this equipment is able to handle these different power flows. We are also supporting DER through other investments like our Community Solar Garden Recloser program in 2022. This program will install electronic reclosers on both new and existing community solar gardens to reduce the frequency and impact of planned outages on the generation output of these resources.

We will also be supporting the clean energy transition through investments in a number of existing EV programs as well as expanding our EV offerings. Xcel Energy has committed to working with public, private, and non-profit partners to power 1.5 million EVs across the areas served by Xcel Energy's operating companies by 2030, which is 20 percent of all vehicles and is equivalent to a 30-fold increase in electric vehicles. This increase in EVs will not only save customers fuel costs but it will also significantly reduce carbon emissions. This includes work on several pilot programs that were previously approved by the Commission, the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot,[4] as well as four new pilots and programs that are currently before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending with the Commission. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket.

3. Modernizing the Grid

Another primary area of focus for Distribution is on implementing a variety of grid modernization investments. These investments will make the grid smarter and more responsive, increase system visibility and control, and enable expanded customer options. Since our last IDP, we procured LoadSEER, the next generation of

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

distribution planning tools, to increase our forecasting and analysis capabilities and help integrate our planning processes. We are also implementing other foundational components including an Advanced Distribution System Management (ADMS).

We also will be implementing several major investments to further modernize the grid in the near-term. For instance, in 2022, we will start our mass deployment of Advanced Metering Infrastructure (AMI) meters across our service territory. The AMI meters will provide value to our customers through the increased visibility and information that will allow for greater energy usage insights, reliability improvements, and enhanced rate and demand side management offerings. AMI will also provide benefits for the Company by enhancing utility planning and improved operational capabilities. We are also deploying Fault Location, Isolation, and Service Restoration (FLISR) to reduce the duration of customer outages. FLISR works by detecting faults on overhead feeders, isolating the fault, and restoring power to the unfaulted portions of the feeder. We discuss our grid modernization plans in Appendix B1: Grid Modernization and Appendix B2: Customer Strategy and Roadmap, and Appendix B3:Customer and Operational Data Management. We also discuss FLISR in the MYRP rate case we submitted October 25, 2021

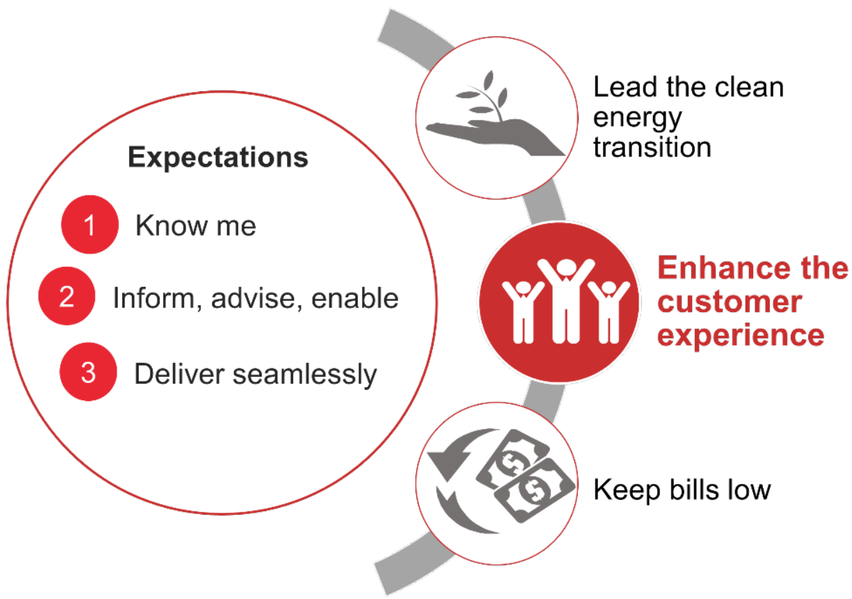
We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years. However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

C. Alignment of Advanced Grid Plans and Customer Strategy

In combination with our distribution strategy, we have developed a customer strategy that aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect. It is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their specific needs. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Rather than simply evolving from our current state, we are revisiting our entire customer experience. Today, customers expect that we *know them* and take a personalized approach to their relationship with us; they expect that we keep them *informed* and use our expertise to *advise* them about what to do and then *empower* them to take those actions; and finally that we *deliver seamless* experiences for them reducing the burden on them to take action.

Figure 4: Customer Experience Priorities



In order to meet these expectations, we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and motivations regarding the benefits and value of an advanced grid investment. We conduct robust customer research and continually update that research to ensure we are reactive to our customers' perceptions. It also requires our organization to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

The initial investments to begin meeting our customers' growing expectations with respect to the distribution system are already underway. Our implementation of the ADMS in 2021 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with AMI and our ability to leverage the underlying and necessary FAN to improve customers' reliability experience through FLISR and more. Customers will have access to granular energy usage data from our

AMI meters through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. As discussed below in greater detail, the DI platform included with the AMI meters will be able to provide customers with even deeper insights and greater benefits, particularly as we begin the process of updating the meters with new software applications, much like customers can currently update their mobile devices with applications. We are seeking certification of DI in this IDP and discuss it in detail in *Appendix G: Distributed Intelligence Certification Request.*

Transformed customer experience. In addition to providing our customers with direct benefits and insights into their energy usage, our planned grid modernization investments will combine to provide the Company with greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

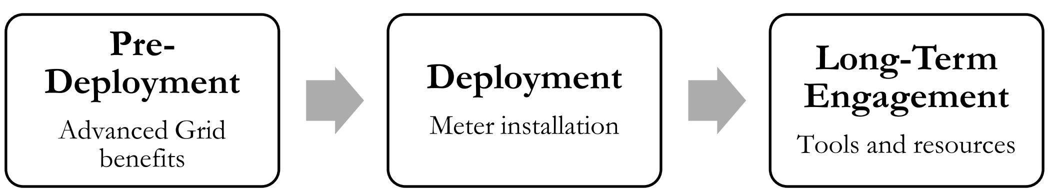
Improved core operations and capabilities. Smarter networks, supported by our investments in AMI meters and DI capabilities, will form the backbone of our operations, and will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time. Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying the location of the outage and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The investments we make now will also support future developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

D. Customers are at the Forefront of our Grid Transition

During our transition to the modern grid, we will take care to educate and inform our customers, and ensure a smooth implementation of new technologies. We have developed processes that will ensure accurate, timely bills as customers change over to AMI. We have also developed dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, and communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 5: Customer Communications Journey Phases



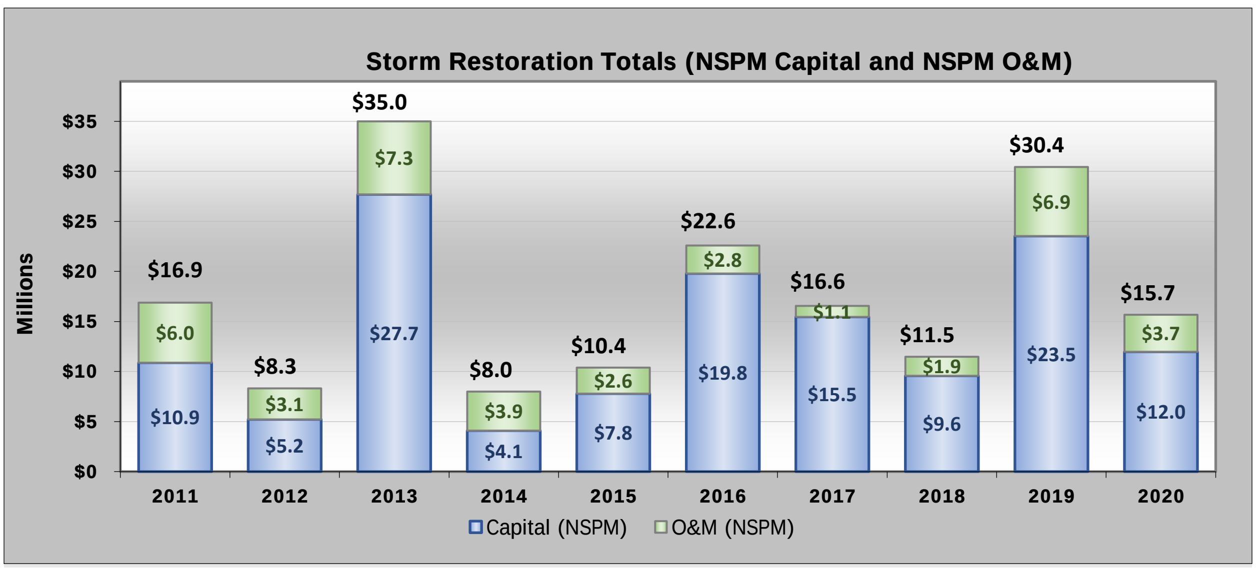
For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

VI. DISTRIBUTION FINANCIAL HIGHLIGHTS

Electric and gas utilities are long-term, capital intensive businesses. Every year, we prepare a five-year financial forecast that is used to anticipate the financial needs of each of the Xcel Energy operating utility companies, including NSPM. Historically, the overwhelming majority of the Distribution budgets have been dedicated to immediate customer reliability needs and other shorter-term investments impacted by the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

Distribution budgets must also maintain flexibility to adjust to emergent circumstances. Projects that were previously approved may be delayed to accommodate an emergency, such as storm restoration. The Figure below shows our capital and O&M storm restoration spend for the past 10 years and depicts how this spend is uneven year-to-year due to the unpredictable nature of storms.

Figure 6: Storm Restoration Capital and O&M



A. Capital Budget Forecast

The Distribution business area employs a "bottom-up" approach to budgeting and planning for the future needs of the distribution system. In coordination with the corporate budget process, the Distribution business area budgets for their work by identifying the necessary investments needed over the next five years. In addition, the Distribution capital budget is dependent on the state of the economy, which has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. We also must ensure that the existing system remains reliable.

This includes proactively replacing assets near the end of their lives as well as budgeting for replacement of facilities due to unanticipated failure or damage such as those facilities damaged during storms. To budget for proactive replacements, we evaluate the age and condition of facilities and determine the amount of replacements or refurbishments that are needed in a particular year.

As we discuss in more detail in this IDP, the health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future. To that end, our near-term investments in our distribution system are focused on achieving the three primary strategic objectives discussed above: (1) addressing our aging assets; (2) enabling the clean energy transition; and (3) modernizing the grid.

Table 1 below provides an overview of our 5-year capital budget in the IDP categories, reflecting these priorities.

Table 1: Distribution Capital Expenditures Budget – State of Minnesota – Electric 2021-2026 (Millions)

	Bridge Year	Budget					Budget Ave
IDP Category	2021	2022	2023	2024	2025	2026	2022-2026
Age-Related Replacements and Asset Renewal	$111.3	$144.3	$167.3	$173.3	$185.5	$189.6	$172.0
New Customer Projects and New Revenue	$38.7	$37.8	$38.8	$39.7	$40.7	$41.7	$39.7
System Expansion or Upgrades for Capacity	$32.6	$38.9	$40.8	$50.9	$55.5	$55.0	$48.2
Projects related to Local (or other) Government-Requirements	$28.3	$32.4	$32.2	$36.6	$39.1	$41.5	$36.4
System Expansion or Upgrades for Reliability and Power Quality	$34.4	$46.7	$37.8	$38.9	$40.1	$41.3	$41.0
Other	$48.3	$49.2	$52.8	$51.5	$41.5	$43.3	$47.7
Metering	$6.5	$4.7	$4.1	$2.8	$1.9	$1.9	$3.1
Grid Modernization and Pilot Projects	$22.6	$186.9	$201.4	$175.7	$80.7	$96.0	$148.1
Non-Investment	($2.9)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.8)
TOTAL	**$319.8**	**$539.3**	**$573.3**	**$567.7**	**$483.1**	**$508.5**	**$534.4**

Notes: Grid Modernization and Pilot Projects includes AGIS and Electric Vehicle Program; Other includes Fleet, Tools, Communication Equipment, Locating, Transformer Purchases and the Advanced Planning Tool; and Non-investment includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers, annual totals will vary based on payment and project timing.

Table 2 below shows a summary of our grid modernization capital budget, which we note includes both Distribution and Business Systems amounts.

Table 2: Grid Modernization Capital Expenditures Budget Minnesota Electric Distribution and Business Systems (Millions)

	MYRP Case Period			5-Year Period	10-Year Period
Project Component	**2022**	**2023**	**2024**	**2025-2026**	**2027-2031[5]**
ADMS	$2.2	$2.6	$2.5	$4.1	-
AMI	$84.0	$120.7	$100.6	-	-
FAN	$7.9	$13.2	$7.5	$50.3	-
FLISR	$3.9	$8.9	$8.9	$25.4	$13.1
DI[6]	$12.2	-	-	-	-
Total	**$110.2**	**$145.4**	**$119.5**	**$79.8**	**$13.1**

In terms of grid modernization, ADMS represents approximately $11 million in the 2022-2026 timeframe. Our full AMI deployment is planned to begin in 2022 and continue through 2024, with projected capital costs for AMI, FAN, FLISR and DI of approximately $368 million through 2024, and approximately $89 million through the 2031 IDP period, for a total of approximately $457 million.

B. O&M Budget and Forecast

The Distribution O&M budget includes labor costs associated with maintaining and inspecting distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management, which includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages, and damage prevention, which includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. Finally, it includes miscellaneous materials and minor tools necessary to 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.

[5] Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2022-2026.
[6] 2021 IDP certification request. Although we expect to make additional investments in DI capabilities, we are not reflecting that in this table because we have not yet developed the budgets for those investments.

Table 3 below provides an overview of our 5-year O&M budget for the Distribution business unit.

Table 3: Distribution O&M Expenditures Budget – NSPM Electric 2021 – 2026 (Millions)

Expenditure Category	Bridge 2021	Budget 2022	Budget 2023	Budget 2024	Budget 2025	Budget 2026	Budget Avg 2022-2026
Labor	$43.9	$46.5	$49.0	$50.5	$53.9	$54.9	$51.0
Cont. Outside Vendor/Contract Labor	$10.5	$10.9	$11.5	$11.5	$12.4	$12.3	$11.7
Vegetation Management	$41.2	$43.4	$46.0	$46.2	$40.8	$40.7	$43.4
Damage Prevention Locates	$13.1	$14.9	$14.4	$14.6	$14.8	$15.0	$14.8
AGIS	$5.2	$6.0	$4.7	$4.0	$3.6	$3.6	$4.4
Other (Materials, Transp, First Set Credits)	$7.1	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0
TOTAL	**$121.0**	**$127.7**	**$131.6**	**$132.9**	**$131.6**	**$132.6**	**$131.3**

Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the Distribution 5-year budget include the incremental programs of AGIS and Asset Health/Reliability plus increased Vegetation Management costs to make up for some of the line clearing that was originally planned but not completed in 2020 due to COVID.

Consistent with how we present the capital budget for our grid modernization investments, we separately present the O&M to provide a complete view of both Distribution and Business Systems amounts. See Table 4 below.

Table 4: Grid Modernization O&M Expenditures Budget Minnesota Electric Distribution and Business Systems (Millions)

	MYRP Case Period			5-Year Period	10-Year Period
Project Component	**2022**	**2023**	**2024**	**2025-2026**	**2027-2031[7]**
ADMS	$2.1	$2.0	$1.9	$4.1	$11.4
AMI[8]	$8.4	$10.2	$13.5	$26.2	$60.3
FAN	$0.4	$0.1	$0.1	$0.3	$0.7
FLISR	$0.3	$0.3	$0.3	$0.6	$1.6
Other[9]	$2.8	$9.1	$8.9	$10.0	$9.3
DI	$4.4	$7.2	$7.2	$14.4	$36.0
Total	**$18.4**	**$28.9**	**$31.9**	**$55.6**	**$119.3**

In terms of grid modernization, ADMS represents approximately $22 million of O&M through the 2031 period of this IDP. AMI, FAN, FLISR, DI and other comprise approximately $73 million of O&M through 2024, and approximately $159 million through the 2031 IDP period, for a total of approximately $232 million.

Finally, we clarify that in the IDP context, while our budget process has generally proven to be a reasonably accurate gauge of overall budget levels, it is important to understand that plan details – exclusive of large and strategic investments approved for implementation by the Commission – generally are inconsistent year-to-year. As we have explained, the Distribution budget is an ongoing and iterative process that is largely driven by the immediacy of reliability and other emergent circumstances that are the practical reality of the Distribution business. The distribution system is the connection to our customers, and we must respond to these circumstances to meet our obligation to serve and ensure we provide adequate service. This means that long-term plans, which, in a distribution context, include five-year action plans, have a much shorter shelf-life.

VII. DER SNAPSHOT AND FORECASTS

For purposes of the IDP in Minnesota, DER is defined as supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers, whether it is installed on the customer or utility

7 Period may include additional assumptions, including inflation and labor cost increases that are not part of the O&M budget in periods 2022-2026.

8 Includes shared asset costs.

9 Other includes: LoadSEER, project management costs, and contingency.

side of the electric meter. The definition further clarifies that for the IDP, DER may include, but is not limited to distributed generation, energy storage, electric vehicle, demand side management, and energy efficiency resources.

Xcel Energy has one of the longest-running and most successful Demand Side Management (DSM) programs in the country. Our annual DSM achievements have often outpaced Minnesota's 1.5 percent of sales goal. Between 1990 and 2020, we spent $1.78 billion (nominal) on demand side management efforts in Minnesota, which resulted in saving nearly 11,000 GWh of energy and avoiding approximately 3,900 MW in capacity investments. Our actions to consistently adapt and grow our customer offerings have proven worthwhile as we continue to meet and exceed the state's statutory energy savings targets. We have set forth goals in our 2020-2034 Upper Midwest Integrated Resource Plan (IRP) to significantly increase our energy efficiency efforts.[10] These efforts will be incremental to the 1.5 percent of retail sales energy savings with proposed cumulative goals of 11,795 GWh of energy savings and 2,156 MW of demand reduction over the 2020 – 2034 planning period, including the growth of our demand response (DR) portfolio to over 1,500 MW by 2034.

We have the largest community solar gardens program in the country, with 811 MW from 407 projects online, which we anticipate growing to nearly 890 MW by the end of 2021. Non-CSG distributed solar has grown from approximately 86 MW reported in our 2019 IDP to 142 MW.[11] Distributed wind has remained constant at 16 MW, and distributed storage projects interconnected to our system continue to be associated with other generation projects, with four projects complete and 18 in queue, with a total of <1 MW/DC. Tables 5 and 6 below summarize current levels of distribution-interconnected DER and how much is in the queue.

Finally, as we have noted above, we are building on our clean energy leadership by investing in infrastructure to increase access to electric vehicles (EV) and help drivers and fleet operators start driving electric.

[10] *Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan,* Docket No. E-002/RP-19-368, filed with the Public Utilities Commission, July 1, 2019 and modified thereafter.
[11] As of July 2021.

Table 5: Distribution-Connected Distributed Energy Resources – State of Minnesota

(As of July 2021)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	142	7,762	42	1,325
RDF Projects	35	25	1	1
Wind	16	66	<1	5
Storage/Batteries[12]	<1	4	<1	18

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	811	407	555	565
Grid Scale (Aurora)	100	16	70	1

Table 6: Minnesota Distributed Energy Resources – Demand Side Management and Electric Vehicles

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency*	2,022	N/A	N/A	N/A
Demand Response	738	457,787	N/A	N/A
Electric Vehicles	N/A	7,081-8,500[13]	N/A	N/A

** Note: energy efficiency is cumulative since 2005*

We discuss in this IDP how we are considering DER in our system planning and preparing for increasing levels of integration.

VIII. ADVANCED GRID CERTIFICATION REQUESTS

Consistent with our strategic plans concerning grid modernization, we are seeking certification of two advanced grid initiatives under Minn. Stat. § 216B.2425 – both of which we expect will bring significant value to our customers. We discuss these in detail in Appendix G: Distributed Intelligence and Appendix H: Resilient Minneapolis Project and summarize both below.

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[12] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.

[13] We do not have information that ties our customer accounts to electric vehicle users. *See* IDP Requirement 3.A.21 below for the sources of this range.

A. Distributed Intelligence – Customer-Facing Use Cases

The meters being installed for our AMI initiative are equipped with DI technology. Essentially, each meter contains the equivalent of a small computer that can process data in real time at the meter – harnessing powerful capabilities that we will be able to leverage to help customers better understand and reduce energy usage, and help the Company detect and respond to issues on the distribution system in a way that AMI metering alone cannot. On-meter processing is necessary to unlock these advances because practical limitations on bandwidth otherwise make processing of second and sub-second data infeasible.

We are now in the process of developing the physical and information technology infrastructure to leverage the meter's capabilities in concert with the Company's overall strategic priorities to lead the clean energy transition, enhance the customer experience, and keep customer bills low. As part of our deployment of DI, we plan to begin with specific uses of the DI capabilities that will improve our understanding of the distribution grid and enhance customers' access to information regarding their energy consumption. We anticipate that developing these DI use cases will provide the Company with knowledge and experience that will allow us to further realize the capabilities of this emerging technology. Ultimately, we expect DI to help the Company and our customers unlock even more benefits of grid-modernization.

As the Company marches toward our vision of an 80 percent reduction in carbon emissions by 2030 and 100 percent carbon-free electricity by 2050, DI is among the tools that can enable our progress. The analytics made possible through DI have the potential to make customers more than just consumers of energy – giving them the capabilities and information to be active participants in their energy usage. With detailed information about their energy usage, customers can change their behavior in ways that promote energy efficiency, saving on energy bills while also providing benefits to all customer through grid benefits and carbon reductions. Similarly, DI analytics extend the advanced capabilities of the distribution system to enable more precise monitoring and control at the edge of the grid, enabling greater reliability and lower costs to customers for managing the system.

We have three categories of customer-facing DI use cases planned for near-future deployment and then plan on implementing more complex uses of DI once we have the benefit of the lessons learned and the analytics derived from those initial uses. The three initial use cases, for which the Company is seeking certification, are: HAN connectivity, energy analysis, and electric vehicle detection.

1. HAN Connectivity

This offering involves connecting customers to the meter located on their premises using Wi-Fi. The initial application will allow customers to obtain kW and kWh reads from the meter using a mobile application offered by the Company and a corresponding DI application running on the meter which communicates with the mobile application using industry standard communication protocols. We expect this offering will initially appeal to our most energy conscious and technological savvy customers. The basic functionality provided by this use case, however, is an important building block for future use cases that we expect will appeal to a wider array of customers. The deployment will give us the ability to test internal systems to deploy DI applications and orchestrate the DI ecosystem, including software on the meter, as well as the back-end systems.

2. Energy Analysis

This use case will disaggregate appliance load profiles and allow customers to see which appliances use the most energy and how that impacts their monthly utility bills. Sometimes referred to as "nonintrusive load monitoring," appliance disaggregation utilizing DI will involve the analysis of an overall usage signal in order to determine which appliances are in use and estimate the load attributable to each. Through focus groups, we have learned that customers often have a misunderstanding of what appliances use the most energy in their homes and often equate energy saving efforts to "turning the lights off," which in reality does not have a particularly significant impact when compared to other possible actions. As a result, customers who want to reduce their energy usage for financial and/or environmental reasons often do not have the information to empower them to make knowledgeable decisions regarding the use of equipment in the home. Crucially, this analysis does not require that customers have smart appliances. Instead, a load disaggregation application running on the meter will perform on-meter analysis of the data gathered by the meter, which, when combined with further back-end processing, can provide reliable and detailed disaggregation information to customers.

3. Electric Vehicle Detection

When a customer first plugs in an electric vehicle (EV) at their premises, an extension of the same technology that enables the Energy Analysis use case discussed above can also be used to detect the presence of that EV. That can enable several important benefits for both the customer and the Company. From the Company's standpoint, it provides critical information regarding growing EV penetration on the system, allowing us to better manage and plan distribution operations for significant increased load and the resulting changing load dynamics. From the customer's standpoint, EV Detection can provide a channel to introduce customers to programs and rates that best suit their budgets and needs. The use of these programs and rates can lower the costs of EV ownership, and thus promote transportation electrification, which has important carbon emission reduction benefits. It also can benefit all other customers through the addition of beneficial load at off-peak times, which will put downward pressure on rates. Over time, EV detection could also function in the context of an Appliance Disaggregation application, as shown in the conceptual sample screenshot below.

B. Distributed Intelligence – Grid-Facing Use Cases

Grid-facing applications will provide insights to Xcel Energy to better plan and more effectively operate the system. These applications leverage the meter's ability to function as an edge-of-grid sensor, monitoring the system's performance all the way to the customer's service at the very edge of the secondary voltage portion of the system. As with other DI use cases, the meter is used for localized analysis of data collected by the metrology board, and the results of those analyses can then be shared with the Company's back-end systems and/or other meters in the vicinity.

There are three fundamental types of grid-facing applications:

- Applications that gather data for analysis (e.g., Connectivity),
- Applications that provide notification by exception (e.g., Secondary Equipment Assurance, Meter Bypass Detection), and,
- Applications that provide for local control.

The Company's initial planned deployments, for which it is seeking certification, fit into the first two categories. Xcel Energy's approach to grid-facing DI is to begin with applications that have already been developed and are available for purchase, and then continue to develop and deploy progressively more complex applications which will provide progressively more valuable insights.

1. Secondary Equipment Assurance

Secondary conductors carry power between the company's distribution transformer and the customers' meters. Our system in Minnesota has nearly 980,000 such secondary conductors. When problems arise with the secondary conductors, the result can be outages, partial outages, and voltage fluctuations which disrupt our customers' homes and businesses and can lead, in some instances, to customer equipment malfunction. Historically, it was not feasible for us or our peer electric utilities to monitor this portion of the grid. There are simply too many individual conductors and it would be cost prohibitive to install monitoring devices on all of them or even a substantial subset. Instead, when a problem develops, we often first learn of the issue because a customer notices (for example lights within a home may be flickering) and then calls and requests assistance. In that example of the flickering lights, we would respond by sending a worker to investigate and install a temporary recording voltmeter, if necessary.

AMI meters with DI capability offer the first practical solution to this issue. To monitor the secondary portion of the system, we will leverage two existing DI applications available from the meter vendor: (1) the High/Low Impedance Detection application, and (2) the Open Secondary Neutral application.

High/Low Impedance Detection. This application monitors the health of connections and can detect certain deterioration of the energized conductors. Deteriorating or loose connections, as well as deteriorating conductors, tend to progress to failure over time at which point the customer will experience a partial or complete outage. But prior to that point, customers can experience voltage fluctuations causing customer complaints due to light flicker or equipment malfunction. However, even if there are flickering lights or other signs of a developing problem, customers may not notice or may contact Xcel Energy. This application running on the meter can take current and voltage meter data collected by the meter and analyze it to calculate the impedance and send an alert to our system if the impedance falls outside of a normal range or increases consistently, which are signs that a problem is developing.

Open Secondary Neutral. Occasionally, customers may experience an unbalanced voltage problem if a neutral connector opens. When this happens, some lights within a home appear dim, while others are brighter than normal. However, because the home or business continues to have electricity and the damage develops slowly, the problem is often not immediately obvious to the customer. In addition, issues with neutral connectors are difficult to detect and involve intensive manual labor and/or voltage tests. The Open Secondary Neutral application will monitor the system and notify the Company if an open neutral is detected which will allow us to avoid the time and expense associated with manual inspections and proactively resolve problems, thereby reducing customer complaints and damage to their equipment.

2. *Meter Bypass Theft Detection*

Diversion – or theft – by meter bypass occurs when a person intentionally alters a meter installation or otherwise bypasses the electrical meter, such that some or all of the power consumed does not pass through the meter and is therefore unbilled.

Diversion implicates both safety and financial ramifications. Such action is illegal and is done while equipment is energized, typically by unqualified persons. The bypass work thus puts the person performing it at risk and the result is often a public safety and fire hazard. Today, the Company typically becomes aware of diversion primarily through identification during site visits, as a result of data analytics, or if someone informs the Company or authorities regarding the bypass. There is an application currently available to detect meter bypass diversions. Given that the Company does not have reason to believe that meter bypass diversions are common, the most important benefit of this use case would be to eliminate the public safety hazards.

3. Connectivity

Knowing the precise location of the customer's premises and how it is connected to the grid is foundational to the Company's ability to plan and operate our system and to keep our customers informed. The mapping of customers to the system is maintained in our Geospatial Information System (GIS), which forms the basis for all of our system planning and modelling. When locations are not correctly mapped, that results in less accurate ADMS solutions, planning models, and hosting capacity calculations. Highly accurate detailed distribution system data is critical to building system models and performing the complex engineering studies necessary to more efficiently integrate DER generation with the distribution grid. The core DI application will leverage the meters' Power Line Carrier (PLC) communication devices to enable the meters to self-identify themselves to each other and form groups that we can compare with distribution transformer groupings, which are mapped in GIS. These comparisons will identify outliers that need correction.

The benefits of grid-facing connectivity use cases are improved accuracy in outage management and notification, and improved accuracy in planning and operational modeling, including ADMS and hosting capacity analysis.[14] This application will correct the connectivity to mis-mapped customers, reducing this source of error. All processes that rely on the connectivity model in our GIS, including outage management, will benefit from the improved data. Going forward, this use case can also be used to maintain the accuracy of our GIS mapping after modifications to the secondary system.

[14] We previously informed the Commission that implementation of our AMI project would provide opportunities for improvements to the data available for hosting capacity analysis. *In the Matter of the Xcel Energy 2020 Hosting Capacity Report Under Minn. Stat. § 216B.2425, Subd. 8*, E002/M-20-812, Hosting Capacity Analysis Report (Nov. 2, 2020), Attachment F at 11. This DI use case provides just such an opportunity.

C. Distributed Intelligence Costs

1. Capital and O&M

The capital costs of deploying DI solutions consist of foundational architecture development, infrastructure development, and use case development. These use case development budgets are each based on expected development of three customer-facing use cases, as well as three grid-facing use cases of similar complexity for deployment in 2022. Table 7 below provides the capital costs broken down by category. As the Company currently only has specific plans through deployment of the initial use cases, the capital budget only consists of expenditures in 2021 and 2022. These budgeted expenditures will provide the foundational capabilities and initial use cases to begin using DI. As we move forward and make decisions regarding future use cases, we will budget for and make additional investments.

Table 7: Capital Costs Budget

Cost Category	Detail Cost Category	2021 Budget	2022 Budget
Software Architecture	Internal Development Costs	$ 332,500.00	$ 308,693
	3rd Party Onshore	$ 798,000	$ 2,778,237
	3rd Party Offshore	$ 199,500	$ 138,912
Infrastructure / Hardware	Customer-Facing Infrastructure Cost	$ 332,500	$ 991,777
	Grid-Facing Infrastructure Cost	$ 798,000	$ 457,743
	Itron App Package Infrastructure Cost	$ 199,500	$ 585,242
Use Case Development - Grid Facing	3rd Party Onshore Development	$ -	$ 2,159,391
	3rd party Offshore Development	$ -	$ 539,848
	Xcel Energy Development	$ -	$ 899,746
	Itron App Package Development Cost	$ -	$ 1,463,106
Use Case Development – Customer-Facing	3rd Party Onshore Development	$ -	$ 2,159,391
	3rd Party Offshore Development	$ -	$ 539,848
	Xcel Energy Development	$ -	$ 899,746
	Itron App Package Development Cost	$ -	$ 1,463,106
Total		**$ 2,660,000**	**$ 15,384,787**

O&M costs are as follows:

Table 8: O&M Budget

Cost Category	Detail Cost Category	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
Customer Support and Governance	Governance and Change Management	$ -	$9,115	$14,921	$14,921	$14,921	$14,921
	Product Development	$152,000	$109,379	$179,058	$179,058	$179,058	$179,058
	Sales & Marketing	$ -	$27,345	$44,764	$44,764	$44,764	$44,764
	Customer Service	$ -	$45,575	$74,607	$74,607	$74,607	$74,607
	Third Party Consulting	$ -	$729,194	$1,193,718	$1,193,718	$1,193,718	$1,193,718
System upgrades and maintenance	Architecture Run Cost	$ -	$674,505	$1,104,189	$1,104,189	$1,104,189	$1,104,189
	Use Case Run Cost	$ -	$2,807,399	$4,595,816	$4,595,816	$4,595,816	$4,595,816
Total		$152,000	$4,402,512	$7,207,074	$7,207,074	$7,207,074	$7,207,074

2. *Estimated Customer Bill Impacts*

Keeping customer bills low is an Xcel Energy strategic priority and is a central consideration of our grid modernization efforts. As we have discussed, the investment in DI foundational capabilities and initial use cases will provide significant value to our customers. It will, however, also have an impact on customer bills, resulting from the increased revenue requirement due to our investments and O&M spending necessary to implement this initiative.

As we did when we proposed certification of AMI and FAN in our 2019 IDP, we have performed a high-level revenue requirement analysis for 2022 through 2026 to illustrate the incremental revenue requirement and estimated bill impact of the DI foundational capabilities and initial use cases. While we did not perform a class cost of service model for this subset of investments and O&M expenses, this analysis provides an estimate of the monthly bill impact for a typical residential customer. We estimated the bill impact by utilizing a series of allocation assumptions applied to the costs, using allocators consistent with our 2022 proposed Class Cost of Service Study in the MYRP rate case we submitted on October 25, 2021 to derive an estimated overall cost per kilowatt hour (kWh). For an average monthly residential customer using 600 kWh, our assessment estimates a bill impact of approximately $0.31 per month in 2026.

3. *Cost-Benefit Ratio*

The CBA indicates that the ratio of quantifiable benefits to costs is 0.93. Although this is slightly lower than 1.0 (the level at which quantifiable benefits and costs are equal), it does not take into consideration other non-quantified benefits such as distribution grid reliability and efficiency, environmental benefits, public safety, and future use cases.

Table 9: DI Foundational Capabilities and Initial Use Cases Cost-Benefit Ratio Net Present Value 2021 (millions)

	Total
Benefits	**40**
O&M Benefits	0
Other Benefits	40
CAP Benefits	0
Costs	(43)
O&M Expense	(26)
Change in Revenue Requirements	(17)
Benefit/Cost Ratio	**0.93**

Crucially, the development of foundational DI capabilities and deployment of initial DI use cases will position the Company to subsequently deploy future DI use cases which will further benefit the Company, customers, and the environment. Although the Company cannot quantify such benefits at this time, they are expected to be considerable, and it is not unusual for an investment in foundational technology to have a benefit to cost ratio below 1.0.

We, therefore, believe developing these foundational use cases is in the public interest now, and that value will only grow over time as the Company develops future capabilities.

D. Resilient Minneapolis Project

The concept for the Resilient Minneapolis Project (RMP) initiative started in the Company's 2019 IDP with discussions with the City of Minneapolis around a Non-Wires Alternative (NWA) Pilot. We continued those discussions with the City and subsequently in the 2020 economic recovery docket, we proposed an NWA pilot in Minneapolis focusing on rooftop solar, EV charging, battery storage, demand response, and energy efficiency. The estimated budget was between $4 and $8 million, with tentative locations discussed in our original Minnesota Economic Recovery filing (Docket E,G999/CI-20-492). Through continued discussions, we determined there was not a need for a traditional NWA project in Minneapolis at this time. Instead, the focus on resilience within the Black, Indigenous, and People of Color (BIPOC) community came to the forefront. The RMP, as the Company is currently pursuing it in collaboration with our community partners, remains fundamentally consistent with the NWA pilot proposed in 2020, but the objectives are considerably broader. We are now seeking to enhance community resilience and deliver an array of grid services during routine, non-emergency operations.

The past two years have brought unprecedented economic and social hardship to the residents of Minneapolis, including economic and health impacts from the COVID-19 pandemic and the civil unrest following the murder of George Floyd. These events have disproportionately impacted BIPOC communities, and have led to increased efforts to address the racial inequities that persist in Minnesota. They have also focused attention on the fact that BIPOC communities tend to be disproportionately vulnerable to a variety of disruptions, including but not limited to the impacts of climate change, and are seeking ways to improve community resilience to such disruptions.

At the same time, the Company and other stakeholders are seeking ways to integrate into the electric system new distribution-level technologies like distributed solar, battery systems, and microgrids that can deliver a wide array of benefits to the electric system. These benefits, if systems are carefully planned and optimized, include backup power for resilience during outages, mitigation of peaks at the system and feeder level, local distribution system support, deferral of conventional distribution system investments, and emission avoidance, among others.

The Resilient Minneapolis Project (RMP) is a proposed initiative, implemented at three Minneapolis locations with BIPOC-led partner organizations that seeks to improve communities' resilience to crises while providing ancillary benefits to the distribution grid and advancing the Commission's objectives for IDPs.

The RMP will be implemented at three locations: (1) the North Minneapolis Community Resiliency Hub; (2) Sabathani Community Center; and (3) the Minneapolis American Indian Center. At each site, the Company will work with partners to install rooftop solar, battery energy storage systems (BESS), microgrid controls, and necessary distribution system modifications to integrate these technologies.

The primary benefit for the site hosts of the RMP projects is enhancing resiliency, generally needed infrequently and for brief durations. During normal grid operations, the solar and BESS assets will be managed to deliver a range of grid benefits: dispatched and optimized to mitigate peaks at the system and feeder level, integrate more solar generation, and reduce emissions. In addition, designing the RMP projects in collaboration with BIPOC-led organizations has brought into focus that these communities have broader energy equity objectives that are not limited to serving as Resilience Hubs. These include:

- Energy affordability and reducing energy burden for community residents and businesses;
- Equitable access to renewable energy, and the opportunity to use renewable energy and energy efficiency projects to create jobs and build community wealth in chronically under-resourced and under-invested communities;
- Workforce training, diversification, and BIPOC energy careers; and
- Environmental justice concerns and the desire to reduce or eliminate GHG and/or criteria pollutant emissions in neighborhoods that have historically suffered disproportionate pollution impacts.

All our RMP partners are active in workforce readiness and career pathways, in some cases specific to clean energy workforce development. We are designing the RMP projects to link directly to workforce development in solar, energy storage and related areas.

1. *Selected RMP Sites*

Following a competitive application process, with six applicants, the Company selected three community organizations to partner with.

a. Renewable Energy Partners (REP): North Minneapolis Community Resiliency Hub

REP is a state and local-certified Minority Business Enterprise (MBE) based in North Minneapolis and formed in 2014.[15] Its vision is to "address the numerous disparities in our community, including education, skills gaps, and economic participation, to increase the health, wealth, and homeownership of those around us."[16] REP's goals are to 1) develop solar energy and other energy projects with community benefits, 2) provide electrical and construction labor for Minnesota's solar energy market, and 3) training and jobs for BIPOC workers in utility and energy-related careers.

The North Minneapolis Community Resiliency Hub will be implemented on three MPS buildings: Hall Elementary School at 1601 N. Aldrich Avenue, Franklin Middle School at 1501 N. Aldrich Avenue, and the MPS Nutrition Center at 812 Plymouth Avenue N. These three buildings are just north of Plymouth avenue and a few blocks

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[15] This section is derived from REP's website, Firm Capability Statement attached to this filing, and response to Resilient Minneapolis Project call for applications, April 2021.

[16] Commercial Solar Energy | Renewable Energy Partners | Twin Cities (renewablenrgpartners.com).

east of the RATC. The project site is within the City of Minneapolis' Northside Green Zone, federal EDA Opportunity Zone and HUD Empowerment Zone.[17] It is also part of the East Plymouth Innovation Corridor. The area served by the North Minneapolis Community Resiliency Hub is primarily BIPOC and low-income. About 85 percent of Franklin students and 96 percent of Elizabeth Hall students are eligible for Free and Reduced Lunch, compared to 55 percent for MPS overall. The estimated population served by the project is 4,775 residents and 15 businesses, including critical infrastructure such as the Comcast technical center and Hennepin County Service Center.

The North Minneapolis Community Resiliency Hub aims to create an island-able resiliency hub to provide emergency services to the community. The hub will serve as a base of operations for emergency response, providing essential services such as shelter, cooling center, electricity, food, water, communications, and phone charging in an emergency. The MPS Nutrition Center has capacity to prepare thousands of meals for delivery throughout Minneapolis in the event of an extended outage.

The proposed technologies are:

- MW rooftop solar PV, spread across the three buildings
- 1.5 MW / 3 MWh lithium-ion Battery Energy Storage System (BESS)
- Adaptive microgrid controller, designed to balance DER generation with load and provide multi-site balancing in emergencies
- Electric gear to interconnect and enable islanding of the three MPS buildings from the surrounding distribution system

b. Sabathani Community Center

Sabathani Community Center was established in 1966 with a mission to provide people of all ages and cultures with essential resources that inspire them to improve their lives and build a thriving community.[18] Called by its Board the "soul of South Minneapolis," Sabathani has served as a pillar for community identity, empowerment, and social change for over 50 years. Sabathani serves over 43,000 community members in South Minneapolis each year with community-oriented, culturally sensitive services and programming.

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[17] U.S. Department of Housing and Urban Development Empowerment Zones are designated areas of high poverty and unemployment that benefit from tax incentives provided to businesses within their boundaries. See https://www.hud.gov/hudprograms/empowerment_zones.

[18] This section is derived from Sabathani Community Center's website and Sabathani's response to Resilient Minneapolis Project call for applications, April 2021.

Sabathani is located at 310 East 38th Street in South Minneapolis. Sabathani estimates the area served by a community resiliency hub would extend from Nicollet Avenue on the West to Bloomington Avenue on the east, and from 36th Street on the north to 40th Street on the South, with an approximate population of 72,000 people and over 30 businesses.

Sabathani is at the core of the 38th Street Thrive Cultural District approved by the Minneapolis City Council in early 2021, with a vision to "continue the legacy and heritage of a deeply rooted African-American community by preserving our economic vibrancy, creative identity, and affordability that strengthens the vitality, resilience and partnership of the people who live and work in the district." Notably, the 38th Street Thrive strategic plan envisions creating a Resilience Hub at Sabathani to "enhance our ability to recover from traumas, disturbances, shocks or stresses due to climate changes, power outages, medical outbreaks, fires or other human-caused disasters…" and "serve as a facility in supporting the community before, during, and after disruptions by 1) mitigating climate change using resilient energy systems, 2) providing opportunities for the community's benefit with a solar farm cooperative, 3) providing local emergency management and communication, 4) coordinating the distribution of essential resources - shelter, water, food, medical supplies etc. when needed, and 5) creating a mobility hub with bike lanes, bus transit, bike parking and wheelchair accessibility, etc." Funding through the RMP – while it cannot support every one of these objectives – would enable Sabathani to move forward on key aspects of this vision to become a Resilience Hub for the 38th Street Thrive Cultural District.

The proposed technologies are:

- 240 kW AC rooftop solar PV system, sized based on a preliminary solar assessment from Elevate;
- 1 MWh (500 kW, two hour) BESS; and
- Electric gear to interconnect and enable islanding of Sabathani from the surrounding distribution system.

c. Minneapolis American Indian Center

The Minneapolis American Indian Center (MAIC), built in 1975, is focused on serving a large and tribally diverse urban American Indian population, numbering well over 35,000 in the eleven-county Minneapolis-St. Paul metro area.[19] MAIC hosts over 10,000 visitors annually, and engages 43 different American Indian tribes along Minneapolis' American Indian Cultural Corridor. MAIC serves as a central meeting

[19] This section is derived from MAIC's website and response to Resilient Minneapolis Project call for applications, April 2021.

location for urban American Indian organizations, community-based organizations, educational institutions, and entrepreneurs from throughout South Minneapolis, surrounding neighborhoods and the greater Twin Cities.

MAIC's programs and services are predominately focused on Native American children, youth, adults, elders, and families. Most participants are low-income and experience significant opportunity gaps in health and wellness, education, access to basic needs and resources, housing, living-wage jobs and career pathways, civic and community engagement, and long-term economic stability and prosperity. MAIC's culturally supportive programming engages urban Native Americans within the context of their own traditions and experiences, promoting positive outcomes and addressing disparities between the Native and mainstream populations. MAIC also functions as a cross-cultural bridge by providing a destination for non-Native people to attend events, seminars, performances, and exhibitions. The MAIC is located at 1530 E Franklin Avenue, in the heart of Minneapolis's American Indian Cultural Corridor. The approximate population served is 22,015, with an approximate business count of 500.

The energy and resilience activities at MAIC fall within a planned renovation and expansion of their existing space, roughly doubling its size from about 30,000 sq. ft. currently to about 65,000 sq. ft. This will update the existing spaces, improve the sustainability and efficiency of the building, and create a broad array of new multi-use spaces for programs, service delivery and events. The current plan is to begin construction in late spring/early summer 2022, which aligns well with the RMP timeline.

MAIC's proposed RMP investments will support community-identified needs for the facility as a core gathering place for cultural, social, arts, and physical fitness activities for the Native community, reduce operating costs, enhance MAIC's ability to generate revenues, and improve visibility, access and security and include:

- Rooftop solar PV system of around 200 kW, installed on the approximately 35,000 sq. ft. of new roof space on the addition, with the possibility of additional capacity on existing roofs contingent on structural and shading constraints;
- 1 MWh (500 kW, 2 hour) BESS;
- Back-up natural gas/diesel generator for emergency power; and
- Electric gear to interconnect and enable islanding of MAIC from the surrounding distribution system.

MAIC is working with Xcel Energy's Energy Design Assistance program to finalize key aspects of the upgraded HVAC systems, thermal envelope, efficient lighting, food preparation, and building automation system. The renovation is being planned to meet Minnesota's B3 building standards. These costs are *not included* in this certification request. The Company is working with MAIC to identify ways to help fund those activities through CIP rebates and/or external cost sharing.

E. RMP Costs and Benefits

The following table summarizes estimated costs for the three RMP sites. Note these are preliminary estimates, to be refined with more detailed design work and vendor estimates once the Company conducts an RFP process in 2022. Costs of rooftop PV systems will be borne by the RMP hosts and/or their financial partners. Costs included in this request for certification are comprised of capital cost of the BESS, interconnection costs at each site (medium voltage work, site preparation, islanding switch, etc.), and systems integration, security and communications, plus annual O&M costs.

Table 10: Cost Estimates for each RMP Site (preliminary)

	North Minneapolis Community Resiliency Hub	Minneapolis American Indian Center	Sabathi Community Center	Total
A. Capital Costs				
Battery Energy Storage System	$ 2,123,123	$ 940,163	$ 940,163	$ 4,003,449
Islanding Switch (ATO)	$ 241,800	$ 241,800	$ 241,800	$ 725,400
Medium Voltage work	$ 128,464	$ 56,668	$ 112,964	$ 298,096
Site Evaluation/Surveying/Prep/Etc.	$ 211,420	$ 211,420	$ 211,420	$ 634,260
Business Systems Integration	$ 330,274	$ 330,274	$ 330,274	$ 990,822
Project Management and labor	$ 236,890	$ 220,075	$ 282,075	$ 739,040
Miscellaneous	$ 639,396	$ 382,835	$ 525,579	$ 1,547,811
Total capital	$ 3,911,367	$ 2,383,235	$ 2,644,276	$ 8,938,878
B. Annual O&M Costs				
Annual O&M	$ 23,861	$ 19,091	$ 19,091	$ 62,043

In terms of benefits, the solar, BESS, and microgrid controls installed at the three RMP sites will deliver multiple benefits. These include benefits to the host organizations themselves, to the communities they serve, benefits for grid modernization, and learnings to the benefit of the Company's customers overall.

Some of the benefits are quantifiable in dollar terms, which we do in the form of a cost-benefit ratio outlined below. Others are non-quantifiable but no less important – including training and job creation and energy "justice" objectives. Additionally, the Company will learn about how to optimize these services, recognizing not all can be delivered at once – benefitting all of the Company's customers, not just these three partner organizations.

Table 11: Cost and Benefit Summary Table for RMP

	Units	North Minneapolis Community Resiliency Hub	Sabathani Community Center	Minneapolis American Indian Center	Aggregate
COSTS					
Capital					
Total Capital Cost	$	$3,911,367	$2,644,276	$2,383,235	$8,938,878
O&M					
Annual O&M Cost	$	$23,861	$19,091	$19,091	
NPV of Annual O&M Costs (10 years)	$	$172,662	$138,146	$138,146	$448,953
Total Capital and O&M	**$**	**$4,084,029**	**$2,782,421**	**$2,521,381**	**$9,387,831**
BENEFITS					
Resilience/Value of Lost Load	$	$575,076	$575,076	$460,060	$1,610,212
Bulk System Capacity Value	$	$111,344	$54,384	$65,643	$231,371
Generation & Carbon Emissions		$133,138	$25,417	$22,997	$181,551
Arbitrage	$	$62,174	$3,173	$12,417	$77,764
Lifetime Benefit	$	**$881,732**	**$658,050**	**$561,117**	**$2,100,899**
BENEFIT:COST RATIO		**0.22**	**0.24**	**0.22**	**0.22**

We note that the benefit-to-cost ratios fall well below 1.0. We understand the priority placed by the Commission on advancing development of distributed energy systems that combine solar and energy storage to create multiple grid benefits. Also, the emergency back-up role these BESS projects support in these applications could support communities in times of significant or prolonged duress, which is inherently hard to value, and as such not included in these results.

In summary, these advanced grid initiatives meet the statutory criteria for certification in that they help to modernize the distribution system by enhancing reliability and improving security against physical threats, including but not limited to physical threats (i.e. extreme weather events) that are anticipated to increase in frequency and severity due to a changing climate. They also provide energy conservation opportunities and facilitate communication between the utility and its customers through the use of control technologies, energy storage and microgrids, and other innovative technologies. Beyond these statutory criteria, DI and RMP will deliver a broad range of benefits as summarized in this IDP, including an enhanced customer experience, greater DER integration, improved system safety and reliability, emissions avoidance, workforce training and diversification, enhancing energy affordability, and environmental justice.

IX. ACTION PLAN SUMMARY

The first five years of our action plan will be focused on providing customers with safe, reliable electric service and modernizing the distribution grid with foundational capabilities including AMI, FAN, ADMS, and FLISR. We will also be further integrating our new LoadSEER system planning tool toward advancing our forecasting and other planning capabilities.

We are also proposing new initiatives and changes to current efforts, as summarized below:

- Certification of Distributed Intelligence, as discussed in Appendix G. By the end of 2021, we expect to complete foundational capability development to enable the initial use cases. These capabilities create the basis for foundational capabilities to be deployed in 2022 as meters are installed for both the grid and to customers.
- Certification of the Resilient Minneapolis Project, as discussed in Appendix H. If certified we will work with our community partners to implement the as quickly as feasible, targeting projects coming online by summer 2023.
- As discussed in Appendix F: Non-Wires Alternatives Analysis, we propose changes to our NWA analysis based on changes in the industry and feedback from stakeholders. We intend to use this new approach with our 2022 analysis, subject to feedback from stakeholders and the Commission.

Although not specific to grid modernization, we point out that we discuss other near-term focus areas and priorities in Appendix D: Distribution Financial Information and Appendix A3: Standards, Asset Health, and Reliability Management, where we discuss the need to invest in our system to ensure that we are able to continue to provide reliable electric service today and in the future. We outline how we intend to address aging assets, enable the clean energy transition, and modernize the grid. We are also taking near-term actions to improve the way that we are integrating DER – and longer-term, the potential implications of increased penetration levels from current programs or the recent FERC Order 2222; we discuss these in Appendix E1: System Interconnection.

See *Appendix B1: Grid Modernization* and related appendices and attachments as referenced for discussion regarding our grid modernization and related customer, data, and cost recovery plans. We summarize our current initiatives underway in the below Table.

Table 12: Grid Modernization Implementation Timeline

Program	Implementation Timeline
ADMS	Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.
TOU Rate Pilot	Launched in November 2020 and expected to conclude in late 2022.
AMI	Meter deployment scheduled for 2022-2024
FAN	The implementation of FAN is underway. We started the initial network and security design in 2020 and installed and programmed the first FAN device in May 2021 and will continue installing FAN devices through 2024. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed.
LoadSEER	LoadSEER, was first used in Minnesota in September of 2020
FLISR	Installation for FLSIR devices (reclosers, switches, and substation relays) began in 2021 on select feeders.

Finally, we note, related to our implementation of AMI, we also intend to submit a filing regarding our phased plans to enable the remote connect and disconnect capabilities of the AMI meters in early-2022. We outlined our phased plan to stakeholders in a December 2020 workshop and our 2021 IDP stakeholder workshop in September 2021. We are planning to preview our plans in more detail with key stakeholders in Q4 2021, to gather feedback that we will use to further inform and shape the petition that we submit in early 2021.

Finally, while we have not incorporated our anticipated Distributed Energy Resource Management System (DERMS) into a specific timeline or proposal, we discuss it and our awareness of the need to develop many or most of these capabilities in Appendix B1: Grid Modernization. We are currently in the initial stages of ideation, but see a DERMS playing a key role in a future of increasing DER and FERC Order 2222 – both also discussed in this IDP.

In addition to discrete grid modernizations investments, our corporate information technology infrastructure will require attention and investment on an ongoing basis to continue to meet increasingly demanding cybersecurity, data traffic, reliability, and compliance requirements along with the service expectations of our customers. Many of the investments discussed within this report involve additional data and communication needs, and a current information technology infrastructure is critical to supporting those efforts.

CONCLUSION

This IDP presents a comprehensive view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value and that the fundamentals of our distribution business remain sound. We respectfully request the Commission accept this IDP and certify our proposed grid modernization investments.

APPENDIX A1: SYSTEM PLANNING

The Distribution system is the final link of the electric system that delivers electricity to every home and business in the Northern States Power Company-Minnesota (NSPM) operating company service area. The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. We extend service to new customers or increase the capacity of the system to accommodate new or increased load, repair facilities damaged during severe weather to quickly restore service to customers, and perform regular maintenance and repairs on poles, wires, underground cables, metering, and transformers. Distribution is also at the forefront of working to transform the distribution grid to enhance its security, efficiency and reliability, to safely integrate more distributed resources and support electrification, and to enable improved customer products and services.

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 leading the clean energy transition, keeping customer bills low, and enhancing the customer experience.

I. OVERALL APPROACH TO SYSTEM PLANNING

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We see this changing as our planning processes evolve, to analyze future electricity *connections*, rather than just loads. In this section we describe our present processes, and we discuss how we expect to advance our planning and forecasting capabilities with our new planning tool.

The purpose of these assessments is to proactively plan for the future and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0 operation) and *single contingency* (N–1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully-functional. Single contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service.

Corrective actions identified as part of the planning process may include a new feeder or substation, adding feeder tie connections, installing regulators, capacitors, or upsizing substation transformers. As our planning processes evolve and technologies mature, we will continue to consider non-wires alternatives. For each project, we develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors including operational requirements, technical feasibility and future year system need.

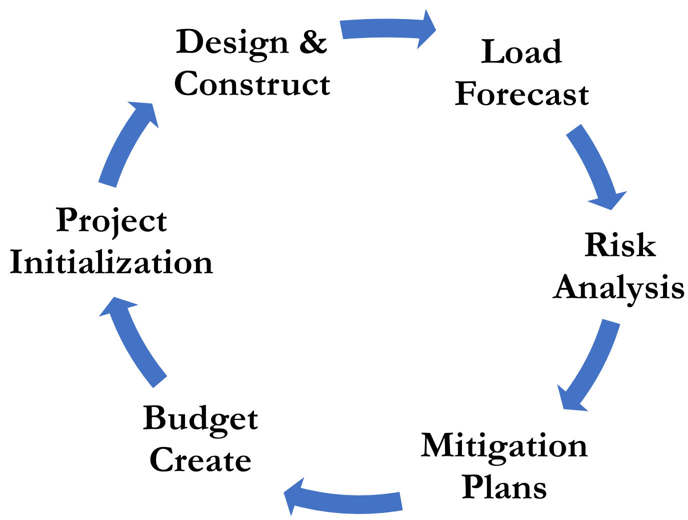
Proposed projects are funded as part of an annual budgeting process, based on a risk ranking methodology that also funds other distribution investments and expenditures including asset health, grid modernization, and emergent issues such as storm response and mandated projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public projects such as road widening or realignment.

In this Section, we describe the Company's distribution system planning approach, including planning processes and tools used to develop the annual plans. In compliance with Ordering Point Nos. 9 and 10 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, we provide the following as Attachments D and E, respectively to this IDP:

> *9. Xcel shall provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology, in future IDPs.*
>
> *10. Xcel shall provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.*

We analyze our distribution system annually and conduct additional analyses during the year in response to new information, such as new customer loads, or changes in system conditions. In the Fall of each year, we initiate the planning process – beginning with the forecast of peak customer load and concluding with the design and construction of prioritized and funded capacity projects, as summarized in the below figure.

Figure 1: Annual Distribution Planning Process



As part of our annual distribution planning process, we thoroughly review existing and historical conditions, including:

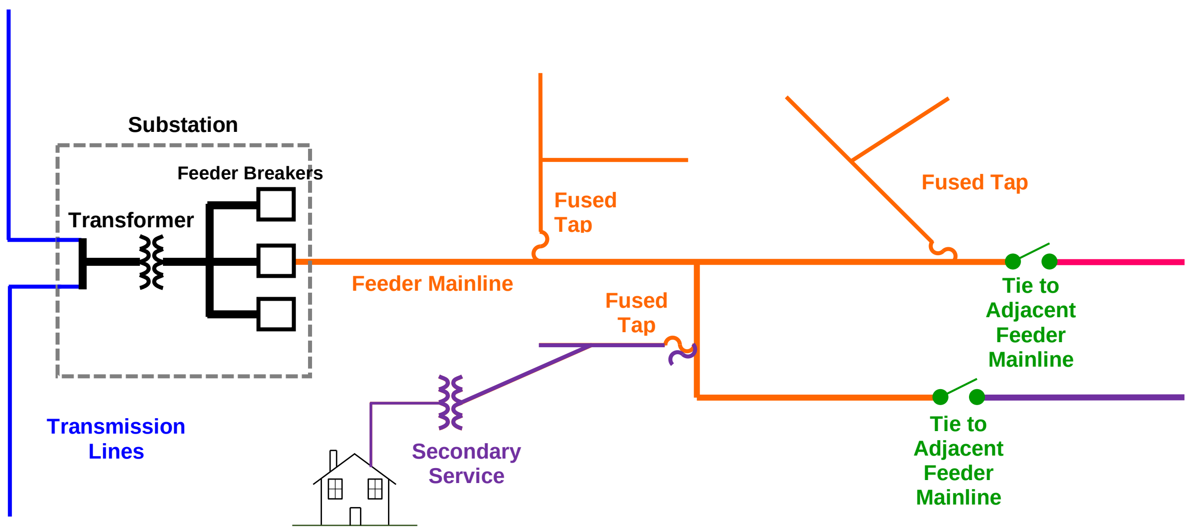
- Feeder and substation reliability performance,
- Any condition assessments of equipment,
- Current load versus previous forecasts,
- Quantity and types of DER,
- Total system load forecasts, and
- Previous planning studies.

We begin our annual plans in the fourth quarter, using measured peak load data from the current year, as well as historical peak information to forecast the loads on our distribution system over a five-year time horizon. We then perform our risk analysis based on loads near the middle of the forecast period. Tangibly the annual system planning information presented in this IDP is the result of the planning process initiated in Q4 2020. For this process, we used 2019 actuals and historical peak information along with any known system changes to forecast the 2021 to 2025 peaks, and perform our risk analysis based on the forecasted 2022 peak.

A. Feeder and Substation Design

Distribution feeders for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system, within established standards for reliability, which typically measure the average duration (System Average Interruption Duration Index or SAIDI) and frequency (System Average Interruption Frequency Index or SAIFI) of interruptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour. Foundational components in distribution system design and planning are substations and feeders.

Figure 2: Distribution System: Basic Design
Schematic of Typical Radial Circuit Design



We plan and construct distribution substations with a physical footprint sized for the ultimate substation design, which is based on anticipated load, but can occasionally be limited by factors such as geography and available land. The maximum ultimate design capacity established in our planning criteria is three transformers at the same distribution voltage. There are two exceptions to this criterion. In downtown Minneapolis, we have one substation that houses four transformers to serve the significant load. Similarly, in Bloomington we also have a substation with four transformers to serve the relatively high density of customers in the surrounding area. Generally speaking, this maximum size of three transformers balances substation and feeder costs with customer service, customer load density, and reliability considerations.

Cost considerations include the transmission and distribution capital investment in the lines, load losses (which are generally proportional to line length), land cost, and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access, and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to its ultimate design capacity. Higher levels of DER will affect substation capacity, system protection, and voltage regulation.

Figure 3: Distribution Substation

Feeders are sized to carry existing and planned customer load. Where possible, we design-in redundancy, which has a positive impact on reliability. Feeders have a "range," like a mobile phone service tower, where they can effectively serve. For 15kV, which is common in the Twin Cities metro area, the range is approximately three miles. In rural areas where system load is less geographically dense, the range is higher – approximately one mile per kV. Thus, if customer load density remains the same, then higher voltages can serve a proportionately greater distance.

Feeders typically serve approximately 1,500 customers, though this varies based on voltage, location, customer load density, and the utilization of the feeder. The industry benchmark for feeder capacity is approximately 600 amps, which provides an efficient balance of the costs of conductors, capacity, losses, and performance. This translates to a maximum load-serving capability of about 15 MVA on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

B. Planning Criteria and Design Guidelines

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all customer electric load under normal and first contingency conditions. Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate first contingency capacity allows for restoration of all customer load by reconfiguring the system by means of electrical switching, in the event of the outage of any single element. For example, we generally strive to load feeders to approximately 75 percent of maximum capacity, which provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Adequate substation transformer capacity, no normal condition feeder overloads, and adequate field tie capabilities for feeder first contingency restoration are key design and operation objectives for the distribution system. To achieve these objectives, we use distribution planning criteria to achieve uniform development of our distribution systems. Distribution Planning considers these criteria in conjunction with historical and projected peak load information in annual and ongoing assessment processes.

While the distribution guidelines vary depending on the specific distribution system attribute, there are several basic design guidelines that apply to all areas of our distribution system, as follows:

- Voltage at the customer meter is maintained within five percent of the customer's nominal service voltage, which for residential customers is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to three percent. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.
- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.
- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75 percent of capacity.[1] We developed this standard to help

[1] 34.5 kV follows a 50 percent loading rule.

ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss, because adding load to the remaining feeder circuits would cause them to overload.[2]

All distribution system equipment has capacity, or loading, limits that must factor into our planning processes. Exceeding these limits stresses the system, causes premature equipment failure, and results in customer outages. Our planning processes primarily focus at the substation and feeder levels, but also consider limitations and utilization of other system components such as cable, conductors, circuit breakers, transformers, and more.

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost-effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in our Electric Distribution Standards. We generally discuss our Electric Distribution Standards function in Section VII below.

When we add new feeder circuits to a mature distribution system, we are not always able to maintain minimum spacing between feeder circuit mainline cables due to right-of-way limitations or a high concentration of feeder cables. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks." When feeder circuits are concentrated in duct banks, they experience mutual heating; therefore, those cables encounter more severe thermal limits than multiple buried

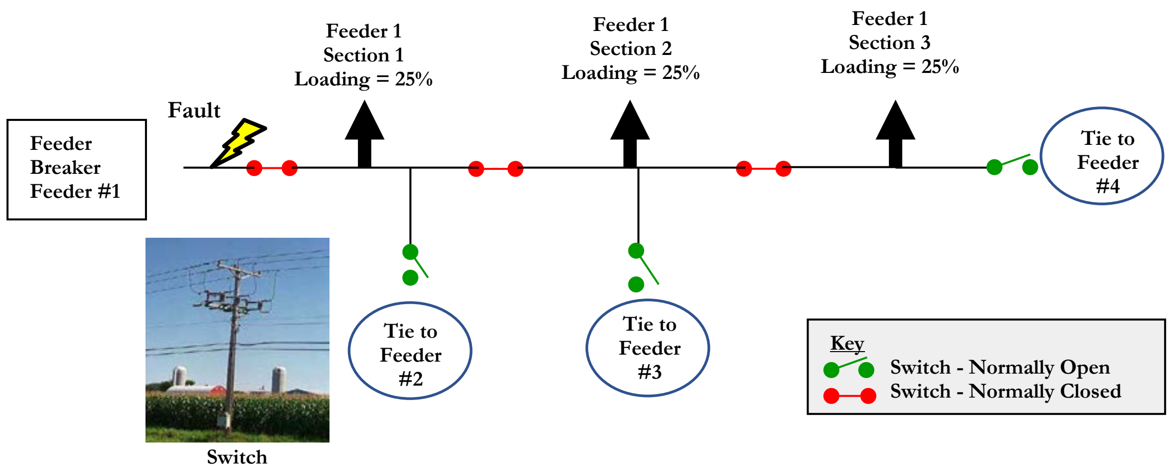
[2] By targeting a 75 percent loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A feeder circuit capable of delivering 12 MVA, for example, should be normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

underground feeder circuits. Planning Engineers use software tools to determine maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct lines, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted. This would require constructing facilities from a different area to serve this load.

As we have noted, our planning criteria aims to maintain feeder utilization rates at or below 75 percent to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. Therefore, to assess the robustness of the system over time, Planning Engineers analyze the historical utilization rates and projected utilization rates based on forecast demand. They generally apply the 75 percent loading guideline when assessing the system across a larger area as part of an area study. The 75 percent guideline is appropriate for these larger area studies because it is often not practical to analyze the section and tie-transfer breakdowns for each individual feeder in each of the identified solution options similar to what is done in our annual planning process. Since the section and tie-transfer breakdowns are highly detailed and specific to the geography and topology of the individual feeders, it is easier to compare and articulate the differences between solution options with a 75 percent loading guideline.

Figure 18 below illustrates this concept with a mainline feeder. The feeder shows the three sections equally loaded to 25 percent of the total feeder capacity. The green and red symbols represent switches that can be operated to isolate or connect the sections of the feeder in the case of a fault. In that circumstance, the feeder breaker in the substation will operate to isolate the feeder where the fault is detected. Then, the normally closed section switches are opened to isolate the section of the feeder in which the fault is detected. Isolating the fault allows a portion of the customers served by that feeder to remain in service while we repair the fault and return the feeder to normal operation.

Figure 4: Typical Mainline Distribution Feeder with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations Mainline Feeder No. 1



In this circumstance, Feeders 1 to 4 all have the same capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders 2, 3, and 4 through the corresponding tie switches. This reconfiguration results in Feeders 2, 3, and 4 each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder #1 sections). This reconfiguration capability maintains electric service to customers while we repair the fault to the feeder and return the system to normal operation.

Area studies are typically initiated on a case-by-case basis, when Distribution Planning identifies a high number of individual risks or loading constraints within a localized area. These localized area studies vary in size, scope, and scale based on the issues identified, and can encompass a single substation, an entire city, or an entire geographic region. When the 75 percent guideline is applied in an area study, it provides an efficient means of approximating how much additional capacity is needed in that area. When the total feeder circuit utilization within the study area exceeds 75 percent (as calculated using Figure 19 below), it is generally no longer effective to perform more simple solutions – such as load transfers or installing new feeder tie connections between existing feeders.

Figure 5: Total Feeder Circuit Utilization in Study Area

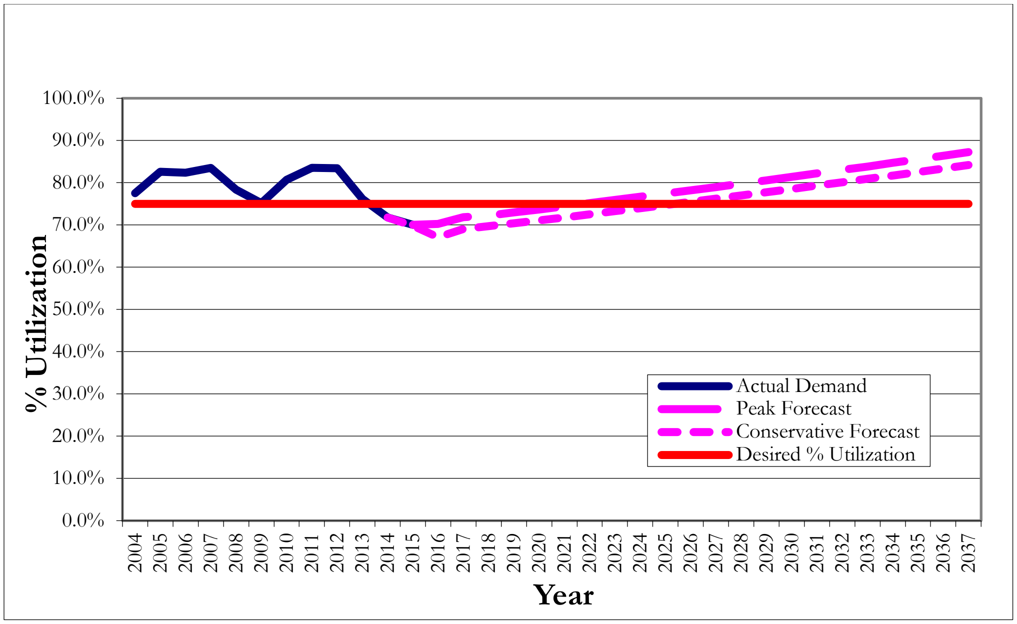
$$\text{Total Feeder Circuit Utilization} = \frac{\sum \text{Feeder Circuit Load in Area}}{\sum \text{Feeder Circuit Capacity in Area}}$$

These simple solutions merely patch a capacity-deficient portion of the system temporarily; rather than solve the issue, they often result in shifting the overloads or contingency risks from one feeder to another. However, when the total feeder circuit utilization is within a reasonable margin below 75 percent, there is generally enough capacity in the area for simple solutions to be viable for resolving any remaining risks.

While a generalized 75 percent utilization is ideal, it may not be feasible depending on system configurations. Feeder utilization in Minnesota is on average 66 percent; approximately 38 percent of the feeders are above 75 percent utilization. When we analyze feeders and transformers, we use the specific loading and configuration to determine the N-0 and N-1 overloads. Because of the wide variety of system configurations, the evaluation may show certain transformers or feeders may be loaded to higher utilization without causing an overload.

The below figure illustrates total feeder circuit utilization for feeders in a study area over a study period timeframe.

Figure 6: Illustrative Total Feeder Circuit Utilization in Study Area – Historical Peak Demand and Peak Demand Forecast



The feeder circuit load history is the actual non-coincident peak loading of all feeder circuits in the study area measured at the beginning of the feeder circuits in the substation. We compare the sum of the individual feeder circuit peak to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. We calculate average load growth for the time period by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period. A peak load forecast starting from the historical peak level provides an upper forecast limit.

Isolated feeder overloads, which can be characterized by an individual feeder overload that occurs when average feeder utilization percentage is *less* than 75 percent, typically occur when there is new development or redevelopment that increases load demand within a small part of the distribution system. Widespread feeder overloads, which can be characterized by one or more individual feeder overloads that occur when average feeder utilization percentage is *more* than 75 percent, typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers, or community initiatives.

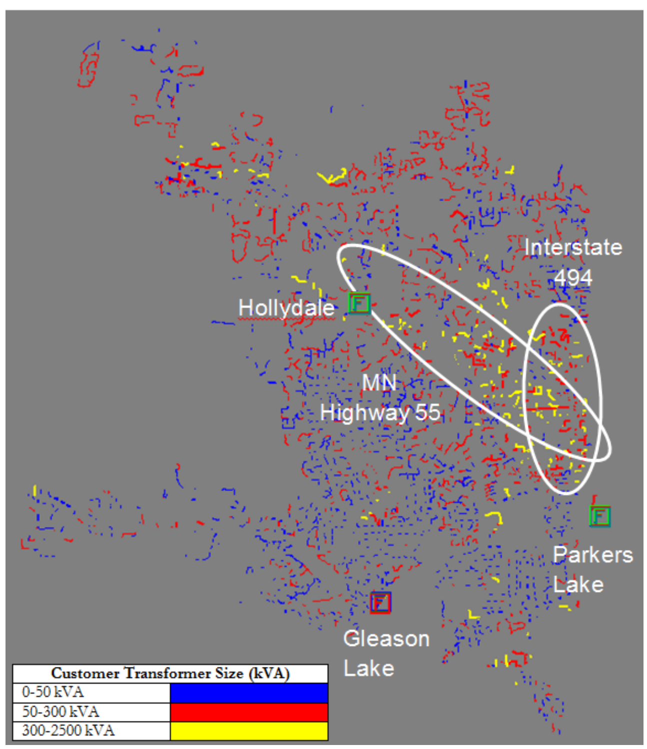
Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped, or focused redevelopment is targeted in an area or along a corridor.

In addition to feeder peak loads, Distribution Planning examines existing feeder load density by studying the distribution transformers serving the customers. Distribution transformers are the service transformers that step the voltage down from feeder voltages to the voltage(s) that the customer receives at their point of service. As customer load grows in developed areas, we change distribution transformers to higher capacity equipment when customer demand exceeds the capacity of the original transformer.

Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand, and are used to help validate the growth that is observed and forecasted in the annual peak demand and load forecast analysis.

Figure 7 below is an example of distribution transformer installation by size from a prior analysis we completed for western Plymouth. This view is helpful to understand present customer load density.

Figure 7: Illustrative – Distribution Transformer Installation by Size



Developed using Synergi Electric

After examining feeder circuit peak demands, we look at the loading levels for the transformers housed at the substations.

Transformers have nameplate ratings that identify their capacity limits. Our internal Transformer Loading Guide (TLG) provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The TLG is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard for transformer loading, ANSI/IEEE C57.92. The TLG consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures, which are the criteria used by Substation Field Engineers to determine normal and single-cycle transformer loading limits that planning engineers use for transformer loading analysis.

A transformer's *normal* loading limit is called the transformer "loadability," which represents the maximum loading that the transformer could safely handle for any length of time. A transformer's *single-cycle* loading limit represents the maximum loading that the transformer could safely handle in an emergency for at most one load cycle (24 hours) and is what we use for our substation transformer N-1 contingency analysis. When internal transformer temperatures exceed predetermined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life." Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

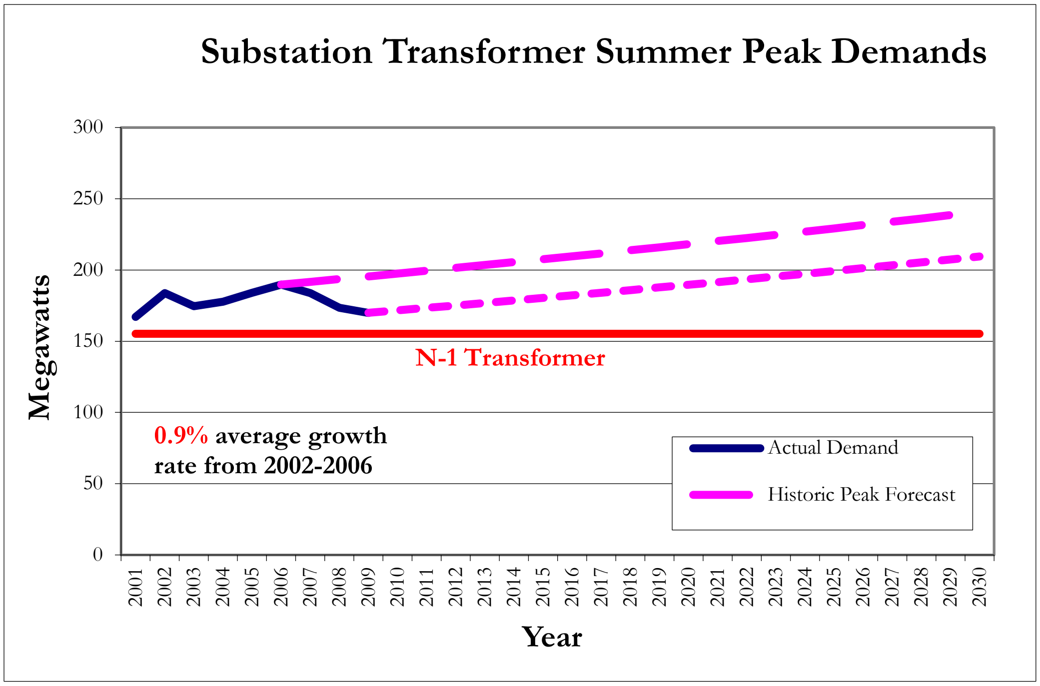
To ensure maximum life and the ability to reliably serve customers, our loading objective for transformers is 75 percent of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75 percent are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization rate, the higher the risk of a transformer outage that interrupts service to customers.

Each distribution substation has a demand meter that is read monthly for each substation transformer. These meters record the transformer's monthly peak. For those distribution substation transformers that have a Supervisory Control and Data Acquisition (SCADA) system connection, we are able to monitor the real-time load on the transformer. Similar to distribution feeders, the transformer data feeds into a data warehouse, which can be combined with hourly historical and forecast peak load data in our new LoadSEER system, so we can view the substation transformer's load history.

Each transformer's peak in a multi-transformer substation is non-coincident – meaning the transformers can each individually experience peak load at different times, and potentially on different days. This is a result of the fact that each transformer serves multiple feeder circuits that each serve different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service due to the larger number of customers affected for any event on a transformer than on a feeder.

Figure 8 below is an example of load growth using historical and forecasted peak loads for a set of substation transformers

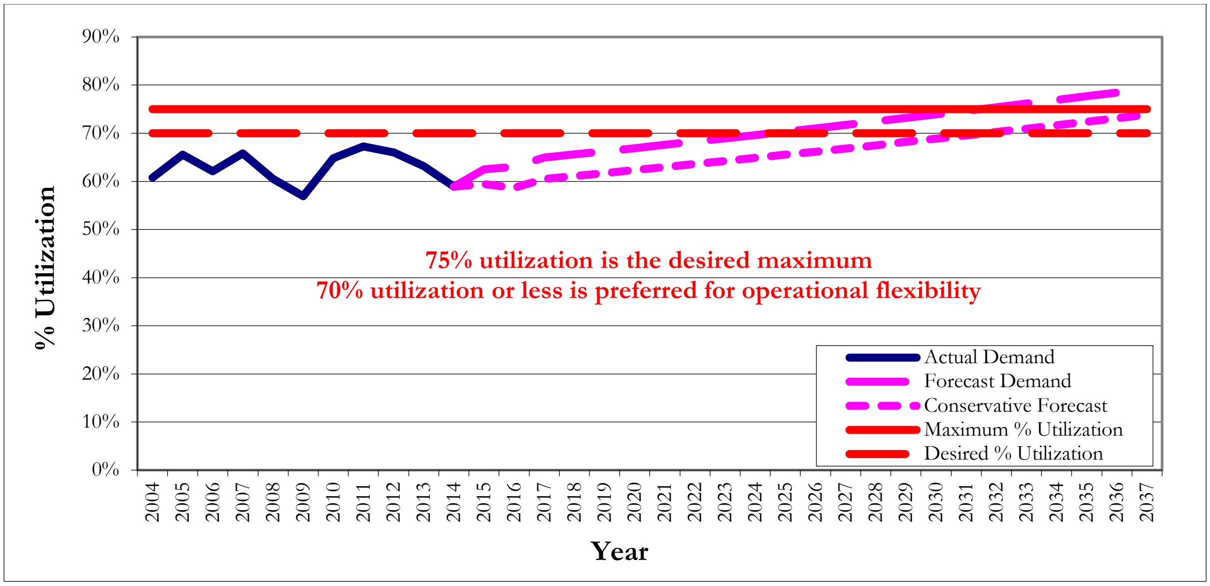
Figure 8: Illustrative Greater Study Area – Historical and Forecasted Loads



The upper and lower dashed lines provide a bandwidth for growth, forecasted from the conservative peak and historical peak values, respectively.

As part of our analysis, we review the loading and utilization rates of distribution substations. We provide an example of our transformer utilization analysis in Figure 9 below, which illustrates the bandwidth of expected load growth that is forecasted to occur between the upper and lower dashed lines.

Figure 9: Illustrative Total Transformer Utilization Percentage for Transformers – Focused Study Area



Even when using conservative peak load levels from the lower dashed line, in this circumstance forecasted load levels still exceed desirable loading levels for the substation transformers in the later years of the 20-year forecast in the study. The range of likely transformer utilization falls between the dashed lines of the conservative forecasted demand and the historical peak forecast load levels.

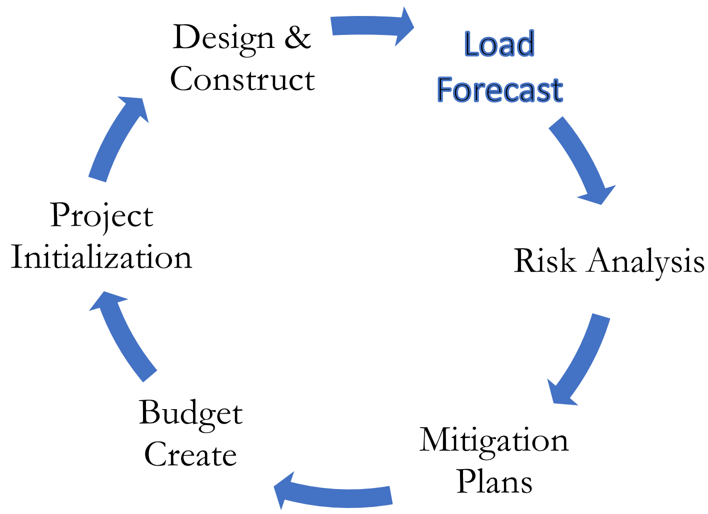
Using the planning criteria such as we have described above, Planning Engineers evaluate the distribution system, and are able to determine transformer and feeder loading and identify risks for normal and contingency operation of the system.

II. DISTRIBUTION PLANNING PROCESS

A. Planning to Meet the Peak Load

We begin our process by forecasting the load for both feeders and substations.

Figure 10: Annual Distribution Planning Process – Load Forecast



In this step, we run a variety of scenarios that account for all the various drivers of load changes. This includes consideration of historical load growth, weather history, customer planned load additions, circuit reconfigurations, new sources of demand (penetration of central air-conditioning, electric vehicles, beneficial electrification, etc.), DER applications, and any planned development or redevelopment.

Then we generate a forecast, aggregate the results, and compare this analysis with system projections. See *Appendix C: Grid Modernization Action Plan* for the load forecast resulting from this analysis in compliance with IDP Requirement D.2, which requires, in part, that we provide our load growth assumptions and how we plan to meet it in our 5-year action plan. We additionally provide our long-term system load projections in compliance with IDP Requirement D.3 in the Action Plan Section of this IDP.

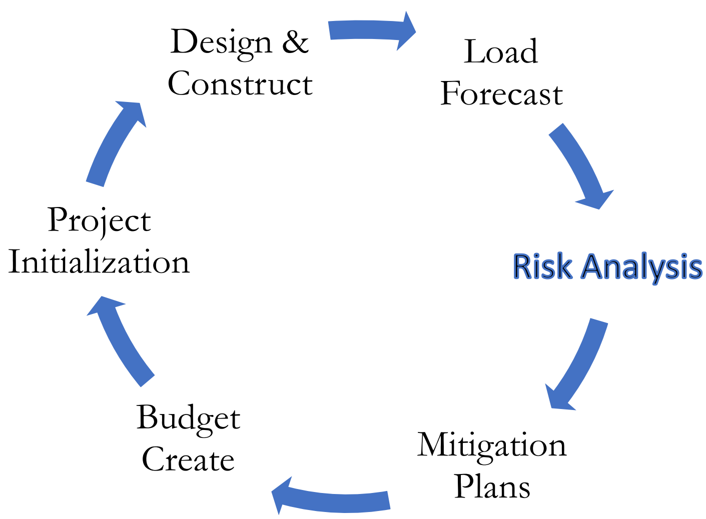
We then provide our distribution forecast to our transmission planning staff, who incorporate the load forecast into their planning efforts. In addition to this load forecast hand-off, we also communicate with transmission regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER at any time of the year, we share that information with transmission. Distribution and transmission personnel also meet twice a year as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system. See Section IV below for additional discussion regarding integrated planning.

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve loads during system peaks.[3] For planning purposes, we define "peak load" as the largest power demand at a given point during the course of one year. Measured peak loads fluctuate from year-to-year due to the impacts of duration and intensity of hot weather and customer air conditioning usage, economic conditions, and other factors. In examining each distribution feeder and substation transformer for peak loading, we use specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Planning Engineers consider many types of information for the best possible future load forecasts including historical load growth, customer planned load additions, corporate energy sales and demand forecasts, DER forecasts, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.

B. Risk Analysis

The next step in the planning process is to conduct risk analyses.

Figure 11: Annual Distribution Planning Process



One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload (N-0) is a concern. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability. For example, a 105 percent N-0 for feeder FDR123 means

[3] When three phase load data is available, we use the highest recorded phase measurement in our forecast.

that the peak load on FDR123 exceeds the limit of the feeder's limiting element by 5 percent.

Additionally, distribution planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer. For example, a 1.5 MVA N-1 condition for feeder FDR123 means that for loss of FDR123, all but 1.5 MVA of FDR123's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk."

Our 2021 to 2025 annual planning process (initiated in Q4 2020), analyzed forecasted 2022 loads and identified the following total risks across NSPM:

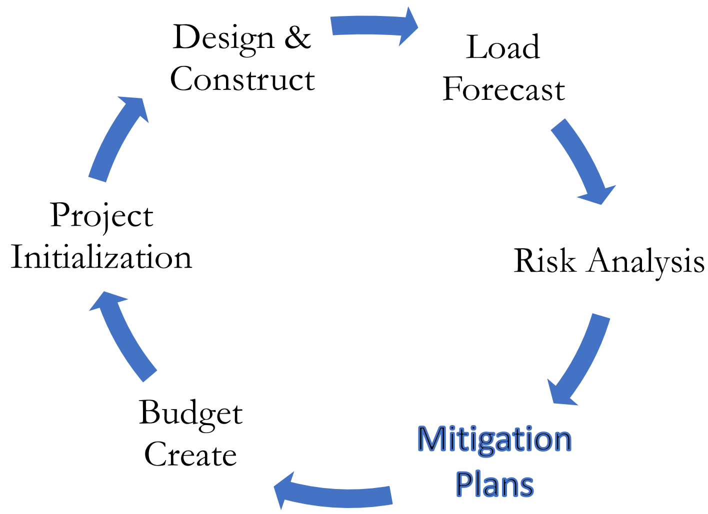
- N-0 normal overloads on 65 feeder circuits
- N-0 normal overloads on 20 substation transformers
- N-1 contingency risks on 566 feeder circuits
- N-1 contingency risks on 151 substation transformers

This process of identifying N-0 overloads and N-1 risks for feeders and substation transformers is referred to as distribution planning's annual "risk analysis." We enter all of these risks into WorkBook, an internal tool used to help rank projects based on levels of risk and estimated costs. We provide our risk scoring methodology and results from the 2021-2025 planning process as Attachment D (portions of which are not public). The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating risks, planning for new customers, and addressing both the aging of our system – as well as preparing it for the future. We discuss how we strike this balance and prioritize projects below.

C. Mitigation Plans

After identifying system deficiencies, the next step in the planning process is developing mitigation plans.

Figure 12: Annual Distribution Planning Process – Mitigation Plans

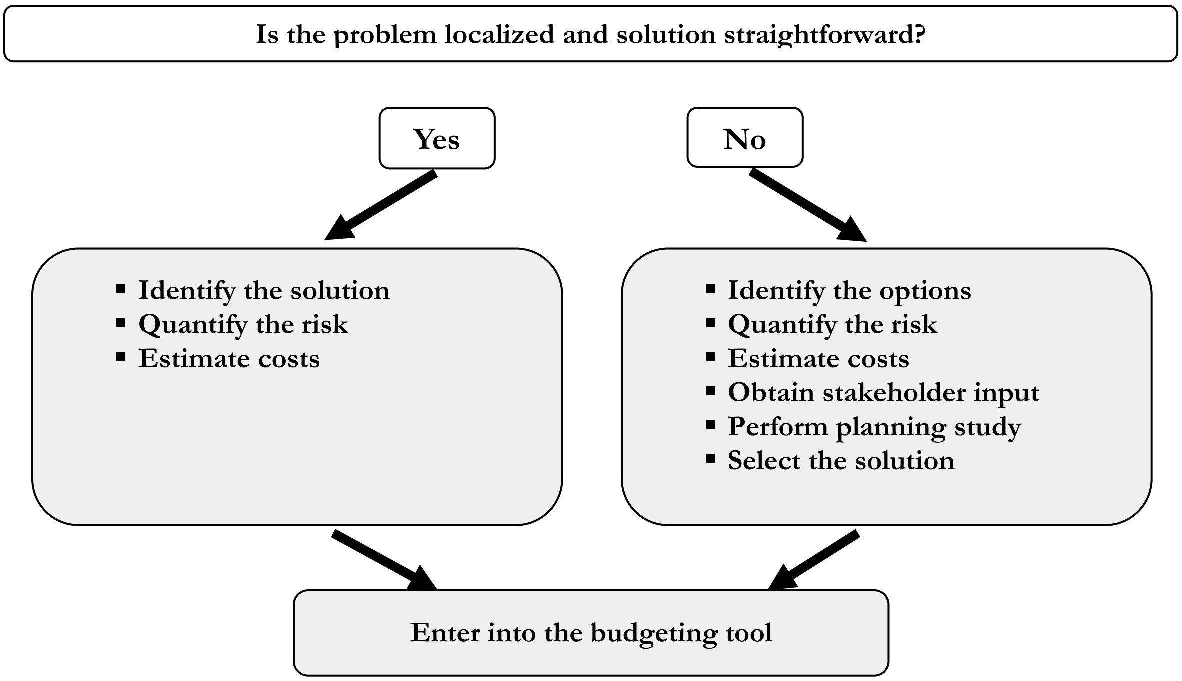


At this step, Planning Engineers identify potential solutions to provide necessary additional capacity to address the identified system deficiencies. We apply thresholds that risks must exceed before we develop a project to mitigate the risk. For N-0 conditions, the overload must exceed 106 percent; for N-1 conditions the load at risk must exceed 3 MVA before we develop a mitigation.

While many of the mitigation solutions are straightforward, others require a detailed analysis. At this point in the process the projects are high level and using indicative unit costs.

The below figure depicts the steps we take to identify potential solutions.

Figure 13: Solution Identification Process



Distribution capacity planning methods address and solve a continuum of distribution equipment overload problems, including isolated feeder overloads, widespread feeder overloads, and substation transformer contingency overloads associated with widespread feeder overloads. Alternatives include reinforcing existing feeder circuits to address isolated feeder circuit overloads, adding or extending new feeder circuits and adding substation transformer capacity up to the ultimate substation design capacity to address more widespread overloads.

Planning Engineers first consider distribution level alternatives including adding feeders, extending feeders, and expanding existing substations. If these typical strategies would not meet identified needs because they had already been exhausted or would not be sufficient to address the overloads, the engineers then evaluate alternatives that would bring new distribution sources into the area. We also evaluate certain projects for potential mitigation by a non-wires alternative (NWA). We discuss this analysis in *Appendix F: Non-Wires Alternatives Analysis*.

If we conclude that distribution level additions and improvements would not meet the identified need, we consider the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands. Ideally, new distribution sources should be located as close as possible to the "center-of-mass" for the electric load that they will serve. Installing substation transformers close to the load center-of-mass minimizes line losses, reduces system intact voltage problems, and reduces exposure of longer feeder circuits and outages associated with more feeder circuit exposure.

Once we identify a mitigation solution for the associated risk(s), we enter the mitigation description, indicative estimated costs, and the risks associated into WorkBook, which uses algorithms to develop a ranking score. The result of this entire step, including any necessary planning studies, is a slate of projects for consideration and review as part of the overall Distribution budgeting process.

1. *Long-Range Area Studies*

If we determine a long-range plan is necessary, we conduct a location-specific study to evaluate various alternatives, which may include DER or DSM. Depending on the scope and scale of the focused study, this process can take weeks or even months, and generally involves the following:

- Identifying the study area (for instance, a single feeder, a substation, or maybe even an entire community or larger).
- Projecting future loads.
- Estimating the saturation of area (limits of development, zoning, etc. on load growth).
- Coordinating with transmission planning to advise them of our work and learn if they have area concerns or projects.
- Generating options.
- Studying and comparing the economics and reliability of the alternatives.

With respect to DSM, we are developing updated methodologies and distribution-avoided costs for energy efficiency.[4] Presently, for assessing distribution impacts, we allocate energy efficiency impacts to each distribution substation and feeder load proportionally based on percentage of system load share. We perform a subsequent summer peak analysis to determine if projects could be deferred. We calculate a deferral value, expressed as $/kW, based on the Xcel Energy corporate cost of capital and using planning level costs for the deferral period. We note that we are also

[4] *See* In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 Conservation Improvement Program Triennial Plans, Docket No. E999/CIP-16-541.

participating in the Minnesota Department of Commerce's Statewide Energy Efficiency Demand-Side and Supply-Side studies, which are examining the future potential for both customers and the Company to reduce peak and energy usage. The Supply-Side study is targeted at utility infrastructure efficiency on the generation, transmission and distribution systems.

These analyses, along with others such as focused long-term area studies, are important complements to our annual planning analysis. We previously provided examples of area studies we have completed, which included non-traditional distribution system solutions.

IDP Requirement 3.A.30 requires that we

> *Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement.*

Order Point 11 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251 requires:

> *Xcel shall file any long-range distribution studies it had conducted in the time since the last IDP.*

We have not completed any long-term area studies since submitting our last IDP. We discuss our NWA analysis that is part of this IDP in Appendix F.

2. Plan comparison standards

If distribution system planning determines a long-range plan is needed, we use the following criteria to compare the potential solutions: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which we describe in more detail below. All alternatives must have the ability to meet existing and forecast capacity requirements.

System performance. System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning). We use Synergi system models to examine loading levels and voltage impacts overall and on specific customers under normal and first contingency conditions. We evaluate performance based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

Operability. Operability is how the alternative impacts the Company's distribution equipment, operating crews and construction crews operating the distribution system during normal and contingency operations. We evaluate operability based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

Future Growth. Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure. For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the area.

Cost. For each alternative, we calculate the present value of all anticipated expenditures required for that alternative to serve the forecasted customer loads. The present value calculations are based on indicative estimates for the proposed alternatives,

Electrical Losses. Electrical losses are most often discussed in reference to the additional amount of generation required to compensate for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

3. *Capacity Risk Project Prioritization*

From this evaluation, projects are assigned a risk score, similar to a cost-benefit ratio. This risk score applies to the mitigation as a whole and not the individual risks that make it up. It is useful for comparing the merits of disparate projects. We then select and prioritize the actual solutions for which we intend to move forward. Attachment E contains a list of our capacity risks, their details, and the projects that mitigate them.

Based on the analysis of alternatives capable of meeting area customer load requirements, we select the alternative that best satisfies the five distribution planning criteria. For example, locating a new distribution substation closest to the greatest amount of customer load and having the shortest feeder circuits would result in the least amount of customer exposure to outages and the best system performance. It might also use the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered – and be the least expensive to construct and has the lowest electrical losses – making it the most cost-effective and efficient option of the four alternatives.

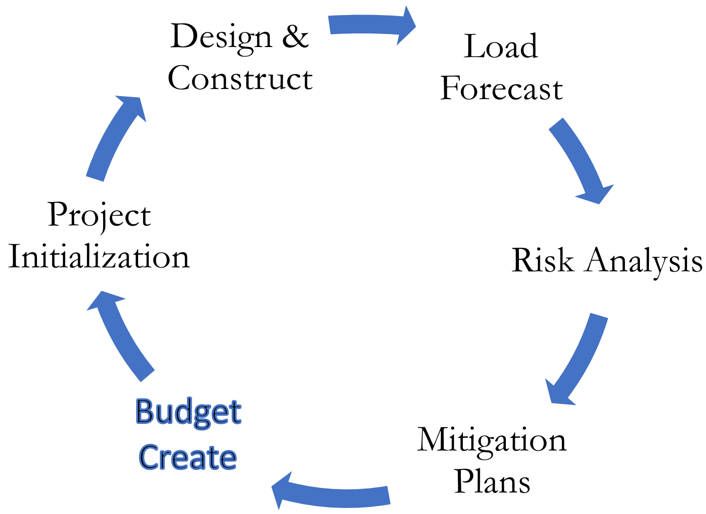
Once we have all the projects identified, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage, and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.).

D. Budget Create

The final step in the planning process before pursuing individual projects is prioritizing the proposed capacity projects into the distribution area's overall budget. At this step, the Company must also provide funding for asset health, new business, and meeting growing customer and policy expectations through support of new technologies and DER.

Figure 14: Annual Distribution Planning Process – Budget Create



The overall budget process recognizes that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. As we replace these key components, we do so with an eye to the future to ensure that the investments we make not only support our customers' needs for reliable service today, but also lay the groundwork for the grid of tomorrow. We must also take steps to implement new systems and technologies that improve our operations and provide customers with more choices related to their energy use. An example of this is investments in our SCADA system, as well as the ADMS we have underway. Together, these systems will provide our engineers and operational staffs significantly improved data from which to monitor and make decisions – all of which benefit our customers in both our planning and response to events occurring on the system.

Given these priorities, we must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by storms, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

As capital spending is determined and, throughout the year as new issues are identified, each operating area 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 a software tool we developed and use to track and rank projects based on the inputs provided – including 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 we generally consider to prioritize investments are as follows:

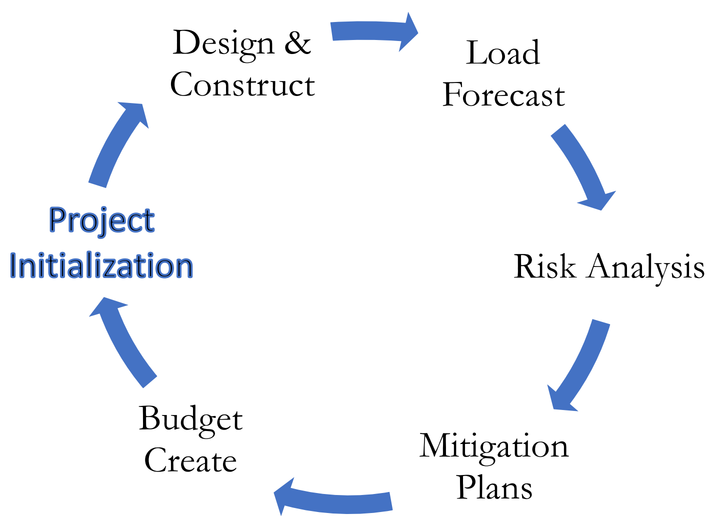
- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities,
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated,
- *Environmental* – Evaluation of compliance with environmental regulations. 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. We accomplish this by ranking the assessment of each project against each other. The 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. We note that we must also apply judgment in the prioritization process. An example of this is two competing new feeder projects – one in the metro area that only involves a short distance, and the other in a rural area that involves installing infrastructure for two miles. The cost of the rural example in this circumstance is higher, and the benefits of the two projects are the same – so the metro project would score higher. However, the rural project is also needed. Our process therefore contemplates some back-and-forth with the planning engineers to validate priorities.

E. Project Initialization

After the capital expenditures budget is finalized, the approved project list becomes the basis for the release, or initiation, of projects during the calendar year.

Figure 15: Annual Distribution Planning Process – Project Initialization



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.

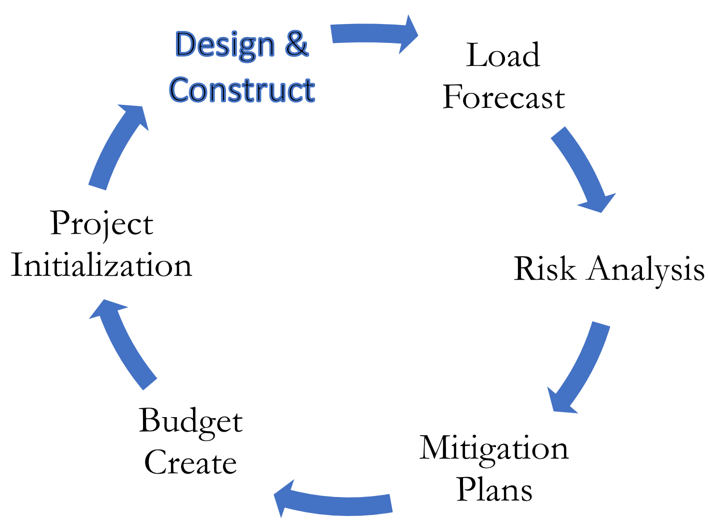
Distribution Planning takes the approved capacity projects stemming from this process and communicates them with design and construction. The Planning team continues to participate in the ongoing capital budget processes, as the Distribution business responds to changing circumstances, and interfaces with design and construction to adjust priorities as needed.

Once the five-year budget is determined, the Planning Engineers write Electric Distribution Planning (EDP) memos for the first two years of approved capacity projects. An EDP memo is a high-level step-by-step description of the project that will mitigate an identified risk. The memos describe the problem, the substation design/construction steps to take (if any), and any distribution line design/ construction steps to take. The memos provide maps and text specifying where to place switches, capacitor banks, or where to cut into another feeder to transfer load to a new feeder. These memos initiate the design and construction portion of the project.

F. Design and Construct

Finally, the selected projects are communicated to substation engineering and distribution engineers and designers who bring the projects to life.

Figure 16: Annual Distribution Planning Process – Design and Construct



At this step, these engineers and designers perform detailed design work and initiate their construction. We summarize the groups generally involved and their roles below:

- *Substation Engineering.* If a project requires a new feeder bay at an existing substation or a new substation entirely, this group performs the detailed engineering, design and construction.
- *Distribution Design and Construction.* This area performs the permitting, design, and construction of new feeder circuits or modifications of existing circuits.

Ideally, projects can be implemented precisely as envisioned by Distribution Planning, but often this is an iterative process.

III. CURRENT PLANNING TOOLS

A. Current Planning Tools Suite

Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. In this section, we discuss our current planning tools in compliance with the following requirement. One significant change since our last filing is that DAA is no longer one of our planning tools and has been replaced with our new advanced planning tool, LoadSEER.

IDP Requirement 3.A.1 requires the following:

> *Modeling software currently used and planned software deployments.*

Table 1 below summarizes the tools and how we use them in our planning process. We then discuss in more detail how we use each of the tools.

Table 1: Planning Tool Summary

Tool	Process	Description
DNV-GL Synergi Electric	Power flow	Contains a geospatially accurate model of the electric distribution Feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system.
Integral Analytics LoadSEER	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	Analyzes historical SCADA and weather data to determine typical annual loading, and simulates impact of load and DER growth to develop a load forecast for feeders and substation transformers out 10-30 years. This is also the system of record for historical peak feeder and substation transformer load information.
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years.
CYMCAP	Determines normal and emergency ampacity for Feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded.
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as Feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution Supervisory Control and Data Acquisition (SCADA)	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers.
WorkBook	Project Prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs.
PI Datalink	Load Forecast	Tool used in conjunction with Excel to help us determine our minimum loads, as well as our gross peak and minimum loads for feeders and transformers that have generation on them.

We additionally outline our hosting capacity tool that is not currently part of the annual system planning process.

Table 2: Hosting Capacity Tool

Tool	Process	Description
Electric Power Research Institute Distribution Resource Integration and Value Estimation (DRIVE)	Hosting capacity	Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine an indicative range of minimum and maximum hosting capacity by screening for voltage, thermal, and protection impacts.

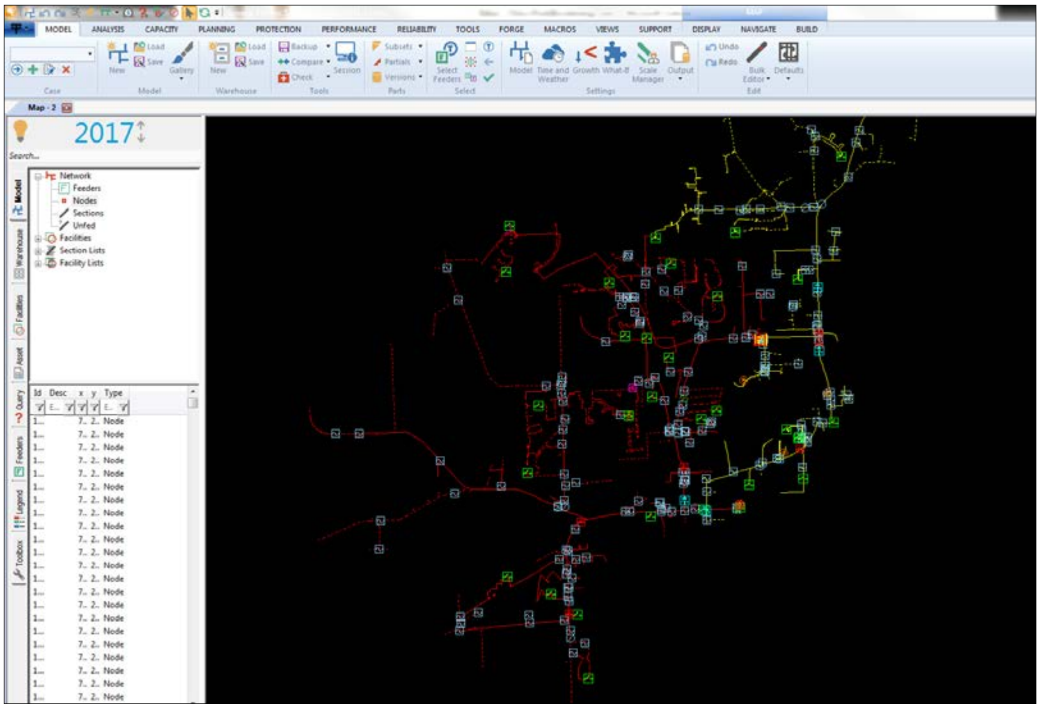
Table 3: Tool Summary by Distribution Planning Process

	Planning Process Component						
Tool	**Forecast**	**Risk Analysis**	**Mitigation Plans**	**Budget Create**	**Initiate Construction - EDP Memo**	**Long-Range Plans**	**Hosting Capacity**
Synergi Electric			X			X	X
LoadSEER	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
PI Datalink	X						
DRIVE							X

DNV-GL Synergi Electric. Synergi is the Company's distribution power flow tool, which we use to model the distribution system in order to identify capacity constraints, both thermal and voltage, that may be present or forecasted. It provides a geospatially accurate model of the electric distribution feeder system with known conductor, electrical equipment, and facility attributes such as material type, which contains ampacity and impedance values. We use it to model different scenarios that occur on the distribution system and to create feeder models that are an input to the DRIVE tool used for hosting capacity analysis; it can also be used to explore and analyze feeder circuit reconfigurations. As load is manually allocated to a feeder and we run a power flow process, exceptions such as voltage or thermal violations may occur. Areas of the feeder are then highlighted due to those exceptions to bring these issues to the engineer's attention.

Synergi can generate geographically correct pictures of tabular feeder circuit loading data, which is achieved through the implementation of a GIS extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. We provide a screenshot from Synergi as Figure 17 below.

Figure 17: Synergi Electric Application Example



To calibrate the model, we import peak day customer usage data into the system, and allocate it to service transformers or primary customer service points. The Customer Management Module within this software takes monthly customer energy usage data and assigns demand values based on the customer class (i.e., residential, commercial, etc.), the assigned "load curves" for that class, and the desired time period. This is done feeder-wide, so that all customers are accounted for. When historical or forecasted peak load data is added from the LoadSEER software package, Synergi is capable of providing power flow solutions for the given condition. At that point, we can also scale the loads up or down across the entire feeder depending upon the estimated demand and scenario need.

The "load curves" that are being utilized come from our load research department and represent different customer classes on a state-by-state basis. They are not used to analyze different loading scenarios throughout the day, but rather to attribute more accurate peak demands at locations across a given feeder.[5] Ultimately, Synergi helps engineers plan the distribution system through modeling. It allows the ability to shift customers and load around, as well as add new infrastructure to simulate future additions to the system. It also can model distributed generation sources, such as solar or wind, so that those affects can be better accommodated.

Integral Analytics LoadSEER. We use LoadSEER for medium to long-range load forecasting of distribution feeders and substation transformers. The LoadSEER system is the historical peak system of record for those distribution elements. LoadSEER also analyzes historical SCADA, customer billing, and weather data to determine the typical annual hourly loading on each feeder and substation transformer. The tool combines this typical loading with a simulation of load and DER growth to develop an annual load forecast 10 to 30 years into the future.

Once our forecasted loads are updated every year, we use LoadSEER to create a peak substation load report for Transmission Planning and Transmission Real Time Planning. We also use these forecasts in our risk analysis evaluation, long range plans, and to populate models in Synergi for various purposes. LoadSEER is also a repository for feeder and substation transformer capacity limits that we use to identify areas of the system where there are capacity constraints. These limits are also passed on to Distribution Operations to ensure the correct notifications occur in the Control Center for any potential overloads.

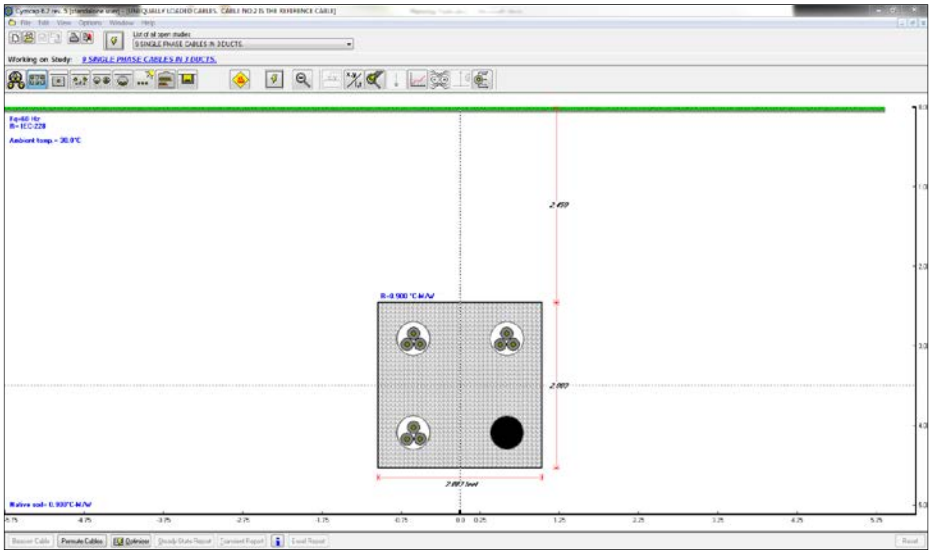
[5] For example, it ensures a potential residential customer receives more load at peak than a potential industrial customer with the same energy usage. This is because industrial customers typically have a flatter load profile curve. Accordingly, when industrial customers are compared to residential customers they have more consistent loading throughout the day and have less influence on the peak than the residential customer.

Figure 18: LoadSEER Application Example

Microsoft Excel Spreadsheets. We use Microsoft Excel spreadsheets to perform feeder and substation transformer contingency planning. A key part of distribution planning is identifying risks, not only for normal operating situations, but also for situations where the system is in a contingency state; that is not whole. This helps in creating a system with flexibility. To do this we use a series of spreadsheets that include the tie points to other feeders and the capacity that is available at peak times through those tie points. While this is fairly simplistic tool, these spreadsheets provide valuable information about our system that we call "Load at Risk" that we use to justify projects that keep our system reliably robust.

CYME CYMCAP. Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amount of amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP takes into account appropriate factors in determining these values, such as duct line configuration, soil conditions, and cable properties. Unlike overhead conductors that are exposed to the air and wind, underground cables have a tougher time dissipating heat. To ensure the cables are not overloaded, we model the true ampacity of them with the help of this program.

Figure 19: CYMCAP Application Example



General Electric Smallworld Geospacial Information System. Our GIS contains location-specific information about system assets and provides the connectivity model source data and feeder topology to Synergi, as well as other data to many other applications within Xcel Energy. The GIS allows us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.

GIS is also very helpful in capturing changes to the distribution system that may not always be visible to all. For example, we rely on GIS to show changes that would occur as the result of a new Community Solar Garden (CSG) installation. Any upgrades to the feeder that occurred as a result of that addition plus the details of the new CSG itself, would be added into GIS. This would then be used to update our Synergi models for accurate modeling going forward.

Distribution Supervisory Control and Data Acquisition. Our SCADA system provides information to control center operators regarding the state of the system, provides appropriate alarms (including outage notifications), and provides for remote control of substation and certain field equipment. For operational purposes, every few seconds it provides system status information, such as operating parameters for our generation and substation facilities. It monitors and collects system performance information for feeders and substations used to ensure the system is safely and efficiently operating within its capabilities. This performance information is also used by planning engineers to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability. Given the importance of SCADA capabilities to reliability and load monitoring, in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at 3-5 substations per year. As discussed in more detail in the MYRP rate case filed concurrently with this IDP on November 1, 2021, starting in 2022, the Feeder Load Monitoring Program aims to complete the rollout of SCADA at most of the remaining substations in Minnesota.

For feeders where we have SCADA capabilities, we are able to monitor the real time average or three phase amps on the feeder for operational purposes. For planning purposes, the SCADA system collects enough information throughout the course of a year to determine daytime minimum load and peak demands for all feeders that have this functionality. However, it takes some manual effort beyond collecting the data to adequately decipher those values.[6] The data is maintained in a data warehouse and combined with the historical LoadSEER hourly load data. When three phase load data is available, we use the highest recorded phase measurement to determine facility loading.

Access Database WorkBook. To help rank projects and perform cost-benefit analyses, we use an internally-developed Microsoft Access Database tool called WorkBook. This tool allows us to input our distribution system risks along with the proposed mitigations and their indicative costs that are intended to solve those risks. Algorithms in the tool result in a ranking score that helps to incorporate these projects in the budgeting process. The primary risk inputs that planning engineers develop for entry into WorkBook includes N-0 and N-1 risks for feeders and substation transformers. However, other inputs such as asset age and historical failures are also considered, which further aids prioritization of the projects as part of the budget process.

PI Datalink. A Microsoft Excel add-in that provides SCADA information from our equipment in the field. We utilize the data from this tool in our analyses for load forecasting, minimum daytime loads, and community solar gardens. By having this tool in Microsoft Excel, we are able to streamline complex and repetitive calculations. As a result, we gain better visibility of the distribution system which in turn enables us to make more informed decisions about how to mitigate risks.

[6] This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults or other disturbances on the feeder.

B. LoadSEER Advanced Planning Capabilities

In response to the fundamental changes occurring on the distribution system, we recognized a need and sought a new tool to aid in developing a load forecast and distribution plans that would allow for enhanced analysis.[7] as customer adoption of DER increases and our distribution system becomes more dynamic – as analyzing based on the annual peak load view is no longer adequate. Further, we were using a patchwork of tools to meet Commission requirements regarding scenario analysis, and even then, our capabilities to do scenario analysis were limited. Increasing penetrations of DER on the distribution system require Distribution Planning to better understand the conditions of the distribution system at a more detailed level – this could include hourly profiles in some cases for both feeders and substation transformers.

The Commission certified LoadSEER in our 2019 IDP proceeding, and we are now using it in our planning process. As a certified grid modernization investment, we are seeking cost recovery through the Transmission Cost Recovery (TCR) Rider, and will include a detailed discussion of the tool, our implementation, and our functionality roadmap in our upcoming TCR Rider Petition. We provide a summary of that information here, to give context to our use of LoadSEER in relation to the Commission's IDP requirements and expectations.

1. Forecast Granularity and Non-Wires Alternative Investment Analysis

LoadSEER enables granular analysis options including both time intervals and proximity to customer end points, enabling us to make more accurate decisions regarding investment needs and options. For example, with the introduction of DER onto the system, the differentials between minimum and maximum load during the day become both a more valuable and harder to predict data point. With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or at a different time of day than another feeder or than the system as a whole. In order to adequately assess the impact of DER on a given part of the grid, therefore, we need a tool that can forecast hourly load at the selected analysis point. Further, the most granular analysis point we have

[7] Pursuing and implementing LoadSEER as part of our 2019 IDP was also responsive to Order Point No. 7 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, which required the Company to: "Make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP."

been able to utilize in distribution planning prior to LoadSEER is the feeder level, but there may be value in analyzing sub-feeder data. Each feeder is generally associated with approximately 1,500 to 8,000 endpoints, depending on the area's population density. However, as DER are often localized to a specific end point, being able to analyze load and generate distribution forecasts at a sub-feeder level may provide valuable insights for both necessary grid upgrades and future potential customer offerings.

These more granular analyses will provide important information and efficiencies in assessing potential NWA to identified system upgrade needs. An annual peak load analysis alone cannot communicate whether an identified upgrade is a candidate for non-wires alternative; more granular hourly data is required to determine the magnitude of overloads at specific durations. Without LoadSEER this analysis was completed by extracting historical peak day load curves from feeder data, scaling them to the forecast study year, and then manually evaluating the normal and contingency load conditions. We then used these results to conduct risk analyses and develop theoretical load conditions if certain DER solutions were applied. However, LoadSEER's capabilities to evaluate and project hourly load data on a feeder or other specific point on the grid facilitates more efficient evaluation of potential future overloads and whether a non-wires solution – such as DER, energy efficiency or energy storage – is a viable alternative to traditional upgrades. In short, we LoadSEER will reduce manual work and better identify opportunities for DER to provide value on our grid.

2. *Scenario Development*

The Commission's Orders setting out the requirements for our IDP includes DER scenario analyses. In accordance with these requirements, we evaluate scenarios with a minimum level of assumed DER adoption, as well as medium and high adoption scenarios (corresponding to Base+10 percent and Base+25 percent, respectively). The objective of these analyses is to understand whether substantially increased levels of DER at a given point on the grid would result in different system overload conditions and upgrade needs. These scenarios are developed and evaluated outside of our load forecasting tool. However, LoadSEER is capable of efficient forecasting processes and better assessment of how the increased adoption scenarios would affect specific feeders and substation transformers. This will be particularly important going forward as DER and beneficial electrification adoption increases in our service area.

3. *Aggregation and Integration with Other Resources and Planning Processes*

Finally, a key aspect of LoadSEER is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes and its ability to handle data inputs from various sources beyond traditional inputs such as feeder-level SCADA data and existing customer usage inputs. For example, external data layers, such as more targeted economic and weather forecasts or projected DER adoption trends will help us more effectively forecast load changes into the future. LoadSEER also importantly is able to integrate potential internal future sources of data, such as interval data from our future AMI metering as we implement that with our customers.

Further, LoadSEER provides essential forecast aggregation and integration with other company planning efforts. Historically, our DAA tool would evaluate potential load growth on a feeder or substation, however, the planner responsible for analyzing that specific point on the grid had to define the level of growth. LoadSEER automates that process and aggregates forecasts from each point of analysis to ensure a reasonable fit with Company-wide top-line forecasts. Finally, LoadSEER facilitates improved accessibility and usefulness of forecast information with other planning functions, which is also an internal goal and IDP requirement (i.e., aligning distribution planning to integrated resource planning more closely, particularly in terms of DER forecasts). For example, in the past, our transmission planners had to scale distribution forecasts to the corporate level manually for use in transmission planning processes and tools. As our resource planning tools evaluate generation resources at an hourly level, a similarly granular distribution forecasting tool helps to facilitate this integration more effectively than previous manual translation processes.

4. *Impact of the LoadSEER on other Distribution Planning Processes and Tools*

LoadSEER is able to generate, along with a load forecast, a forecast of daytime minimum loads (DML) for the various endpoints analyzed. DML are required information for DER interconnection studies, as well as hosting capacity analysis. This greatly simplifies and automates an otherwise manually-intensive process of building custom SCADA queries for each endpoint and manually parsing through the data to determine the DML. Additionally, LoadSEER has the ability to export forecast results directly to load flow programs, such as Synergi Electric. This will improve the efficiency of the load flow model build process, which is performed to build models for planning studies and hosting capacity analysis. LoadSEER is able to make these improvements to the distribution planning process largely due to the fact that it ingests and outputs a significantly larger set of data as part of the forecasting process. We expect that as we gain experience with LoadSEER, we will begin to find other ways to use it and its data to further benefit our processes and customers.

Finally, we note that the Commission required the Company to make tracking and updating actual feeder DML a priority in 2019 – and in our 2019 IDP, we discussed our efforts to do that. Through this large effort, we determined and updated historical DML for all of our feeders and substation transformers that have load monitoring. We now maintain DML information in LoadSEER and make updates to DMLs for individual feeders and substation transformers on an as-needed basis. We note that we will also be tracking DML and any changes to them year-to-year. LoadSEER will also aid in the actual forecasting of these values going forward. Minimum load forecasting is a newer concept, but LoadSEER will allow us the ability to forecast future load curves and the peak and minimum values associated with them.

C. Industry

It has been helpful to be involved with various distribution grid research efforts throughout the industry. Our membership with the Electric Power Research Institute (EPRI) has played an important role in helping us keep abreast of innovations in technology in the areas of grid modernization, reliability, integrated planning, solar integration, battery storage and DER interconnection. We participate in several research programs in these areas and are able to learn and share the latest developments with other industry members.

EPRI was key in working with the industry to develop PV hosting capacity tools and we are also excited about their interest in developing other planning tools. EPRI's objective is to develop a more automated and comprehensive platform that performs more robust scenario analysis for various grid investment decisions including non-wires alternatives. EPRI's long-term vision is to develop processes and prototypes that are incorporated and adopted into commercial planning tools.

The National Renewable Energy Lab (NREL) is also conducting research in similar areas and we have had the opportunity to collaborate with them on various research projects. Some of the efforts with NREL and EPRI include:

- We are working with NREL on a research project designed to look at the impacts of unmanaged EV charging on the distribution system. Various mitigation options such as managed charging and Time of Use rates, are being studies as well. We are exploring opportunities of working together on future initiatives that would be a continuum of this work.

- Through EPRI, we are participating in an industry working group associated with DER interconnection standards and practices. A primary area of focus is discussing challenges with new options, technical requirements and responsibilities associated with adoption and application of IEEE 1547-2018.
- We are participating in an EPRI supplemental project with other utilities where EPRI will try to identify "best fit" smart inverter settings based on various feeder model types. Results will be available in late 2022.

IV. INTEGRATED DISTRIBUTION–TRANSMISSION–RESOURCE PLANNING

In this section, we discuss the present state of Distribution, Transmission, and Resource Planning and our longer-term view of how we envision them becoming increasingly integrated.

IDP Requirement 3.A.5 requires the following:

> *Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans.*

As we discussed in our recent Reply Comments in our IRP proceeding in Docket No. E002/RP-19-368, the Company, and the industry more broadly, are undergoing a significant transition – not only in terms of the types of resources we consider, but also the way in which planning is conducted.[8] As the transition of our fleet continues, there are improvements we can make to our analysis and modeling approach to better incorporate a broader set of resources and integrate planning across our system. We recognize that coordination between these processes needs to be stronger, and we have begun that work.

Today, the work we are doing on customer adoption-based DER and electrification is helping to bring these planning processes closer together. For example, we are using the same system-level DER and EV forecasts in all of our planning processes. Distribution planning also formally meets with Transmission planning at least twice per year, and supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the

[8] *See* Xcel Energy Reply Comments, Section 4: Modeling and Rebuttal (June 25, 2021).

distribution system – and similarly with interconnections that may affect other parts of the system – distribution takes the lead and involves other planning resources as needed. Finally, we also coordinated between distribution and resource planning in the work that we did in 2021 to examine potential additional values associated with non-wires alternatives (NWA) analysis – and some of the changes we propose to implement with our 2022 NWA analysis come directly from what we do for IRP.[9]

It is important to note that there are fundamental differences in these planning processes that will continue to challenge integration at least in the near-term, but we recognize the value. Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful – as will integrating distributed resources into the IRP process. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. These statutes and rules prescribe the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings. These processes work for IRPs due to the long-term nature of macro resource additions and changes. However, distribution planning is more immediate; its full planning horizon correlates to the five-year action plan period of an IRP, which is generally a continuation of past IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, a primary consideration in distribution planning is the immediacy of ensuring customer reliability.

That said, while the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Planning processes will become more integrated and wholistic. Our current IRP proceeding saw significant stakeholder engagement and interest in distributed resources; this IRP was also the first to have multiple parties in addition to the Department of Commerce offer modeling – including resources at the distribution level. However, as we explained in our Reply Comments in the IRP proceeding,

[9] *See* Appendix F of this IDP.

additional work is necessary to determine an appropriate methodology to incorporate distributed resources into IRP modeling.

We support the evolution of the grid. We also support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. There is some movement nationally in this direction, but no one has figured it out yet. In addition to figuring out the right frameworks, methodologies, and mechanics – we expect that the increasing complexity of our industry and integrated planning paradigms will require a rethinking of the current regulatory framework to ensure it remains aligned. Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. So, while a national perspective and other state actions may provide helpful points of reference, we believe this evolution should occur at a measured pace that correlates to Minnesota policy objectives and customer value. We are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations.

APPENDIX A2: STANDARDS, ASSET HEALTH, AND RELIABILITY MANAGEMENT

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

We are reaching the point where many of our assets are at or are past their anticipated useful life. As a result, we are planning greater investments in Asset Health and Reliability to replace assets that are in poor condition, like our overhead poles, and that we are able to replace assets closer to their estimated useful life, like substation transformers. These investments allow us to maintain reliable service for our customers and to harden our system as appropriate to make it more resilient to extreme weather events.

In this Section we describe several analyses and functions that support distribution system reliability and resilience.

I. ELECTRIC DISTRIBUTION STANDARDS

Utility distribution systems are complex and dynamic, in that they involve thousands of pieces of equipment, must be resilient from outside forces over vast areas of geography, and must be able to respond to changes in customer loads and operational realities. Traditionally, distribution systems have been designed for the efficient distribution of power to provide customers with safe, reliable and adequate electric service – with geography playing a significant role in the design of the system. Our Minnesota service area has diverse geography and therefore diverse planning criteria and considerations.

One of the ways we plan the system is through a set of materials and work practice standards that apply to the construction, repair and maintenance of the electric overhead distribution, underground distribution, and outdoor lighting systems. The purpose of Electric Distribution Standards at Xcel Energy is to develop and maintain a broadly accepted set of material and construction standards that meet the needs of each of the operating companies and stakeholders, while meeting all applicable regulatory and code requirements. The Standards function acts as an expert consultant to operations and engineering, collaborates to enhance public and employee safety, drives cost-effectiveness, and improves system reliability through defining electric distribution standard materials, methods, and applications.

Standards updates may stem from a number of circumstances including regulatory or code changes, company analysis, input or an issue raised by field personnel, and industry guidance, among others.

Xcel Energy's Design standard books consist of Overhead, Underground, and Outdoor Lighting Manuals. Each of these Manuals detail equipment and designs that have been previously reviewed against industry standards and best practices to ensure installation of facilities results in safe and reliable service. Documenting approved materials and equipment configurations allows for efficient design of construction projects. The Standards Manuals simplify electrical distribution projects and optimize a Designer's work because the engineering and code compliance is built-in – and typically only requires engineering input for special circumstances. Reference material on transformer sizing and conductor lengths, which already accounts for voltage and thermal limits, is also part of the Standards Manuals.

We are providing a couple of examples of the work that Standards does, to further help put the Standards function into context:

Porcelain Cutout to Polymer Cutout Transition (2010-present day). Xcel Energy has a process to identify and analyze faulty material. In this case, material submitted from field crews and engineering identified an issue where porcelain cutouts stood out from other materials as having issues requiring further analysis. We had been using polymer cutouts in specialized applications, however not broadly, because industry standards had not yet been developed for the polymer material. We validated our observations on the porcelain cutouts and the potential viability of polymer as an alternative through peer group consultation with other utilities through Midwest Electrical Distribution Exchange and Western Underground Committee.

Electric Distribution Standards worked with local jurisdictional teams with an objective to identify and vet a polymer cutout to be used company-wide, and discontinue the use of porcelain cutouts. We additionally participated in the IEEE C37.41 and C37.42 revision to create testing requirements for polymer cutouts. We further improved this Standard by consolidating 125kV BIL to 150kV BIL cutouts – allowing a transition from three cutout types to two cutout types, and increasing the number of manufacturing sources from which we can procure polymer cutouts that meet our standards requirements. As we systematically replace remaining porcelain cutouts on our system with polymer, we are improving reliability for customers and the resilience of our system. This change also expanded material availability and resulted in cost savings.

Wood to Fiberglass Crossarm Transition (2010-present day). In 2011, the National Electrical Safety Code (NESC) changed the loading requirements for deadend crossarms. We conducted research with our industry peer groups and found that fiberglass was identified as being the best material for longevity and strength. We evaluated alternatives, and available fiberglass deadend crossarms met the NESC requirements and resulted in an approximate 17 percent cost savings. After our success implementing deadend fiberglass crossarms, we evaluated and ended-up implementing fiberglass tangent crossarms as a cost-neutral option – improving the resilience of our system in a cost-conscious way for our customers.

We have since made further improvements to the fiberglass crossarms after participating in an EPRI initiative to evaluate system materials in terms of system hardening. After conducting further internal research, to develop testing criteria based on galloping and ice loading witnessed by Xcel Energy line crews and Electric Distribution Standards, we updated Xcel Energy standards to obtain a better and longer life product – and are additionally working with the fiberglass crossarm industry to revise the national standards to better take these conditions into account.

For additional context, Table 1 below shows a list of some of the most common industry standard documents applied in distribution engineering. The list is not intended to be inclusive of all standards that may be applied to medium and low voltage systems, but rather is intended to provide insight into standards that are frequently used. Included are primarily documents from the Institute of Electrical and Electronics Engineers (IEEE) which are classified as Standards, Recommended Practice, and Guides. Standards carry more weight when compared to Recommended Practices. Guides often show a number of ways to achieve a technical objective and are the least prescriptive.

Table 1: Common Engineering Standards Summary

Condition	Standard
Safety	National Electric Safety Code (NESC)
	Xcel Energy Safety Manual
Voltage Limits	ANSI C84.1 – minimum and maximum voltage limits, voltage imbalance limits
	Xcel Energy Standard for Installation and Use – voltage limits and imbalance (same as ANSI C84.1)
Thermal limits	Xcel Energy Design Manuals (Distribution Standards Engineering)
	Substation Field Engineering (SFE) transformer loading database – based off of IEEE standards
	IEEE 738 – Overhead conductor ampacity rating IEC 287 and IEC 853 – Cable ampacity rating methodology in CYMCAP program
	IEEE C57.91 – transformer and regulator loading guide IEEE C57.92– power transformer loading guide
Distribution Interconnection	IEEE 1547 – Interconnection of Distributed Resources
Harmonics	IEEE 519 – total harmonic distortion and individual harmonic limits
Voltage Fluctuation	IEEE 1453 – rapid voltage change and flicker limits

Additionally, North American Electric Reliability Corporation (NERC) standard FAC-002-2 applies to studying the impact of interconnecting facilities to the Bulk Electric System, which comes into play with distribution substations. Specifically, Requirement R3 applies when we seek to interconnect new “end-user facilities” or materially modify existing interconnections to the transmission system. It states we shall coordinate and cooperate on studies with our Transmission Planner or Planning Coordinator as specified in Requirement R1. This includes many requirements such as reliability impact, adherence to planning criteria and interconnection requirements, conducting power flow studies, alternatives considered and coordinated recommendations.

II. ASSET HEALTH

A. Overview

The NSPM electric distribution system is composed of nearly 27,000 miles of distribution lines and 1,200 feeders that provide the path for delivering electricity from the distribution substation to the distribution customer transformer and then to customers. Maintaining and improving this vast system is key to ensuring customers receive safe, reliable and cost-effective energy. It is critical that we continually invest in our aging infrastructure through established reliability and asset health programs to ensure that we deliver the reliable and efficient energy, while providing a good customer experience. The utility industry is changing rapidly and customer expectations for power availability are also changing. To meet or exceed these expectations and maintain a reliable system we will need to continue to improve our system and asset health

As discussed in detail in the multi-year rate case we are submitting concurrent with this IDP on October 25, 2021, Asset Health and Reliability are Distribution's largest capital budget category, as these investments are essential to ensuring that our distribution remains safe and reliable. These budget categories include new and ongoing projects that we perform each year to address the age and condition of our distribution facilities. We plan to add a number of new Asset Health and Reliability programs to address specific assets that are, in some cases, having a pronounced impact on reliability. These new programs include the following:

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

To determine the facilities that need replacement or repair each year, we continually monitor, analyze, and address challenges within the system. We monitor the health of our distribution assets and track for example, the fleet age of each of our major distribution assets. That age can be used as a determining factor on the health of those assets. We also analyze reliability data and work to address those components that have poor reliability performance.

Our investments in Asset Health and Reliability fall into two larger categories – routine projects and larger discrete 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, poles, and substation equipment which have reached the end of their life. This category also captures replacements due to storms and public damage. In addition to these routine projects that we perform each year, Distribution also undertakes non-routine discrete projects that relate to asset renewal (addressing aging infrastructure with specific conversion or upgrade projects) or reliability (where the age of facilities impacts failures, reliability, and customer outages). In this section, we provide examples of these programs and investments.

B. Underground Distribution Assets and Reliability

For underground distribution assets, reliability performance is heavily influenced by the performance of mainline and tap cable. We analyze cable failure rates for both types of cable, and budgets to manage the reliability. Analysis has shown that the era of the cable is a primary indicator of its failure rate, which allows us to focus efforts on the cable most likely to fail. Historical performance of cable has also influenced our standards for future purchases for new construction and replacement work. We work using current and historical data to target cable replacements to improve the overall customer experience balanced with other Distribution priorities.

C. Overhead Distribution Assets and Reliability

The overhead distribution reliability performance is dependent on many factors including vegetation, weather, and the health of the many pieces of the overhead system.

1. Vegetation Program

The vegetation program is a key program to maintaining good reliability. The vegetation program includes quality checks by visiting outage locations associated with vegetation that impacted 100 or more customers. The check determines if the outage would have occurred if a vegetation crew had worked the line the day before. These checks are showing the value of our vegetation program in mitigating outages. Unfortunately, vegetation events can cause damage to our asset health, especially to older assets, so minimizing events is a key factor in maintaining asset health.

2. New Arrestor Replacement Program

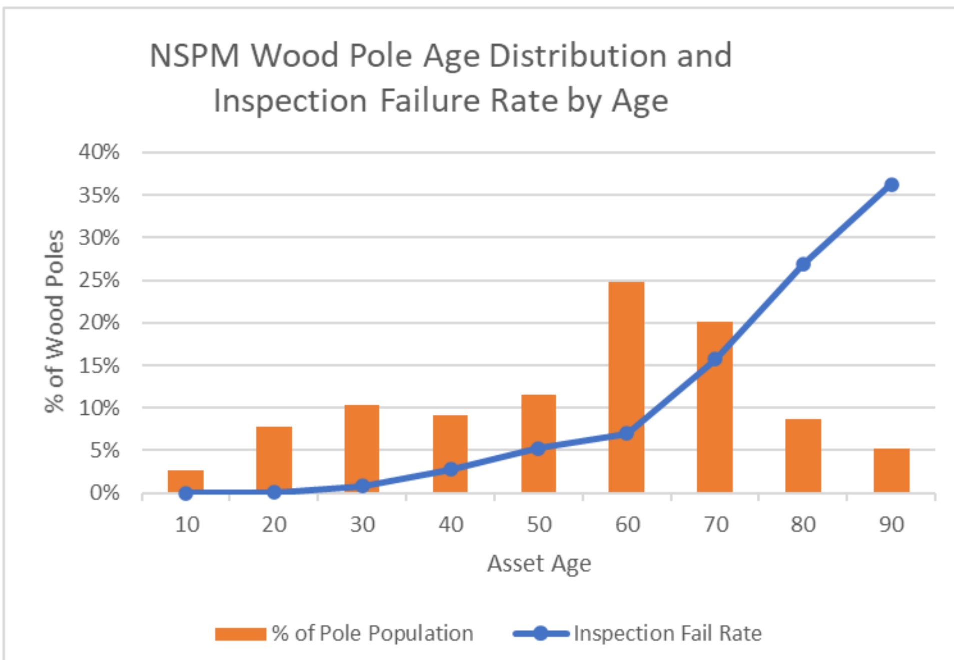
Our new arrestor replacement program will replace arrestors on our overhead feeder lines that have higher than average failure rates. It is estimated that over 90 percent of the System Average Interruption Duration Index (SAIDI) impact from failed arrestors is from less than 30 percent of the arrestor population.

D. Pole Inspections and the Pole Top Reinforcement Program

Checking the health of our poles is an important element in asset health management. Wooden pole integrity decays with time and exposure to the elements and wildlife. Along with other utilities across the country, the Company has a significant number of poles that are 50 years old or older. This is due to the fact that there was large buildout of the distribution system in the 1950s and 1960s in response to the population growth and suburban expansion during this time. While these poles have performed well for the past 60-70 years, these poles are now reaching the end of their life. Given the advanced age of our poles, it is important that Distribution maintain a steady assessment and replacement schedule so that any issues with our poles can be identified and rectified prior to a pole failure.

Figure 1 below portrays wood pole inspection failure rates by their age. Poles with less than the required remaining strength are replaced or reinforced. Pole rot at the base of the pole can be a cause of pole failure, especially in stormy weather. We work to inspect poles on a 12-year cycle to mitigate risk of pole failures.

Figure 1: NSPM Wood Pole Inspection Failures by Age



In addition to pole replacements, we are initiating a pole top reinforcement program to help identify poles and attached components that may require repair or replacement. This is a new program that will identify and replace pole top equipment and poles that have reached the end of their useful life. Pole top equipment includes cross-arms, braces, and insulators. Pole top issues include degraded cross-arms, degraded pole tops, loose guy wires, and cracked cutouts. With this advanced age, many of these pole tops, like the poles themselves, are in poor condition. Pole top equipment that is poor condition is a major contributor to outages and storm related interruptions. Replacing this damaged equipment will harden the system and improve system performance especially during high wind conditions, icing, and heavy snow.

The pole top program may begin as early as 2022. Pole tops will be photographed using drones and assessed by qualified personnel. An aerial vantage point provides clear views of instances of damage and decay that can be difficult to identify from ground level. A photo sample from a pilot drone program is provided below.

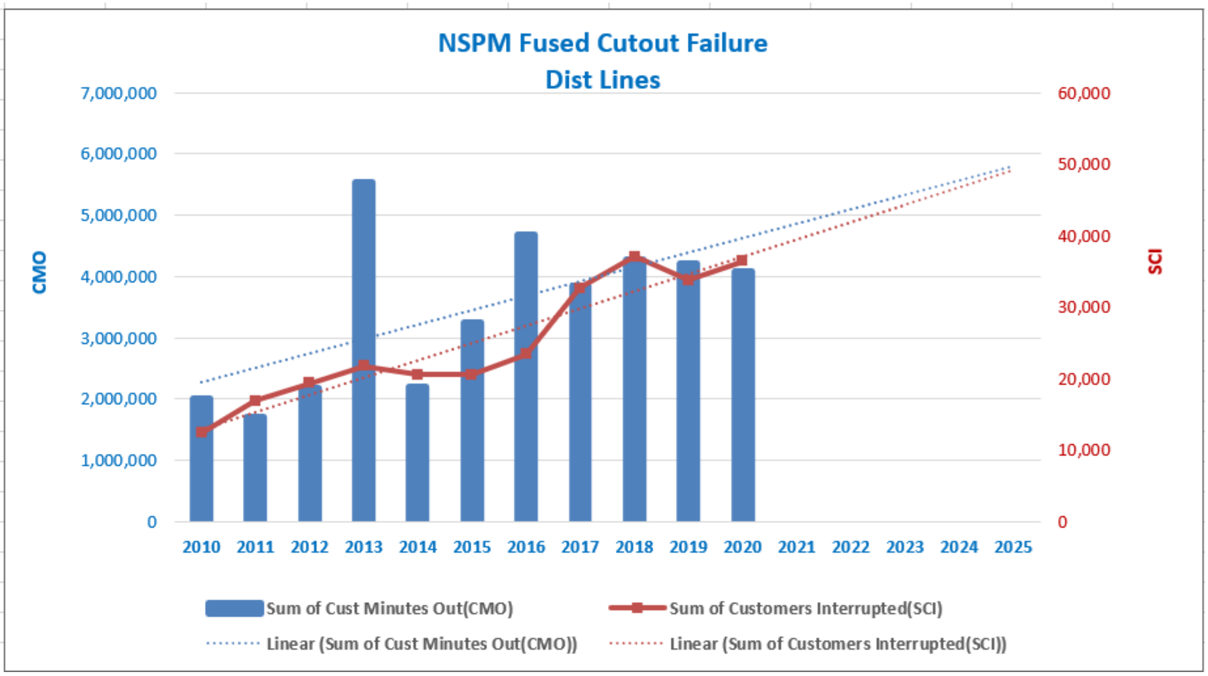
Figure 2: Example Drone Photo– Wood Pole with Decayed Top

E. Porcelain Cutout Replacement Program

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

We along with many other utilities switched to installing polymer cutouts in 2010 for new feeder installations. As compared to porcelain, polymer cutouts have better cold weather reliability, are more durable during transit and installation, and have superior mechanical toughness. However, the Company still has over 100,000 porcelain cutouts on its system and these porcelain cutouts have been experiencing an increasing rate of premature failures in recent years, averaging approximately 750 failures each year. The Figure below shows the total impact that these failed cutouts have on Customer Minutes Out (CMO) per year and on the number of customers interrupted each year. This Figure also shows the projected trajectory of failures if the cutouts are not addressed.

Figure 3: NSPM Fused Cutout Failures 2010-2020



F. Other Programs and Initiatives

Another area we expect to make greater investments in the near-term is in our Substation Renewal programs, to move toward replacing these assets closer to the end of their useful life. This program is focused on improving the reliability and resiliency of the Company's substations in Minnesota through the replacement of key substation components. One of the main substation components is transformers. Substation transformers are fundamental to the reliability of our distribution system and are also one of the most expensive components of the substation. While the failure of transformers is not a common occurrence, when a substation transformer fails, the consequences are high as it often results in between 5,000 to 15,000 customers losing service. There are a number of transformers on our system that are beyond their expected useful life of 55 years and we risk a greater number of transformer failures, and resulting outages for customers, if these assets are not replaced in a timely manner. In addition to transformers, there are several other important components to a substation such as switches, breakers, relays, fences, and regulators that also must be maintained in working order. This program also includes investments to replace our mobile transformers that have reached the end of their life. Our mobile transformers are an essential asset that enables the Company to quickly restore power to customers when a substation transformer fails and a new permanent transformer must be installed (a process that can take several weeks).

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

III. RELIABILITY MANAGEMENT

Each year, Xcel Energy develops and manages programs to maintain and improve the performance of its transmission and distribution assets. We identify and implement these programs in an effort to assure reliability, enable proactive management of the system as a whole, and effectively respond when outages occur.

We discuss our reliability indices, results, and programs in much more detail in our both of our annual service quality filings as required under our tariff as well as the Minnesota Rules.[1] However, we provide a brief summary here of relevant sections from those reliability reports.

[1] QSP Tariff filing provided annually in Docket No. E,G002/CI-02-2034 and QSP Rules filing provided annually in a new docket each year, the most recent being Docket No. E002/M-21-237

A. Reliability Indices

In this section, we provide a snapshot of our 2020 reliability results. We additionally outline our process for developing and implementing programs to maintain and improve our system and detail key indicators of the highest impact programs. We have also included a discussion around CEMI (Customers Experiencing Multiple Interruptions) tools to better reflect the customer experience.

In 2020, we achieved a SAIDI result of 95.52 minutes, which exceeds our Quality of Service Plan tariff goal of 133.23 minutes.[2] Our 2020 SAIFI result of 0.96 outage events also exceeds the QSP tariff goal of 1.21 outage events.[3]

In an effort to provide the Commission a better idea of our reliability performance trending, we have provided three tables showing the historical performance, storm days and the current targets under three methodologies (including storms, our QSP Tariff, and the Minnesota Rules). These three tables are presented below as Table 2.

[2] Minnesota Electric Rate Book MPUC. No. 2 Section 6, Sheets 7.1 through 7.11, approved by the Commission's August 12, 2013 Order in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383
[3] In this context, "exceeding" the goals is a positive result, reflecting good system performance.

Table 2:

Historical Reliability Indices & Storm Day Exclusions

All Days[1]		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Minnesota	SAIDI	207.77	149.15	562.11	116.43	184.50	214.39	141.70	125.00	124.50	134.19
	SAIFI	1.11	1.07	1.39	0.92	0.96	1.05	0.90	0.95	0.86	1.07
	CAIDI	187.11	139.51	404.36	126.00	192.32	204.84	158.10	131.22	145.30	124.89
Metro East	SAIDI	113.90	190.95	352.30	123.54	177.19	223.67	136.51	112.11	104.57	124.02
	SAIFI	0.96	1.20	1.27	0.98	1.04	1.08	0.95	0.96	0.85	1.07
	CAIDI	118.95	159.23	278.46	125.93	169.86	206.85	144.37	116.71	122.52	115.72
Metro West	SAIDI	238.03	139.19	810.01	105.98	229.78	198.25	148.58	88.23	79.92	143.84
	SAIFI	1.19	1.10	1.55	0.89	1.00	1.00	0.86	0.92	0.74	1.13
	CAIDI	199.66	126.85	523.66	118.70	229.92	198.86	173.27	95.70	107.38	127.72
Northwest[4]	SAIDI	470.05	109.75	468.22	82.82	75.61	225.74	173.71	109.50	150.82	133.55
	SAIFI	1.40	0.87	1.40	0.82	0.66	1.07	0.98	0.87	0.94	0.98
	CAIDI	334.78	126.17	335.53	101.00	115.40	211.50	177.46	126.02	160.71	135.77
Southeast[5]	SAIDI	125.28	97.25	179.29	173.45	98.23	249.05	96.37	353.32	374.19	122.43
	SAIFI	0.95	0.71	1.06	0.98	0.79	1.15	0.84	1.15	1.32	0.92
	CAIDI	131.69	137.84	168.93	176.51	125.07	217.15	114.75	307.95	283.40	132.38

MN Tariff[2]		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	'20 Target
Minnesota	SAIDI	83.87	96.20	91.12	79.85	86.83	89.49	73.80	93.26	76.66	95.52	133.23
	SAIFI	0.82	0.88	0.86	0.78	0.79	0.81	0.72	0.85	0.70	0.96	1.21
	CAIDI	102.08	109.60	106.51	102.07	109.90	110.54	102.10	109.90	109.74	99.73	NA
Metro East	SAIDI	79.34	90.70	83.56	77.58	93.71	95.49	75.70	103.28	79.26	104.56	
	SAIFI	0.83	0.88	0.83	0.82	0.90	0.87	0.75	0.92	0.72	0.99	
	CAIDI	96.00	103.35	100.72	94.81	104.58	110.07	100.79	112.40	110.29	105.19	
		2	5	3	3	2	3	3	1	2	1	
	MED's	7/1, 7/10	6/10,6/19,7/3, 8/3,11/10	6/21, 6/22, 6/23	2/20, 6/14, 6/16	7/12, 7/18	7/5, 7/6, 7/21	6/11, 6/14, 7/12	5/24	7/15, 9/2	8/14	
Metro West	SAIDI	88.20	103.42	101.24	81.85	88.98	82.90	69.28	81.25	68.25	87.46	
	SAIFI	0.87	0.97	0.96	0.82	0.82	0.82	0.70	0.84	0.69	1.01	
	CAIDI	101.09	106.83	105.85	100.15	108.90	101.51	98.40	96.63	99.17	86.19	
		5	3	5	1	1	3	2	1	2	4	
	MED's	5/22, 7/1, 7/10, 7/18,8/1	2/29, 6/19, 8/3	6/21,6/22, 6/23,6/24,8/6	6/14	7/18	7/5, 7/6, 7/21	6/11, 6/14	7/1	7/14, 7/15	5/29, 7/18, 8/10, 8/14	
Northwest[4]	SAIDI	79.42	94.20	85.78	62.16	69.39	80.19	69.41	99.87	61.17	100.31	
	SAIFI	0.69	0.73	0.75	0.61	0.57	0.56	0.64	0.73	0.53	0.75	
	CAIDI	115.38	128.31	113.87	102.05	121.05	143.58	107.70	137.06	115.94	133.14	
		6	0	2	0	0	4	1	0	5	3	
	MED's	2/20,5/30,7/1, 7/10,8/1,8/2	None	6/21, 6/22	None	None	5/19, 6/19, 7/5, 11/18	6/11	None	4/7, 4/11, 9/2, 9/17, 12/7	3/22, 7/18, 8/23	
Southeast[5]	SAIDI	82.70	82.40	73.58	94.45	70.78	109.59	92.84	110.67	122.21	99.53	
	SAIFI	0.70	0.59	0.57	0.67	0.52	0.82	0.79	0.77	0.84	0.76	
	CAIDI	118.72	138.48	129.93	141.93	135.23	133.06	117.19	144.04	145.17	130.46	
		2	1	4	4	1	3	0	2	4	1	
	MED's	7/1, 7/23	8/4	4/9, 5/2, 5/26, 6/21	2/20, 6/16, 8/4, 12/15	7/18	6/10, 7/5, 7/6	None	4/14, 9/20	4/10, 4/11, 7/20, 9/24	8/8	

Annual Rules[3]		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	'20 Target
Minnesota	SAIDI	88.17	101.86	94.27	84.00	89.95	90.45	75.04	96.07	81.02	98.92	NA
	SAIFI	0.88	0.93	0.90	0.84	0.83	0.83	0.74	0.89	0.75	0.99	NA
	CAIDI	100.53	109.78	104.60	99.67	108.09	108.93	100.90	107.39	108.29	100.28	NA
Metro East	SAIDI	79.89	105.74	85.05	79.73	93.73	95.52	76.22	103.69	80.56	104.98	89.95
	SAIFI	0.85	0.96	0.86	0.86	0.90	0.87	0.76	0.93	0.75	1.01	0.84
	CAIDI	93.83	110.03	99.33	92.46	104.25	109.70	100.48	111.74	107.36	103.69	106.91
		2	3	3	3	2	3	3	1	2	1	
	MED's	7/1, 7/10	6/10, 6/19, 11/10	6/21, 6/22, 6/23	2/20, 6/14, 6/16	7/12, 7/18	7/5, 7/6, 7/21	6/11, 6/14, 7/12	5/24	7/15, 9/2	8/14	
Metro West	SAIDI	89.74	103.98	101.41	83.02	90.95	83.64	69.51	83.26	69.50	88.82	79.37
	SAIFI	0.90	0.98	0.96	0.84	0.84	0.82	0.71	0.87	0.70	1.00	0.79
	CAIDI	99.56	105.93	105.45	98.50	108.44	101.43	97.84	95.47	99.15	88.53	100.55
		5	3	5	1	1	3	2	1	2	4	
	MED's	5/22, 7/1, 7/10, 7/18, 8/1	2/29, 6/19, 8/3	6/21, 6/22, 6/23, 6/24, 8/6	6/14	7/18	7/5, 7/6, 7/21	6/11, 6/14	7/1	7/14, 7/15	7/18, 8/10, 8/14, 10/20	
Northwest[4]	SAIDI	94.29	95.05	97.43	82.80	75.58	85.81	75.77	109.34	89.07	121.94	87.11
	SAIFI	0.82	0.83	0.94	0.82	0.66	0.70	0.76	0.87	0.78	0.93	0.75
	CAIDI	115.31	115.16	103.70	101.02	115.39	122.38	100.28	126.05	113.48	130.98	115.72
		6	1	2	0	0	5	1	0	3	1	
	MED's	2/20,5/30,7/1, 7/10,8/1,8/2	6/17	6/21, 6/22	None	None	5/19,6/19,7/5, 7/16, 11/18	6/11	None	1/26, 4/11, 9/2	7/18	
Southeast[5]	SAIDI	101.86	85.95	87.98	103.45	86.51	110.23	96.33	118.80	129.10	105.07	94.82
	SAIFI	0.90	0.67	0.73	0.80	0.75	0.85	0.84	0.92	0.93	0.87	0.76
	CAIDI	112.82	128.50	120.39	129.20	115.16	130.02	114.73	129.64	138.99	120.29	122.04
		1	1	4	4	1	3	0	2	4	1	
	MED's	7/1	8/4	4/9, 5/2, 5/26, 6/21	2/20, 6/16, 8/4, 12/15	7/18	6/10, 7/5, 7/6	None	4/14, 9/20	4/10, 4/11, 7/20, 9/24	8/8	

1) **All Days** - Includes All Days, Levels and Causes, Meter-based customer counts
2) **MN Tariff** - Normalized using IEEE 1366 at the Regional level after removing Transmission Line level. All Causes, Meter-based customer counts
3) **Annual Rules** - Normalized using IEEE 1366 at the Regional level, All Levels, All Causes, Meter-based customer counts
4) **Northwest** - Includes customers counts and interruptions in the North Dakota work region that impact Minnesota customers
5) **Southeast** - Includes customers counts and interruptions in the South Dakota work region that impact Minnesota customers

Xcel Energy developed tools that allow us to better track the causes of our CEMI (Customers Experiencing Multiple Interruptions). In conjunction with a mapping tool we can look at our customers' experience as it identifies customers with multiple outages over a revolving 12 months and then provide a visual representation of those outages in our service territory. Although, the metric measures customers who have experienced at least six sustained outages during non-storm days, we can study customers' experience earlier. This customer centric tool helps highlight customers that have had outages from different causes rather than a single root cause. In other words, this tool does not look at the device that caused the outage, it examines how many times a customer was out of service regardless of the reason.

These tools compliment other programs, such as the Outage Exception Reporting Tool (OERT) that help us identify specific equipment issues (for instance, the same device tripping multiple times). The CEMI tools provide the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this tool really rounds out our reliability planning by helping focus on the customers' experience.

There are many reasons a customer could have an outage. These causes include downed trees, animal contact, a car hitting a pole, or even a lightning strike. Each one of these causes could show up on a different report for a different piece of equipment that all flow down to the same customer. These tools allow us to analyze customer experience truly from a customers' experience. These tools help our efforts in the long term to reduce repeated outages for customers.

B. Reliability Management Programs

Causes and trends for historical outages are monitored and reviewed to identify opportunities to maintain and improve reliability. Investments in reliability improvement are made in addition to other capital programs that provide for adequate capacity to meet customer requirements. Investments for improvement become part of the reliability management program. A reliability core team, consisting of both field and planning functions, monitors system performance and progress against performance targets on a regular basis, taking actions as necessary to ensure the best possible system performance.

1. Reliability Management Programs – Key Initiatives

After considering the most common failures and their causes, as well as at-risk equipment, we have developed work plans, or programs, to target our investments; we show a summary of these programs in the 'Star Chart' on the following page. These programs represent those proactive investments in our transmission and distribution systems that we believe are most likely to improve overall reliability, asset health, and meet various contingency planning requirements. These investments are made in addition to other capital investments that provide for adequate capacity to meet customer requirements and to accommodate load switching during outage response to minimize customer impacts.

Table 3: Reliability Management Program Impacts (Star Chart)

NSPM Program Summary

	Funded Programs	Description	2018 Actuals (k$)	2019 Actuals (k$)	2020 Actuals (k$)	IMPACTS			
						SAIFI	CAIDI	CEMI	Complaints
Reliability	**Feeder Perf. Improvement Program** (OH & UG)	FPIP evaluates and implements improvements for feeders experiencing an increased number of outages based on prior year information.	1,451	1,138	1,011	★		★	★
Reliability	**Outage Exception Reporting Tool** (OH & UG)	OERT process provides automatic notification to area engineers when repeating outage criteria have been met and engineering solutions are implemented to eliminate recurring problems.	490	292	143			★	★
Reliability	**Mainline Cable Replacement,** (UG)	Deteriorating non-jacketed cable is failing and causing repeat outages. Proactive and reactive replacement of this cable reduces the outages.	1,930	2,557	1,719	★			★
Reliability	**Tap (URD) Cable,** (UG)		19,593	15,019	26,470	★	★		★
Reliability	**Install Automated Switches**	These automation solutions reduce restoration times for long lines with long drive times to bring CAIDI in-line with other distribution lines.	0	0	65	★		★	★
Reliability	**Feeder Infrared Evaluation** (OH)	Many pieces of equipment show excess heating prior to failure. The FIRE program provides infrared scans of overhead mainline which reveal specific equipment that is likely to fail so it can repaired prior to causing an outage.	58	40	40	★			
Reliability	**Vegetation Management** (Transmission & Distribution)	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.	29,352	31,193	20,633	★		★	★
Reliability	**Program Replacements** (Transmission)	Replaces end-of-life equipment (i.e. - switches, laminated arms, specific insulators, poles) in order to reduce maintenance costs and improve reliability.	229	1,444	3,764	★			★
Integrity	**Pole Inspection & Replacement** (Distribution)	Pole Inspections include an above groundline visual inspection. Groundline inspections are based on age and environment and may include visual, sound and bore and excavation. Treatment of poles may be included. Based on results poles may be tagged for replacement.	11,035	20,500	28,285	★	★		
Integrity	**Transmission Substation**	Replaces end-of-life equipment in order to reduce maintenance costs and improve reliability.	9,228	5,759	2,863	★			
Integrity	**Line ELR Work** (Transmission)	Identifies lines that have components that have reached their end of life or where significant refurbishment work is needed to enhance system performance and reliability. Project focus may be to extend life of existing asset 20 + years or to replace and address future capacity upgrade concerns.	2,834	5,303	2,239	★			★

Footnote: The above table reflects multi-year initiatives that are part of the Reliability Management Program(RMP). Information is based on current RMP, and is subject to change.

Funding information for previous years is a combination of Capital and O&M dollars; most of the equipment replacement dollars are capital expense while the inspection and testing programs include O&M dollars; O&M dollars and capital for pole replacements and FIRE program are currently estimates since changes are included in broader programs of work(e.g., OH rebuild OH maintenance accounts).

We have indicated the primary performance impacts of these programs with a red star, where applicable; performance impacts include SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration

Index), CEMI (Customers Experiencing Multiple Interruptions) and Customer Complaints.

The table below outlines primary program indicators for our key initiatives/programs. The actual amount of work completed under each program varies from year to year and is based primarily on assessments of those areas requiring the greatest attention, as well as the results of our condition assessment (i.e., the number of deficiencies requiring corrective action). For further description of the programs described in Table 4 below, Key Initiatives, please see the Star Chart (Table 3 above).

Table 4: Reliability Management Key Initiatives

	2020	2019	2018	2017	2016	2015	2014
Outage Exception Reporting Tool (OERT) (Replaced REMS in 2016)							
# of Exceptions identified	3,927	3,735	4,014	3,398	6,635	4,935	5,105
# of Service & Work Requests identified	959	518	652	297	215	408	455
Vegetation Management Program							
Total Overhead Distribution miles completed	1,606	2,647	2,307	2,417	2,086	1,856	3,737
Total Overhead Transmission miles completed	762	896	768	762	1,039	909	879
Normalized Tree-coded Sustained Cust Ints.(W/O Storms)	184,302	170,994	214,299	145,422	155,370	106,215	93,010
Non-normalized Tree-coded Sustained Cust Ints.(With Storms)	286,735	242,158	243,867	277,068	305,946	220,787	154,642
Underground Cable Replacement Program							
# of Segments That Have Been Replaced (est.)	2,579	1,158	1,504	1,411	1,378	861	1,165
# of Failures(Only on Primary Cable)	1,459	1,301	1,366	1,453	1,607	1,560	1,386
Feeder Infrared Evaluation(FIRE)							
# of Feeders Scanned	259	280	209	248	275	256	267
# of Hot Spots Corrected	66	55	67	71	68	99	62
Feeder Performance Improvement Plans(FPIP)							
Investigations Completed	112	111	108	113	105	96	108
Wood Pole Inspection Plan							
Total Distribution Wood Poles Inspected	40,179	10,312	33,720	17,972	18,845	10,213	9,198
Total Transmission Wood Poles Inspected	3,124	3,381	2,464	4,000	4,660	4,119	3,565

Information based on current RMP, subject to change

2. *Reliability Management Programs – Work Practices*

Improvements to existing work practices that the reliability core team members and their staffs identify, and implement are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur, or to reduce the *frequency* of outages.

As noted in the Reliability Management Work Practices table below, we assess and prioritize the actions based on a balance of their ability to positively impact reliability (high, medium or low), as well our ability to incorporate into standard work practices – with most occurring concurrently. Many of these actions do not require additional funding to implement and are achieved via ongoing employee training and/or incorporation into standard work procedures. We continuously monitor all actions and update our plan as appropriate.

Table 5: Reliability Management Work Practices

Areas of Opportunity	Key Initiative	Action/ Program	Description	Reliability Impact
Resource Management	Duration	Work Coordination	Adding a full-time work coordinator to schedule all appointment work. The coordinator will be in contact with customers prior-to, during and following their scheduled appointment. This will optimize use resources in support our customers. Better customer service for appointments and resource availability for outage restoration work will result.	Medium
	Duration	Management Staffing	Schedule managers for staggered shifts in metro area to enable human response after hours: 3 managers working 5:30 a. m. to 4:00 p.m.: 1 manager 3:00 p.m. to 11pm.	Medium
	Frequency	System Integrity	Substation inspection done on every substation specific to identifying animal incursion risk and vegetation issues.	High
Substations	Frequency	Infrared Inspections	IR Subs after major equipment is switched out of service or thermal heating is suspected.	High
	Duration	Equipment Failure Response	Install Mobile subs and connection cables as quickly as possible when customers are out due to equipment failure.	Medium
	Duration	Restore before repair	During a feeder event Control Center personnel restore service to as many customers as possible before making temporary/permanent repairs.	Medium
	Duration	Patrol Optimization	Use of application software to assist manual patrol of outages and momentary outages. This will allow for quicker response and permit a single resource to respond to a greater number of outages or appointments.	Medium
Feeders	Frequency	Intentional Outages	Reduce impact of intentional outage to ensure all steps are being taken to keep the maximum number of customers on. Verify switching to reduce customer counts. Repair while hot instead of taking outage.	Medium
	Frequency & Duration	VM Partnership	Partner with Vegetation Management leadership to prioritize trimming of circuits that are scheduled to be trimmed. Substations to be trimmed with associated feeders.	High
	Frequency & Duration	Feeder Patrol Program	Looking for unfused taps and animal protection. Identify 336 auto splices. Continued use of IR/thermo imaging to identify problems.	Medium
	Frequency	Condition Assessment & Correction	Utilizing UAS (Drone) technology to complete a comprehensive inspection of our worst performing feeders, a pilot program has been instituted to identify and mitigate risk to the distribution system.	High
	Duration	Restore before repair	Advanced technology going into the control centers and the field.	High
Control Center	Duration	Distribution Operations Model	DMS (Distribution Management System) currently scheduled to be installed by year-end 2021. This will allow detailed visibility into the distribution system.	High
	CAIDI	Model 1/0 Switching	This is a pilot project to model 1/0 URD as close to real time so the OMS model will reflect the configuration of the URD circuit after it has been switched.	Medium
	CAIDI	Validate Restoration Times	Tighten up existing process on actual restoration times, utilize approver process to ensure outage times are correct.	High
	CAIDI	COM Saturday Crews	metro COM Saturday Crews. 3 Metro East and 3 Metro West	Medium
COM	CAIDI	Backup Crews	Currently negotiating on-call crews for outage response, Friday-Monday to enhance response time to customer outages.	Medium
	SAIFI & CAIDI	Underground Cable Repair	Repair and/or replace cables as directed by engineering	High
	SAIFI	REMS/CEMI Work	Complete work referred by engineering in a timely manner	Low
	SAIFI & CAIDI	On-going Regular Reliability Meeting	Meet regularly to review reliability and share ideas to improve reliability performance.	Low
Reliability Team/ Communications	CAIDI	Outage Reviews	Root Cause Investigation of outages greater than 90 minutes or 0.1 SAIDI	Medium
	CAIDI	Continuous Improvement	6. In 2021, Control Center Leadership is producing a detailed CAIDI report on a monthly basis, the purpose and impact of the report is to call out opportunities for improvement on response, meet with the first responders to develop plans to remove obstacles to response and holding employees accountable to timeliness of response using the data and operator comments.	Medium

APPENDIX A3: DISTRIBUTION OPERATIONS

In this section, we discuss key aspects of our distribution operations. First, we discuss escalated operations – or how we plan for, approach, and respond to unplanned events impacting our system and customers – most frequently these are storm or weather-related. Part B of this section discusses other major components of our day-to-day work to provide our customers with reliable electric service. These activities include Vegetation Management, Damage Prevention, and Fleet and Equipment Management.

I. REACTIVE TROUBLE AND ESCALATED OPERATIONS

We have discussed the many ways that we plan the system to ensure reliable service for our customers. However, sometimes we must quickly rally and respond to customer outages and infrastructure damage caused by outside forces, such as severe weather. In this section, we discuss our pre-event planning, outage restoration, and outline storm-related costs.

A. Escalated Operations Pre-Planning

To ensure we are prepared, we maintain a Distribution Incident Response Plan that guides our planning, execution, and communications – and we regularly assess and drill our readiness and response. Our planning and preparations start well in advance of an actual weather event with foundational elements such as agreements with contractors to supplement our field forces when needed – and mutual aid agreements with other utilities for the same purpose. One indicator of our preparedness and response is measured by the increase in storm events that do not meet Major Event Day exclusions. Due to detailed response plans, drills and pre-staging of crews we are able to complete restoration sooner for our customers, past process was to react after the storm past, this allowed for exclusions of customer minutes out and improved SAIDI, yet this doesn't provide the best customer experience.

We also maintain lists of hotel accommodations and conference facilities across our service area for when they are needed to house crews aiding in restoration activities, or serve as dispatch centers or areas to conduct tailgate or safety briefings. We also maintain lists of available transportation options such as for buses and vans, to move crews and support staff between locations. Finally, we also pre-identify staging sites across our service area so we are able to quickly implement plans that involve staging equipment or non-local crews, we have over 100 staging sites identified inside of our customer footprint – and ensure we have street and feeder maps readily available for them to use. Our planning also incorporates details are not top-of-mind when thinking about what might be needed for an effective storm response – such as ensuring we have ready access to catering to feed crews, adequate restroom availability, laundry facilities, garbage and debris containers, and security.

In terms of planning and preparations in the immediate timeframe before a weather event, we are continuously assessing the weather, system status and customer call volumes to recognize "early warning signs." As the storm picture becomes more clear, we inform office staff, field workforces, and strategic communications stakeholders, which includes the call centers, external communications, community relations, and regulatory affairs, among others. We begin to send regular weather and staffing updates to pre-defined internal distribution lists, and inform employees in identified storm support roles to prepare for an extended time at work. At this point, we are also informing support functions such as supply chain, fleet, safety, security operations, and workforce relations of our assessment of the impending weather. We also inform our local unions of our assessment and planning criteria. We may also begin to strategically move and stage field crews and equipment to areas expected to be significantly impacted – especially if we expect access to those areas to be limited or hampered as a result of the weather event.

At the point operations leadership believes the forecast presents risk to the distribution system, we hold an operational call where we review our assessment of conditions, staffing, and other preparations. When system impact is confirmed, we initiate "Everbridge," which alerts pre-defined lists of individuals representing key functions across the organization.[1] A regular cadence of escalated operations calls that follow a standardized agenda and checklist that both communicates key facts about the event including customer and infrastructure impacts and restoration staffing – and gathers information from support functions and external facing groups such as from the call center, community relations, and large managed accounts.

As soon as Xcel Energy knows there is an outage, a crew is dispatched to investigate. When the crew arrives on the scene, it assesses the problem and proceeds with the repair. Due to the complexity of the Xcel Energy electric system and the variety of probable causes, this process can take several minutes or, in extreme circumstances, hours. Time estimates can vary based on the extent of the outage, public safety issues that take priority, etc. Upon completing a comprehensive assessment, the crews or

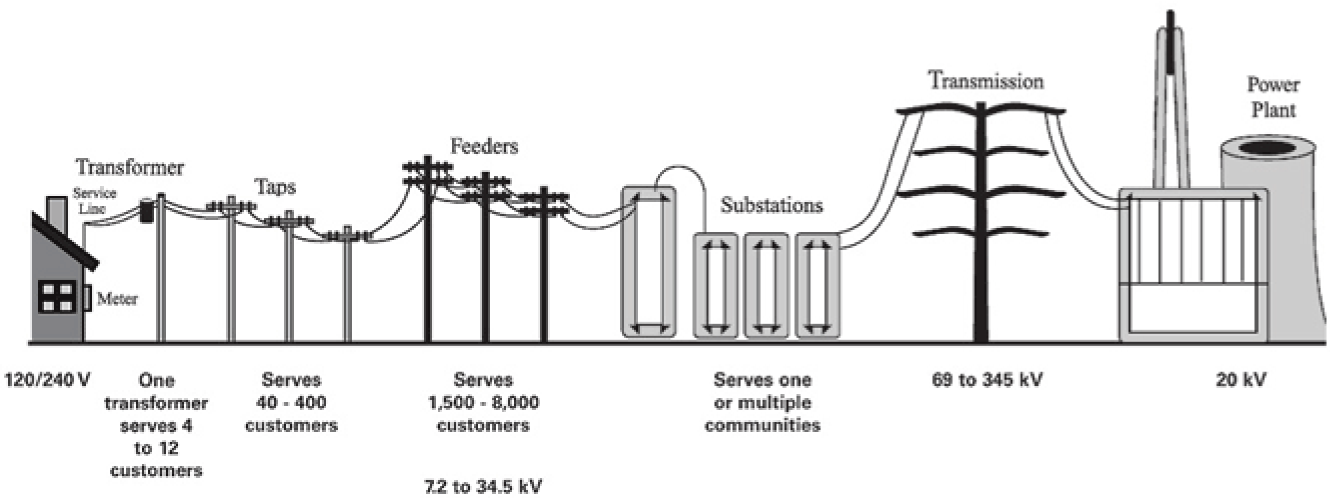
[1] Everbridge is a critical event management platform that helps organizations manage the full lifecycle of a critical event.

first responders update the estimated restoration time using mobile data terminals in their vehicle.

The Xcel Energy restoration process gives top priority to situations that threaten public safety, such as live, downed wires. Repairs are then prioritized based on what will restore power to the largest number of customers most quickly. Crews work around the clock until power is restored to all customers.

The number of customers affected by an outage will depend on where the cause of the outage occurred. Figure 1 below provides a high-level view of the major electric grid components involved in restoring power to customers, whether the outages are part of an escalated operations event or a more isolated outage event.

Figure 1: Major Grid Components



B. Outage Restoration

Outage restoration prioritization generally follows the system components that will restore power to the greatest numbers of customers, which we describe below. We note however, that we also take into consideration critical infrastructure such as schools, hospitals, and municipal pumping operations.

Restoration of transmission lines and substations are a top priority, because they may serve one or several communities. Generally, damaged or failed transmission facilities do not cause customer outages due to the interconnected nature of the transmission grid. Regardless, they are a top priority because a failed or damaged component reduces our resilience by creating a vulnerability on the grid. Transmission lines and substations have a dedicated workforce, which allows Distribution to focus on restoring portions of the system that more directly impact customers.

Substations can be either transmission or distribution. Distribution substations distribute power to feeders. One feeder might serve between 1,500 to 8,000 customers. Feeders distribute power to power lines called taps. One tap line might serve between 40 to 400 customers. Tap lines distribute power to transformers. Transformers may serve a single building or home, or serve multiple customers (generally 4 to 12 customers). Service wires connect transformers to individual residences and businesses.

Sometimes, a tap, feeder or substation outage will be restored while a transformer or an individual customer (service) may remain without power. This type of outage may go undetected at first until the customer notices that their neighbors have power, or they receive a notification that their electricity has been restored, when in fact, it has not been. AMI will significantly improve our ability to initially "sense" and thus record individual customer outages – and track them all the way through to restoration. Similarly, with this detailed information enabled by AMI, we will have increased capabilities to avoid "okay on arrival" truck rolls, because we will have better data at an individual customer level than we do today.

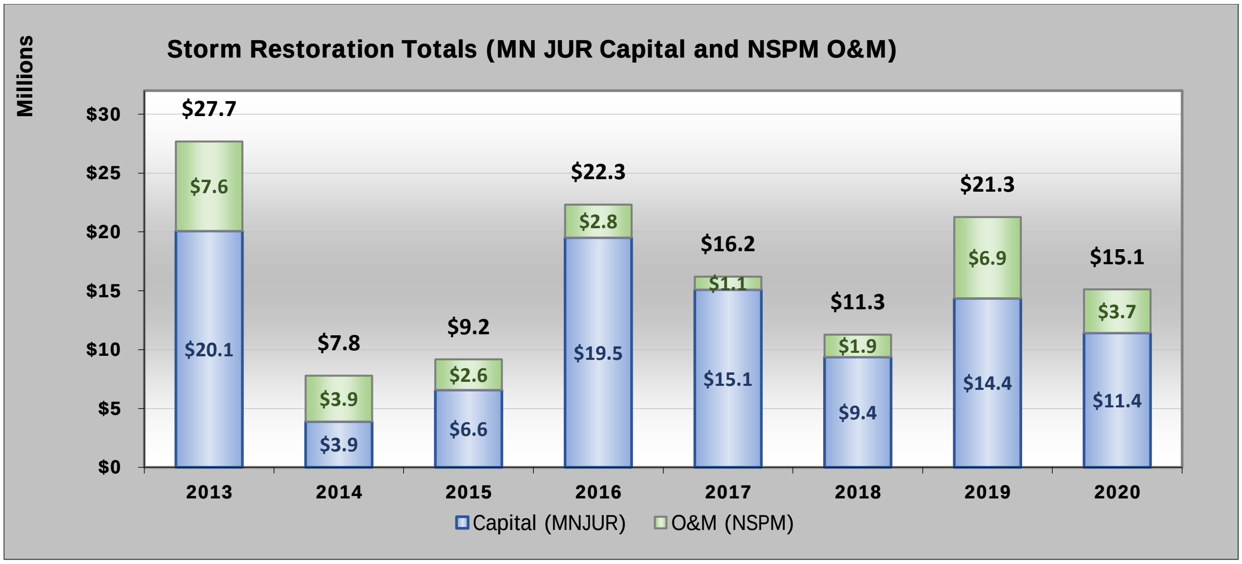
C. Costs Summary

Our annual capital and O&M expenditures are influenced by the magnitude and frequency of significant 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.

Figure 2 below portrays our capital- and O&M-related Escalated Operations costs for the recent past, demonstrating how variable this aspect of our operations can be.[2]

[2] Represents escalated operations events significant enough for a workorder to be established.

Figure 2: Escalated Operations – State of Minnesota Electric Capital and O&M Expenditures 2013 to 2020 (Millions)



In terms of budgeting for storm restoration, due its significant variability from year-to-year, we budget dollars in a working capital fund that are not assigned to a specific project or program. When emergent circumstances, such as storm restoration arise, we reallocate budgeted dollars to address the circumstance while remaining in balance with our annual budget. For O&M, we do something similar – we factor-in a base level of funding within key labor accounts, such as productive labor and overtime.

II. DISTRIBUTION OPERATIONS – FUNCTIONAL WORK VIEW

In this section, we highlight a few key aspects of the distribution function that contribute to providing customers with safe and reliable service – but that are not as prominent as storm response or constructing new feeders and substations. These include:

- Our *vegetation management* program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our *damage prevention* program that helps the public identify and avoid underground electric infrastructure, and
- The fleet, tools, and equipment that support everything the Distribution function does every day.

A. Vegetation Management

The Vegetation Management activity includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages. It includes the activity associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on and adjacent to the Company's rights-of-way to limit preventable vegetation-related interruptions. An effective Vegetation Management program is essential to providing reliable service to our customers. We have established a five-year routine maintenance cycle for our distribution facilities, generally meaning that vegetation around our electric facilities will be maintained every five years.

Tree-related incidents are among the top two causes for electrical outages on the Company's 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. This category also includes the pole inspection program, because we use the same workforce to perform both of these activities.

We budget 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. To maintain 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. In addition to line-miles, key cost drivers 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.

B. Damage Prevention/Locating

The Damage Prevention category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements. This program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. We summarize in Table 35 below the volume of requests for electric facilities locates over the recent past:

Table 1: NSPM Electric Locates Volumes (2016-2026)

2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Forecast	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
446,383	460,483	459,904	470,697	502,348	502,636	517,715	533,246	549,243	565,720	582,692

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.

C. Fleet and Equipment Management

From a functional perspective, this category represents costs associated with the 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, which includes the necessary replacement of vehicles and equipment that have reached their end of life. The O&M component of fleet is those expenditures necessary to maintain our existing fleet, which 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 compared to capital projects.

The largest cost driver for this category is for fleet vehicles. Our fleet managers maintain accurate records on vehicles and have performed analysis to determine the optimal investments to ensure a reliable, yet cost-effective fleet. Through our rigorous tracking of vehicle maintenance expenses, we are able to select vehicles to replace in order to achieve the lowest cost of ownership. We analyze which units have met their candidate age for replacement, quantitatively prioritize which assets will return the largest reduction in maintenance and repair as a proportion to their capital investment, qualitatively review condition assessments with the mechanics, and review work priorities and gather non-replacement fleet needs with users. The annual fleet budget can then be derived based on the proposed number of fleet replacements (by type of vehicle) coupled with the latest known pricing for each type and quantity of vehicle being proposed for replacement.

APPENDIX A4: DISTRIBUTION SYSTEM STATISTICS

In this Section, we provide a snapshot of distribution system statistics for the Company in compliance with various IDP requirements for distribution system statistics.

I. EXISTING SYSTEM VISIBILITY, MEASUREMENT, AND CONTROL CAPABILITIES

IDP requirement 3.A.2 requires the following:

> *Percentage of substations and feeders with monitoring and control capabilities, planned additions.*

IDP requirement 3.A.3 requires the following:

> *A summary of existing system visibility and measurement capabilities (feeder-level and time-interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual).*

These two requirements are intertwined with each other because they both pertain to system visibility. Therefore, we have combined the information required in Items 3.A.2 and 3.A.3 into Table 1 below.

Table 1: Feeder Load Monitoring – State of Minnesota

FLM Type	% of subs[1]	Measurement	Measurement Interval	Automated /Manual	Frequency of reads	Min/ Max	Daytime/ Nighttime
Full FLM	47%	3 phase Amps, MW, MVar, MVA, kV	Hourly	Auto	Continuous[2]	Yes- *Manual effort*	Both
Partial FLM	20%	Has some or most of the above data points, varies by location	Hourly	Auto	Continuous[2]	Yes- *Manual effort*	Both
No FLM	33%	Only manual reads available (provides 3 phase Amps)	Varies	Manual	Varies	No	Neither

Note: Approximately 90% of our customers are served by substations and feeders that have Full or Partial FLM.
[1] Percentages are based on a total of 240 substations in Minnesota.
[2] While there is continuous data flow to the operation center, only hourly data is maintained in the data warehouse.

Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. This includes control and data of our system, and we frequently refer to the data acquisition portion as Feeder Load Monitoring (FLM). A substation that has SCADA almost always contains both FLM and control. However, there may be substations where we do not have FLM, but we do have control.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels over an entire year as the inputs to our planning process. Ideally, this includes three phase Amps, MW, MVar, MVA, and Volts. However, not all of these data points are available for all locations. For internal tracking and reporting purposes, when all three-phase Amps, MW, MVar, and kV are included on all feeders and two of the following three for the substation transformers (MW, MVar, or MVA) then that counts as full FLM. If we are missing one or more data points at the substation, it will fall under partial FLM. If we have nothing, then it falls under no FLM. Our SCADA-enabled substations and feeders serve approximately 90 percent of our customers (*Note*: Most of our non-SCADA substations are in rural areas).

Our SCADA also collects enough information throughout the course of a year to determine daytime minimum load for all feeders equipped with this functionality, but it takes extra manual effort to derive a daytime minimum load (DML). As discussed in *Appendix A1: System Planning*, in 2019 we prioritized the tracking and updating of DML and have determined and updated historical DML for all of our feeders and substation transformers that have load monitoring.

For no FLM and some partial FLM substations, on approximately a monthly basis, field personnel collect data, including peak demands for feeders and transformers. Peak load values are recorded in the field and entered into a database that engineering accesses and uses for planning purposes. After the recordings are documented, field personnel reset the peak load register, so the following period's data can be accurately captured without influence from the previous period. Because this is a manual process, the data may have gaps or may not occur at precise monthly intervals.

We additionally note that we have control capabilities at 67 percent of our substations. Similar to customers served from substations and feeders with full- or partial-FLM, approximately 90 percent of our customers are served by substations and feeders that have control capabilities.

Given the importance of SCADA capabilities to reliability and load monitoring (for planning and due to increasing levels of DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at 3-5 substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA. However, as discussed in more detail in our MYRP rate case filed October 25, 2021, starting in 2022, our Feeder Load Monitoring Program aims to complete the rollout of SCADA at most of the remaining substations in Minnesota.

IDP Requirement 3.A.9 requires the following:

> *For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system.*

The NSP System peak in 2020 was 8,571 MW, which occurred at 5:00 p.m. on July 8, 2020. The Minnesota portion of this peak was 6,372 MW.

We have SCADA capabilities that enable the Company to measure the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system at substations serving approximately 90 percent of our Minnesota customers. We have thus calculated the 2020 peak coincident load at 5,493 MW for the Minnesota portions of the distribution system with sufficient SCADA capabilities.

We clarify that in order to provide this information we must manually pull the maximum hourly load for each SCADA-enabled substation for the date and time of the NSP System. Due to the manual effort to fulfill this requirement, it would be helpful to understand how stakeholders intend to use this information – as there may be other information we could provide that would require less manual effort to meet that need.

II. NUMBERS OF AMI CUSTOMER METERS AND AMI PLANS

IDP requirement 3.A.4 requires the following:

> *Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available.*

We installed a total of approx. 17,000 AMI meters for Minnesota TOU pilot customers starting mid October 2019 to late February 2020. We currently expect to begin rolling out AMI meters to all of our Minnesota customers in early 2022 and that all of our customers will have an AMI meter by the end of 2024.[1] We discuss the planned AMI functionality and our AMI plans in more detail in *Appendix B1: Grid Modernization* of this IDP.

III. ESTIMATED SYSTEM LOSSES

IDP requirement 3.A.8 requires the following:

Estimated distribution system annual loss percentage for the prior year.

The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system.

Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class' total peak is reached.

There are five categories or distribution subsystems where specific losses occur. Within these categories there may be load and no-load losses, as summarized in Table 2 below.

Table 2: Categories of Load and No-Load 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

For example, transformers have both load and no-load losses. Load losses are function of the transformer winding resistance and the load current through the transformer; sometimes these losses are called copper losses. Transformers and

[1] The global computer chip shortage has impacted our AMI meter provider Itron in terms of meeting their planned meter shipments in 2021 and early 2022. We are still assessing the potential impact, but at this time we believe the delay in the deployment start will be minimal.

electric meters have also no-load losses which are a function of voltage. Voltages in US power systems are relatively constant, so no-load losses are considered relatively constant. Sometimes no-load losses are called iron or excitation losses.

Losses are estimated using engineering calculations and load research class customer load profiles, because advanced technologies and equipment to specifically measure actual losses across the transmission and distribution systems have historically been cost-prohibitive to implement.

Advanced technologies have been implemented on the transmission system that makes actual calculations of transmission losses more of a practical reality within the next year or so. However, advancements like this at the distribution level have lagged transmission due to the nature of the distribution system, which requires the advanced technologies to be implemented on a much wider scale. As we discuss below, our investments in AMI, FAN, and grid sensing and controls technologies as part of our grid modernization efforts will further our capabilities to mature this analysis over time.

The engineering analysis underlying our calculated losses used Company equipment records to determine numbers and sizes of distribution system lines and transformers, and engineering models to calculate losses from average loadings based on metered sales data through various distribution system components. The average loading method calculates losses based on the ratio loading on each of the following system components to the maximum of the components:

- Distribution substation transformers
- Primary lines
- Primary to primary voltage
- Transformers
- Distribution line transformers
- Secondary distribution lines

From this analysis, we perform calculations monthly to update the loss percentages for each system level, and then apply those percentages to sales. The process to update the loss percentages is as follows:

1. Gather five years of monthly MWh energy and sales by state.

2. Calculate the difference of energy and sales for each of the months in the 5-year timeframe.
3. Calculate a MWh loss percentage from the original MWh energy values by month in the 5-year history.
4. Calculate a 5-year average by month, using the values derived in step 3.
5. At this point, calculate a 5-year annual average using the values from step 4.
6. The values from step 5 are then used to represent current losses in each given state.
7. The overall losses by state described in step 6 are then used to update losses at each voltage level the engineering loss study completed.

This process resulted in the 2021 loss percentages for the state of Minnesota, as provided in Table 3 below.

Table 3: 2021 System Loss Percentages – State of Minnesota

Minnesota	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bulk(UT)	0.9672	0.9667	0.9646	0.9649	0.9682	0.9700	0.9691	0.9691	0.9688	0.9677	0.9669	0.9667
Bulk(T)	0.9614	0.9610	0.9587	0.9593	0.9630	0.9648	0.9637	0.9638	0.9639	0.9626	0.9612	0.9610
Tran(UT)	0.9561	0.9557	0.9533	0.9543	0.9583	0.9598	0.9585	0.9588	0.9595	0.9581	0.9560	0.9556
Tran(T)	0.9544	0.9541	0.9517	0.9527	0.9570	0.9583	0.9570	0.9574	0.9581	0.9568	0.9544	0.9539
Subtran(UT)	0.9466	0.9464	0.9440	0.9453	0.9505	0.9514	0.9497	0.9507	0.9516	0.9506	0.9468	0.9461
Subtran(T)	0.9409	0.9407	0.9383	0.9396	0.9445	0.9451	0.9431	0.9443	0.9458	0.9449	0.9410	0.9403
Primary	0.9275	0.9286	0.9269	0.9279	0.9305	0.9266	0.9223	0.9256	0.9312	0.9324	0.9280	0.9269
Large secondary	0.9147	0.9153	0.9129	0.9137	0.9172	0.9135	0.9092	0.9126	0.9175	0.9180	0.9146	0.9140
Small Secondary	0.9060	0.9063	0.9037	0.9040	0.9052	0.8996	0.8944	0.8995	0.9054	0.9080	0.9054	0.9051

In the MYRP filed October 25, 2021 in Docket No. E002/GR-21-630, the Direct Testimony of Company witness Ms. Kelly A. Bloch discusses our method for measuring distribution line losses and what it would take to measure actual distribution losses on the distribution system, which we summarize below;[2] Company witness Mr. Ian R. Benson discusses transmission line losses.

In summary, 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

[2] This information is in compliance with the Commission's June 12, 2017 Order in our 2015 rate case in Docket No. E002/GR-15-826 and is related to the Company's Class Cost of Service Study.

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.

To obtain data at the customer level, AMI meters along with the FAN communication network would need to be installed throughout the system. To collect substation level data, we would need SCADA technology at each distribution substation. We currently have full SCADA capabilities at 47percent of our substations and partial capabilities at 20 percent (See Table 1 above for additional SCADA capabilities information). 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.

In addition to the customer and substation level data, the Company would also need to collect secondary system level 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 secondary 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.

IV. OTHER DISTRIBUTION STATISTICS

A. Total Distribution Substation Capacity in KVA

IDP Requirement 3.A.10 requires the following:

Total distribution substation capacity in kVA.

NSPM distribution substation capacity = 15,037,793 kVA or 15,038 MVA

NSPM – State of Minnesota distribution substation capacity = 13,369,194 kVA or 13,369 MVA

The total distribution substation capacity is reflective of substations that are active, functional, and owned by the Company as of July 1, 2021. We calculated this by summing each individual distribution transformer's nameplate power rating across our Minnesota service area.

B. Total Distribution Transformer Capacity in kVA

IDP Requirement 3.A.11 requires the following:

Total distribution transformer capacity in kVA.

Consistent with our past IDPs, we understand this requirement to be the total distribution substation transformer kVA. Given that understanding, please see our response to 3.A.10 above.

C. Total Miles of Overhead Distribution Wire

IDP Requirement 3.A.12 requires the following:

Total miles of overhead distribution wire.

As of September 2021, we approximated our overhead conductor at 14,951 circuit miles for the NSPM operating company.

D. Total Miles of Underground Distribution Wire

IDP Requirement 3.A.13 requires the following:

Total miles of underground distribution wire.

As of September 2021, we approximated our underground cable at 11,822 circuit miles for the NSPM operating company.

E. Total Number of Distribution Premises

IDP Requirement 3.A.14 requires the following:

Total number of distribution premises.

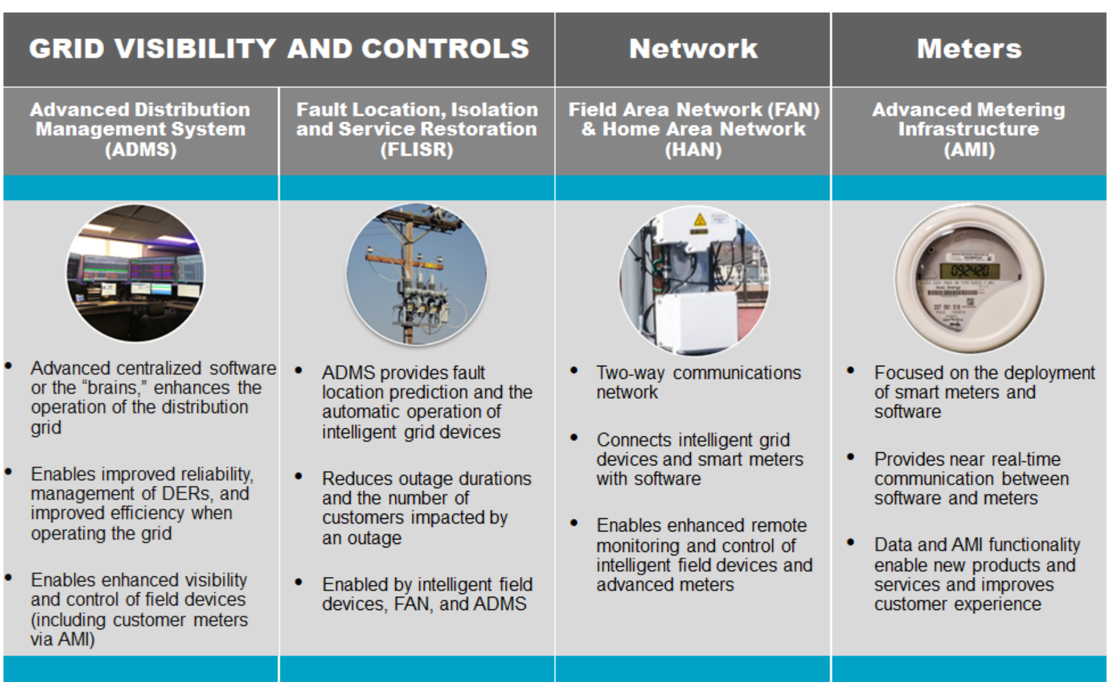
We clarify that a premise is a unique combination of meter number and address. As of the end of August 2021, we had 1,505,814 electric premises in the NSPM operating company, with 1,313,820 of those in our Minnesota service area specifically.

APPENDIX B1: GRID MODERNIZATION

For more than 100 years, Xcel Energy has provided its customers and communities with outstanding service – delivering safe, reliable, and affordable energy. We are looking to the future and advancing the grid to ensure it will continue to provide our customers benefits for many years to come. We are planning and investing in technologies to meet customer and operational needs now and in the future. We are taking a measured and thoughtful approach to maximize customer value, ensure the fundamentals of our distribution business remain sound, and maintain the flexibility needed as technology and our customers' expectations continue to evolve.

This Appendix discusses our grid modernization strategy that includes our Advanced Grid Intelligence and Security (AGIS) initiative, which is our long-term strategic plan to transform our electric distribution system to update system technology and capabilities. For the financial forecasts associated with our grid modernization plans, please see *Appendix D: Distribution Financial Framework and Information*. Overall, the AGIS initiative consists of multiple elements that work together to create a more modern and advanced distribution grid intended to meet changing customer demands, enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources.

Figure 1: Elements of AGIS Initiative



We discuss these and other technologies that are part of our grid modernization roadmap below.

We separately outline our customer strategy and roadmap related to AGIS and future grid modernization efforts as *Appendix B2: Customer Strategy and Roadmap* and the ways we intend to leverage the data for operational and planning purposes as *Appendix B3: Operational and Planning Data Management, Data Security, and Data Access Plans and Policies.* Finally, we note that protective cyber security controls and protocols are built into every step and technology underlying our overall plan, and are essential to operating a secure, technologically-advanced grid in today's world. We discuss our approach to data security in Appendix B3.

I. DRIVERS OF THE AGIS INITIATIVE

We have made incremental modernization efforts on the distribution system over many years, maintaining a grid that is reliable and as efficient as it could be with the technology it currently employs. We continue to monitor the changing landscape of customer usage patterns, policies and technical developments. All indications suggest our investments are coming at the right time and must continue. Drivers of our AGIS strategy remain:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills affordable,
- The Company's desire to meet the growing needs and expectations of our customers,
- Current distribution system needs, and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

We are working every day to lead the transition to a clean energy future, enhance our customers' experience with their utility, and keep bills low. Our customers can be partners in a more environmentally sound future, especially if they are empowered with better information and data to manage their energy usage and make conservation-friendly choices. Advanced Metering Infrastructure (AMI) and the associated components of the AGIS initiative are critical to these efforts. Distributed Energy Resources (DER) are also a key to this clean energy future, as are two-way communications connecting key elements of the distribution grid, down to the meter level. These are necessary changes to accommodate increasing levels of DER interconnecting with the system.

Further, customers are demanding more optionality and increasing levels of service from all their service providers – including their provider of electric service. The AGIS initiative is intended to create better interfaces with customers, provide them with better information and more choices, and thus improve their overall experience. Coupled with efforts to improve the digital platforms through which we interact with customers, improved energy management, control, conservation, and bill management are all available with a more interactive, advanced distribution system. And it goes without saying that continually enhancing our customers' reliability experience is at the core of quality electric service.

Finally, our AGIS initiative offers our customers opportunities to better control and manage their monthly bills by providing more timely and granular energy usage data and enabling advanced rate design. Additionally, the costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers. Our grid advancement strategy is intended to support each of these strategic objectives.

Influenced by other services, customers have come to expect more from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use. Customers also expect greater functionality and interaction in how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, EV chargers, smart home devices, and even smart phones and energy-related digital applications, are evolving at a fast rate.

While Xcel Energy customers today have access to numerous energy efficiency and demand management programs, renewable energy choices, and billing options, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Advanced electric meters can now more easily and flexibly gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can detect, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Xcel Energy has always performed well with respect to system reliability, management, and customer service – but in light of the prevalence of advanced meters and smart grid technologies, we must make similar investments to ensure continuing alignment with industry direction and customer expectations.

As recognized in the United States Department of Energy (DOE) Office of Electricity's November 2018 Smart Grid System Report to Congress, there is a broader need for attention to distribution infrastructure nationwide:[1]

> Our [country's] electric infrastructure is aging and it is being pushed to do more than it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.
>
> "Smart grid" technologies are made possible by two-way communication technologies, control systems, and computer processing. These advanced technologies include advanced sensors… that allow operators to assess grid stability, advanced digital meters that give consumers better information and automatically report outages, relays that sense and recover from faults in the substation automatically, automated feeder switches that re-route power around problems, and batteries that store excess energy and make it available later to the grid to meet customer demand.[2]
>
> It is no coincidence that these needs are arising at the same time we have implemented ADMS and that our existing AMR meters are nearing the end of their life. And, as noted earlier, our customers are also demanding more optionality, environmentally-sound investments, more control over their energy usage, and better outage management and communications from their utility.

Further, as the prevalence of DER continues to rise, the ability to manage these resources requires visibility into the grid and a more resilient and responsive grid. As the DOE Smart Grid Report stated, grid advancement is necessary to support:

> the increasing presence of renewable generation and the proliferation of customer- and merchant-owned DERs [that] are introducing significantly greater levels of variability and uncertainty in both the supply of electricity and the demand for it.

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[1] https://www.energy.gov/sites/prod/files/2019/02/f59/Smart%20Grid%20System%20Report%20November%202018_1.pdf, as of October 1, 2019 (internal citations omitted) (DOE Smart Grid System Report).

[2] https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid, as of Oct. 1, 2019.

> Generation and load profiles, which have been predictable in the past, can now vary instantaneously and are subject to the behavior of consumers where DERs are present.[3]

Enhanced grid management through an Advanced Distribution Management System (ADMS), meters with two-way communications that act as sensors, and greater sensing and control will all support our ability to host increasing levels of DERs.

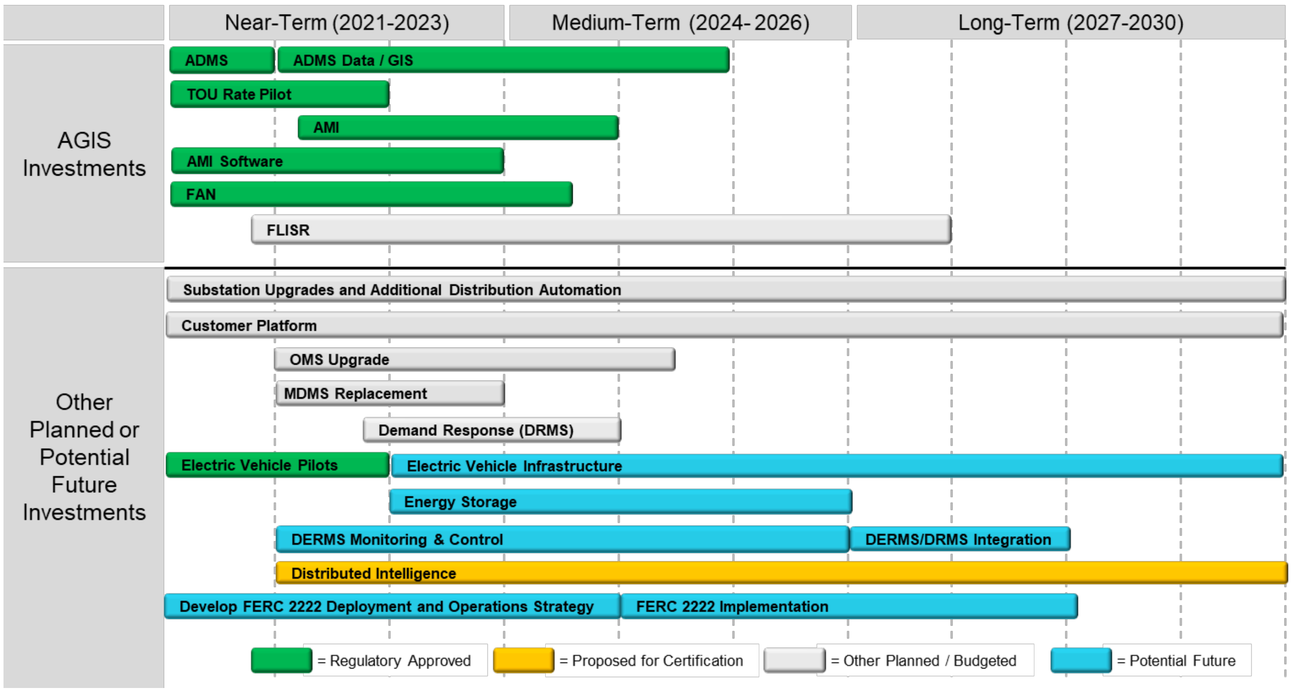
All of these circumstances helped to drive and form the Company's AGIS initiative. We are excited to modernize our system in a measured way that addresses system needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

II. GRID MODERNIZATION ROADMAP

As we have noted, our implementation of the first foundational components of AGIS is underway. However, our grid modernization plans include implementing additional technologies and capabilities over the long-term – also leveraging earlier components to deliver increasing value to customers as illustrated in Figure 2 below.

[3] DOE Smart Grid Report at p. 5.

Figure 2: Illustrative Long-Term Grid Modernization Plan



IDP requirement 3.D.2 (ii) requires the Company to describe the steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.[4] The U.S. DOE's Next Generation DSPx, Volume III provides a good reference for how to consider both the elements of a modern grid and their costs.[5] The DSPx report was sponsored by the U.S. DOE's Office of Electricity Delivery and Energy Reliability. This report was developed at the request of, and with guidance from, the MPUC among others like the California Public Utilities Commission (CPUC), the New York Public Service Commission (NYPSC), and the Hawaii Public Utilities Commission (HPUC).

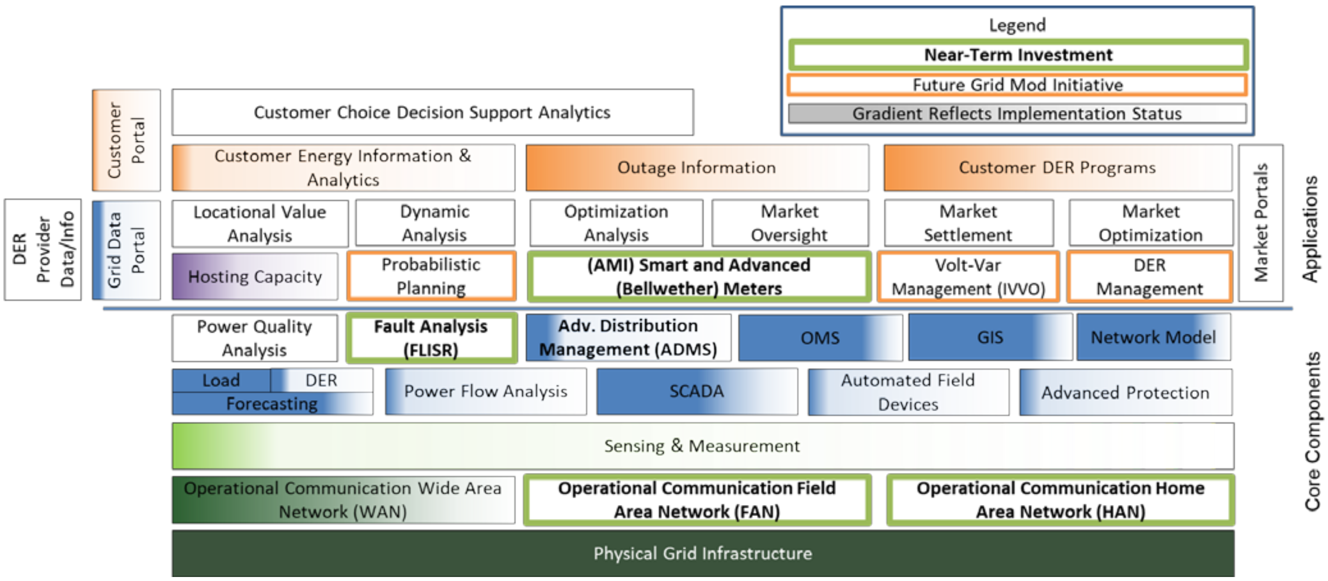
We portray our current state systems and processes against the DSPx framework as shown in Figure 3 below – developing "core components" as the foundation for our grid modernization roadmap first and subsequently building on that foundation to enable advanced applications, which is well aligned with the DSPx framework. As we discuss below, many of these core components are already in place, and others we are

[4] https://gridarchitecture.pnnl.gov/

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

poised to implement in the near-term – all of which will build additional core capabilities to support grid modernization applications.

Figure 3: Estimated Status of AGIS Implementation

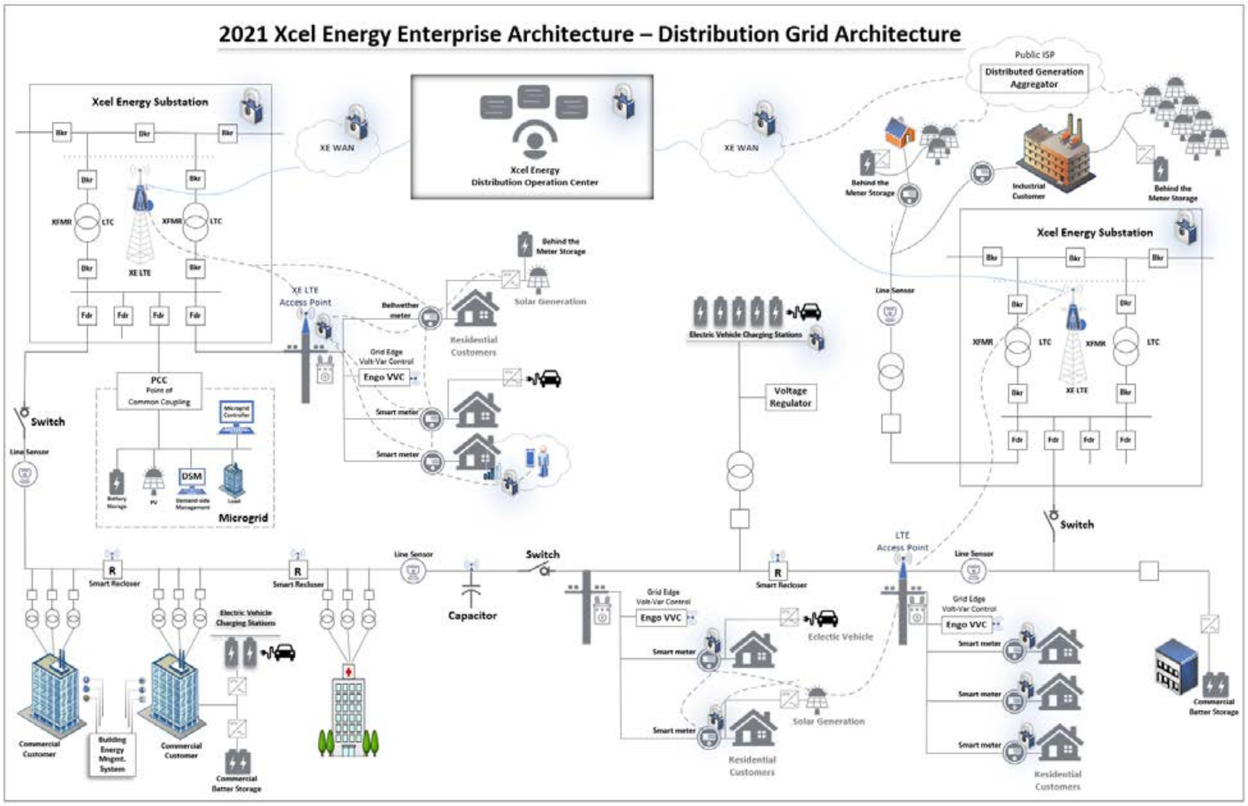


In addition to the DSPx framework, Xcel Energy developed its own Grid Architecture – a reference that aids in development of a plan to modernize the distribution system. Our Grid Architecture depicts System Architecture of our electric power grid – from control engineering, communications and networking, to organizational structure, and power markets. We employ architectural depictions to help communicate how our systems interact. It allows us to proactively examine our grid components, iterate and innovative on their integrations, and helps us improve our operations. Lastly, our Grid Architecture allows us to proactively manage our grid and enterprise risk by

- Identifying and addressing operational and functional gaps,
- Identifying and managing competing priorities, and
- Identify innovative opportunities that add to our business value and improve efficiencies.

Our AGIS initiative heavily used these architectural principles in each of its programs. Below depiction is useful to visualize the grid's emerging architecture.

Figure 4: Xcel Energy Enterprise Architecture – Distribution Grid Architecture



We have and will continue to use architectural principles in building these tools and to ensure they work efficiently and effectively with each other.

III. AGIS IMPLEMENTATION SUMMARY AND STATUS

While incremental modernization efforts have taken place on the distribution system over many years, and we have used these investments to provide reliable power for decades, our investments in ADMS, AMI, Field Area Network (FAN), and sensing and control technologies such as Fault Location Isolation and Service Restoration (FLISR) particularly begin a more significant advancement of the grid. These foundational elements, in concert with other future investments, will provide cumulative benefits over time and transform the customer experience by providing new, innovative customer programs and service offerings, developed internally and in concert with partners.

In this section, we outline each of the grid modernization technologies and initiatives we have underway or that is in our near-term plans. We note that we provide a high-level summary of the benefits of each of the grid modernization initiatives here and provide a more detailed discussion of the benefits in our Customer Strategy and Roadmap in Appendix B2. Also, as Appendix B3, we discuss data security and the ways that we intend to leverage the data for operational and planning purposes.

The AGIS initiative builds the foundation of our grid modernization plans and includes ADMS, AMI, the FAN, and FLISR. The Commission certified ADMS in 2016, and we began in-servicing portions of its functionality in Minnesota in 2021. The Commission certified AMI and FAN as an outcome of our 2019 IDP in Docket No. E002/M-19-666, and we will begin implementing that with customers in early 2022. We previously sought certification of an automated controls technology called Fault Location Isolation and Service Restoration (FLISR) that the Commission did not certify. We are however moving forward with this initiative as part of our multi-year electric rate case filed October 25, 2021, as we believe it will result in direct reliability benefits and operational efficiencies that also benefit customers' reliability experience.

A. Implementation Snapshot

Implementation of the near-term components of our AGIS plans will occur over several years and be substantially complete by 2024. We provide a snapshot of our implementation timeline in Table 1 below. Also part of our grid modernization plan and included in the timeline below is Distributed Intelligence (DI) which we are proposing for certification in this 2021 IDP.

Table 1: AGIS and Other Grid Modernization Technologies and Initiatives Deployment Timeline

Program	Implementation Timeline
ADMS	Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.
TOU Rate Pilot	Launched in November 2020 and expected to conclude in late 2022.
AMI	Meter deployment scheduled for 2022-2024
FAN	The implementation of FAN is underway. We started the initial network and security design in 2020 and installed and programmed the first FAN device in May 2021 and will continue installing FAN devices through 2024. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed.
LoadSEER	LoadSEER, was first used in Minnesota in September of 2020
FLISR	Installation for FLSIR devices (reclosers, switches, and substation relays) began in 2021 on select feeders.

That said, grid modernization is ongoing by nature, and we will continue to evolve our plans and leverage evolving technology, platforms, and optionality as appropriate over time.

B. Advanced Distribution Management System

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.

The Commission certified ADMS in 2016 and we began recovering the costs of ADMS through the TCR in Docket No. E002/-M-17-797.

1. Implementation

Starting with ADMS, in 2021 the Company made additional progress on the ADMS implementation. Prior to 2021, the Company completed many activities relating to the design, build, configuration and initial testing of the ADMS system. We completed the deployment of the ADMS hardware and software to production in 2020 and we have completed all Minnesota control centers' (3) "go-live" portion of the ADMS initiative in 2021. Going-live is the culmination of all necessary efforts to implement an operational system and occurs when the software begins serving its intended function. Specifically, this is when our control center operators began using the ADMS system as designed – which for the first control center go-live included monitoring and control of substations, field devices, and feeders. Since the first control enter go live in April 2021, the system has performed very well and has been extremely stable. We have experienced no system outages with continuous 24 hour by 7 days a week usage. Beyond the initial go-lives, we expect to expand the capabilities of ADMS over many years, which is part of the overall journey for integrating new devices to ADMS and leveraging its capabilities to enable additional functionality of ADMS, such as FLISR.

2. Benefits

ADMS will enable management of the complex interaction among outage events, distribution switching operations, 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.

C. Advanced Metering Infrastructure

Advanced Metering Infrastructure is the Company's metering solution, consisting of an integrated system of advanced meters, communication networks, and software that enables secure two-way communication between Xcel Energy's business and data systems and customer meters. These meters will be delivered with the potential for Distributed Intelligence (DI) – a powerful distributed processing capability which, when integrated into the Company's broader ecosystem of customer and grid management systems, will unlock both customer and grid-facing benefits. We note that we are seeking certification of the DI capabilities in conjunction with this IDP. See *Appendix G: Distributed Intelligence Certification Request* for our certification request.

The Commission certified AMI in our 2019 IDP proceeding. We will seek cost recovery of AMI through the TCR in our next TCR Petition that we expect to submit in November 2021.

1. Implementation

The implementation of AMI includes the deployment of advanced meters, communication networks, and software that enables secure two-way communication between Xcel Energy's business and data systems and customer meters.

The implementation of the AMI software is well underway, with the software that will be used to support advanced meters in all of our states successfully supporting advanced meters in PSCo since June 2021. In addition, we are planning a software release in January 2022 that will support advanced meters in Minnesota. We have additional software releases planned after the first advanced meters are installed in Minnesota to continue to build capabilities and to support the deployment of the different meter types and rates that are not part of the initial meters deployed at the start of 2022.

Meter deployment includes AMI hardware evaluation, testing, acquisition, configuration, and deployment of electric meter assets. The Company plans to deploy approximately 1.4 million AMI meters in Minnesota starting in early 2022 and completing the deployment by the end of 2024.

2. Benefits

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. As we have noted, the AMI meters include an embedded DI platform that has the potential to further enhance the distribution grid capabilities as well as the customer experience.

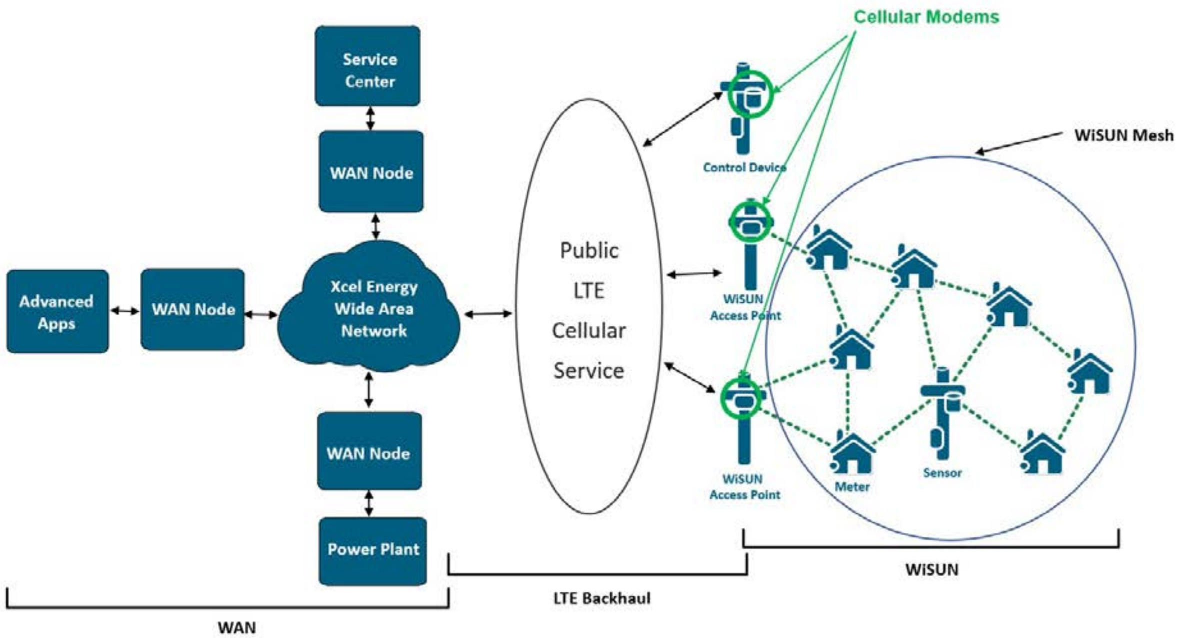
D. Field Area Network

The Field Area Network is a secure, flexible two-way communication network that provides wireless communications to, from, and among field devices and our information systems. The Commission certified FAN in our 2019 IDP proceeding. We will seek cost recovery of FAN through the TCR in our next TCR Petition that we expect to submit in November 2021.

The FAN will connect to the Company's pre-existing Wide Area Network (WAN), which is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications. The private fiber and microwave technologies are supplemented by leased circuits from a variety of carriers, as well as satellite backup facilities. The WAN provides high-speed, secure, and reliable two-way communications capability between our core data centers, office locations, service centers, generating stations, and substations. The WAN also provides primary and backup communication capabilities to key facilities in the Company's areas of operation.

The FAN consists of two separate wireless technologies. The first is a lower-speed, private mesh network. The second is a high-speed network backhaul to connect the mesh network to the WAN. The relationship between the mesh, backhaul and WAN are illustrated in the diagram below.

Figure 5: Field Area Network Illustration



1. *WiSUN Mesh*

Wireless Smart Utility Network (WiSUN) is a wireless communication standard designed specifically to facilitate communication between smart grid devices. The WiSUN mesh network consists of three main device types: access points; repeaters; and endpoint devices. An access point is a device that will link the Company's endpoint devices with the rest of our communications network. Repeaters are range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate. These two device types will be principally located on distribution poles and other similar structures. Endpoint devices include AMI meters and can include DA field devices, such as the intelligent FLISR field devices. 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.

In addition to being able to communicate with the WiSUN network infrastructure, the AMI meters are able to communicate with each other, becoming a part of a network mesh. This improves range of mesh coverage and adds redundant communication paths between the AMI meters and the WiSUN access points and repeaters.

2. Backhaul

The backhaul connects the WiSUN mesh networks to the corporate WAN. The backhaul will primarily consist of public Long Term Evolution (LTE) cellular service, supplemented by alternatives such as microwave or fiber where public LTE service is unavailable. LTE cellular modems are installed on poles, and are connected to the WiSUN infrastructure. Using a public LTE carrier (e.g., Verizon, etc.), these modems provide the backhaul connectivity from the WiSUN network to Xcel Energy's data centers.

3. Implementation

The implementation of FAN is underway. The FAN implementation includes the network design, the security of these networks, configuring the software and hardware components of the FAN, and the installation of FAN devices that are located primarily on distribution poles. The physical installation of FAN devices will be performed by Distribution field crews. We started the initial network and security design in 2020 and installed and programmed the first FAN device in May 2021 and will continue installing FAN devices through 2024. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed.

4. Benefits

The FAN provides the ability for the AMI meters (and potentially other automated field devices) to communicate with each other in a safe, secure, and reliable way. As explained above, these components work together to provide granular information regarding energy consumption and patterns of usage, which will allow customers to better manage their energy consumption and costs. This information will also allow the Company to offer additional programs to customers and facilitate our ability to quickly detect and respond to outages. The communication provided by the FAN is essential to supporting the benefits of the AGIS initiative and future grid modernization plans.

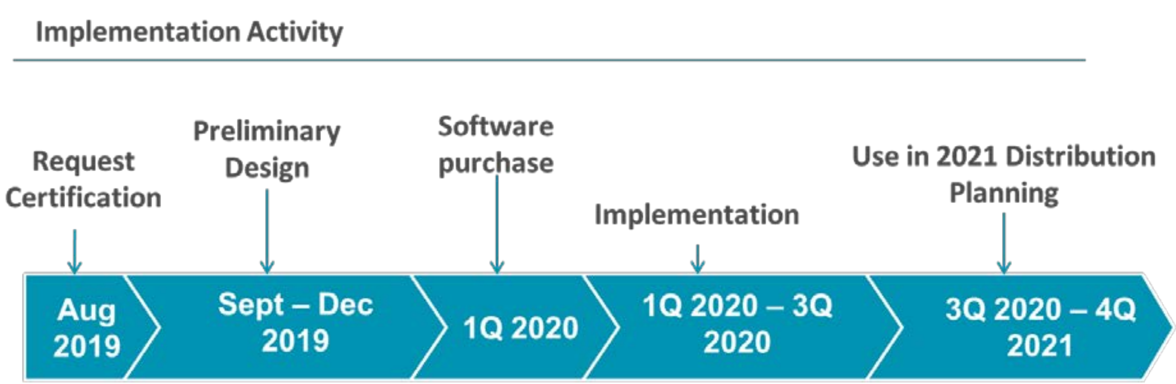
E. LoadSEER – Advanced Distribution System Planning Tool

LoadSEER, or previously referenced as 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. LoadSEER is a foundational planning tool that will enhance system reliability as well as supporting modernization of our distribution system. The tool replaced our previous forecasting tool that lacked the ability to provide the data granularity and transparency necessary to keep pace with customer expectations and evolving regulatory requirements. The Commission certified LoadSEER in our 2019 IDP proceeding. We will seek cost recovery of LoadSEER through the TCR in our next TCR Petition that we expect to submit in November 2021.

1. *Implementation*

After determining that LoadSEER is the best tool available to suit our distribution forecasting needs for the foreseeable future, we moved swiftly to procure and implement it. After finalizing the procurement, design, implementation, testing, which largely took place over the January through August 2020 timeframe, as shown in Figure 6 below. We implemented LoadSEER for use in our Upper Midwest in time to partially use it for our Fall 2020 planning process. We implemented it in our operating company affiliates Public Service of Colorado (PSCo) and Southwest Public Service (SPS) in 4Q 2020. LoadSEER is now the primary tool for distribution planning and load forecasting in Minnesota.

Figure 6: LoadSEER Implementation Timeline



2. *Benefits*

The LoadSEER forecasting tool provides various functionalities and benefits that make it an appropriate choice for our future distribution system planning. There are a number of key functions we used as guiding factors in tool evaluation and selection that will enable the range of analyses that will provide value to our customers and that meet our regulatory requirements. These functions include increased forecast granularity, providing data to support Non-Wires Alternative analysis, the ability to develop forecast scenarios, the ability to analyze distribution impacts of corporate-level load and DER forecasts, and increased ability to integrate with other planning processes. LoadSEER has the demonstrated ability to provide all of these functions.

F. Time of Use Rate Pilot

The Company proposed a Residential Time of Use rate design pilot in 2017 (Docket No. E002/M-17-1775). The Commission approved and certified the pilot in 2018.

1. Implementation

Our residential time of use rate design pilot, *Flex Pricing*, is underway. Initially planned for launch in April 2020, the Company delayed the pilot start until November 2020, as the initial launch coincided with the early stages of the state's stay at home orders related to the COVID-19 pandemic. The two-year pilot is focused on learning how customers respond to time of use price signals. It is nearing its half-way mark, and we look forward to reporting on mid-term findings in early 2022.

2. Benefits

The Company is piloting Flex Pricing in order to study customer responses to price signals, to explore and identify effective customer engagement strategies, and to understand customer impacts by sector. The pilot provides numerous benefits, including opportunities for customers to save on their utility bills. Participants receive advanced meters that facilitate communication between the utility and customer, in service of driving on peak energy efficiency and load-shifting behaviors. The pilot also enables increased communication capabilities, customer information and education, and targeted price signals.

G. Fault Location Isolation and Service Restoration

FLISR is an ADMS application that improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power.

We previously requested certification of FLISR through past IDP proceedings, but the Commission did not grant certification. We have included a FLISR initiative in the multi-year electric rate case we submitted October 25, 2021 and intend to recover costs through base rates, depending on the outcome of that case.

1. Implementation

We plan to deploy FLISR on approximately 208 feeders in Minnesota from 2021-2027. We are selecting feeders for the deployment of FLISR based on the following criteria: (1) five-year reliability performance that takes into account the number of customers per feeder; (2) planned or recently completed projects that impact a feeder's reliability performance; (3) constructability. We are still determining its complete list of feeders where it will deploy FLISR and will continue to reevaluate its feeder selection as the deployment moves forward.

2. Benefits

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.

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.

H. Distributed Energy Resources Management System (*future*)

As penetration levels of DER increase on our system, there is an increasing need to have more visibility and in some cases control to maintain a secure, reliable distribution system. Currently we are examining Distributed Energy Resource Management System (DERMS) capabilities in the market and will examine how it can help support higher DER penetration scenarios, NWAs and other distribution system needs.

A DERMS is generally described as a software platform that is designed to interact with DER on the distribution system. Capabilities vary from vendor to vendor but monitoring and control of DER are two important aspects, all which can help facilitate the integration of DER on the system and potentially help DER add more value to the grid. Potential use cases could involve monitoring and/or control of solar, energy storage, electric vehicles and other DER. Most DERMS systems also have demand response capabilities.

FERC Order 2222 enables aggregated DERs to participate in wholesale markets operated by RTOs/ISOs. The Company is a part of these discussions with MISO and MISO-served distribution utilities. Additional capabilities with local monitoring, market registration, or control may be needed, and a DERMS system may be able to fulfill some of these capabilities. We continue to monitor developments in this area. We discuss FERC Order 2222 in more detail in *Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/IEEE 1547*.

The Company is also participating in a multi-utility effort with SEPA to prepare a public report providing an overview about emerging DERMS technology. SEPA is a non-profit that consists of utilities, industry and other stakeholders focused on identifying and addressing regulatory, grid innovation and electrification complexities related to clean energy strategies. The study will identify emerging DERMS technology, develop various use cases that utilities can consider and help utilities understand the value that DERMS technology can provide. Key research questions include the maturity of DERMs technology today, procurement considerations and alternatives to DERMs technology. The report will be available to project participants by mid-2022 and available publicly one year later. We also learn about various utility efforts and technology through our participation in EPRI Programs, particularly Program 174, DER integration.

In summary, we anticipate the need for DERMS capabilities and is beginning to explore the best path to provide this capability and its benefits to our customers.

CONCLUSION

Our distribution grid is the foundation of the service we provide our customers. We are at a point where investment in new technologies to further modernize our grid will return significant value to our customers. Our AGIS and grid modernization plans support the Company's vision for an advanced grid that will provide both customer and operational benefits for many years to come and has been informed by:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low,
- The Company's desire to meet the growing needs and expectations of our customers,
- Current distribution system needs, and
- Commission policy and stakeholder input relative to customer offerings, performance, and technical capabilities of the grid.

Our grid modernization efforts will enhance transparency into the distribution system and provide detailed and timely data to promote efficiency, reliability, and enable increased distributed resources on our system. It will also enhance our customers' experience by providing access to actionable information, more choices, and greater control of their energy use.

APPENDIX B2: CUSTOMER STRATEGY AND ROADMAP

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicles, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now often equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Xcel Energy has provided its customers and communities outstanding service for over 100 years. We are also planning for the future – and have a vision for where we and our customers want the grid to go. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

Today, Xcel Energy customers have access to numerous energy efficiency and demand management programs, renewable energy choices, electric vehicle and charging options, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use

– and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The foundational investments in our AGIS initiative include:

- *Advanced Distribution Management System (ADMS).* A real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Advanced Metering Infrastructure (AMI).* 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 Energy's business and operational data systems and customer meters.
- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power thereby decreasing the duration of and number of customers affected an outage.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

I. CUSTOMER STRATEGY

Our grid modernization efforts aim to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect. Our customer strategy is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Figure 1: Customer Strategy Informed by Customer Expectations

Our implementation of the Advanced Distribution Management System in 2021 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with Advanced Metering Infrastructure and our ability to leverage the underlying and necessary Field Area Network to improve customers' reliability experience through Fault Location Isolation and Service Restoration, and more.

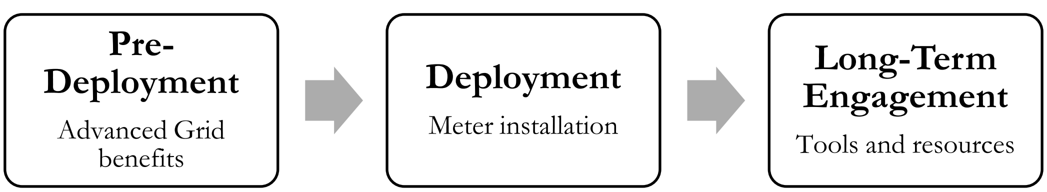
Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.

Figure 2: Customer Value through Lifecycle

	Awareness	Start/Stop/ Transfer	Billing & Payments	Ongoing Use	Support & Service	Lifestage & Lifestyle
What do customers expect?	A **trusted, responsible source** helping customers learn more about environmental initiatives, energy programs and regulations	An **intuitive, frictionless** experience that doesn't contribute to the stress of moving	**Flexibility** and **options** (i.e., variety of payment methods), **transparency** around monthly costs	**Monthly usage insights** allowing customers to manage costs; a **robust offering of energy efficiency programs** aligned to customers' interests	**Increased visibility** during electric outages and delivery of other services; a service organization that **advocates for the customer**	A **go-to resource** for information and solutions regarding **renewable energy** and **smart homes** Energy management technology
Examples – AGIS Enabled Experience	**Integrated communication plan** across channels and timeline.	**Remote Connect / Disconnect** **Real-time meter reads**	**Bill forecasting** **Bill prepayment**	High bill alerts Energy usage goals TOU alerts Disaggregation	**Outage ERT accuracy** **Arch detection**	Distributed Energy Resources Home automation/remote monitoring
Examples – Customer Value	A feeling of comfort with the changes and timely and relevant communications.	Avoid gaps in service Easier moving experience	Increased bill predictability. Payment flexibility. Better understanding of their monthly bill.	Timely alerts and messages to guide their energy use and add predictability to their bill.	More timely and accurate ERT messages. Predictable home health and safety.	EV, Battery, Solar installation readiness and reduced friction Control over usage in the home.
Examples – Business Value	Customer satisfaction Reduced call volume	Reduced truck rolls Accurate meter reads Reduced call volume	Customer satisfaction Reduced B&P call volume	Customer satisfaction Energy savings More predictable load	Customer satisfaction Reliability Reduced call volume	Customer satisfaction Reliability

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 3: Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

A. Customer Research

To develop the customer strategy, Xcel Energy committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about technology and enabling improvements than process*. Safety and energy savings rated most highly.
- *Addressing service interruptions are important to all customer classes*. Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent in scope and duration.*
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs.* Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- *Building trust is a key component to unlocking value.* Trust is best built by identifying solutions and showing results specific to the customers
- *Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.*

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

B. Expected Grid Modernization Outcomes for Customers

As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security and reliability, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

II. VIEW INTO THE FUTURE FOR CUSTOMERS

A. The AMI-enabled Customer Product and Service Roadmap

Rather than simply evolving from our current state, we are revisiting our entire customer experience. Today, customers expect that we *know them* and take a personalized approach to their relationship with us; they expect that we keep them *informed* and use our expertise to *advise* them about what to do and then *empower* them to take those actions; and finally, that we *deliver seamless* experiences for them reducing the burden on them to take action.

Figure 4: Customer Experience Priorities

In order to *know* our customers, *inform, advise, and enable* them, and *deliver seamlessly* we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and motivations regarding the benefits and value of an advanced grid investment from their point of view. As detailed above, we conduct robust customer research and continually update that research to ensure we are reactive to our customer's perceptions. It also requires our organization to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

In the following sections, we provide more details on the types of products and services we will offer in the future that fit within these categories. These products and services are currently in development and we have provided an expectation of when we expect to begin delivering on these products and services. However, it is important to reiterate that the anticipated delivery dates are not the final states of these offerings. We will continually innovate and iterate these offerings and incorporate new benefits and opportunities as they become available to us. This may include adapting offerings to incorporate DI capabilities, transitioning traditional opportunities to DI applications, or integrating new technology that is not yet in the market.

B. Enhance the Customer Experience

Table 1: Integrated, Seamless Interactions

Product or Service	Customers Affected	Timing
Green Button Connect My Data For customers who would like to automatically transmit their usage information to third parties, Green Button Connect My Data will also be available in the customer web portal for ongoing automated transfers.	**Residential** **Small Business** **Large C&I**	**Day 1**
Enhanced Web and Mobile Applications Customer account information along with options to view and pay bills, visualize energy usage and trends, and manage outages will be presented to customers in an integrated and highly personalized format. This is made possible by granular information and analytics as well as a robust customer preference center. As discussed below, DI applications will greatly enhance both the Web and Mobile Application experience.	**Residential** **Small Business** **Large C&I**	**Day 1**
Energy Usage Dashboard Within the new web and mobile customer portals, energy usage dashboards will inform customer about their energy usage of both the overall facility as well as individual devices in a home or business. Compares data to a comprehensive database of similar products to alert to opportunities to save energy and money. Dashboards can be customized to both residential and C&I customer needs. As described above, DI applications will enhance these visualizations over time by providing increasingly accurate and timely appliance disaggregation.	**Residential** **Small Business** **Large C&I**	**Day 1**
Energy Usage Alerts and Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include high usage alerts, TOU peak period, Peak Day notification, or goal-based alerts. With DI, alerts can be made to customers in near real time and predict a broader range of anomalies, including appliance health.	**Residential** **Small Business** **Large C&I**	**Near Term**
Personalized Notifications Communication systems will be enhanced to provide timely information to customers in a form that is personalized to their lifestyle and preferences. With DI and HAN, new channels for communication are enabled in addition to increasingly real-time and proactive notification.	**Residential** **Small Business** **Large C&I**	**Near Term**
Artificial Intelligence Enabled Notifications As artificial intelligence technologies mature and become widely adopted in the market, meters will have the ability in DI to leverage these capabilities to provide heightened interactions which will be customized to the unique needs of each customer.	**Residential** **Small Business** **Large C&I**	**Future**

Table 2: Safety & Reliability Enhancements

Product or Service	Customer Affected	Timing
Outage Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include proactive messaging about an outage, automatic restoration, and restoration confirmation.	**Residential Small Business Large C&I**	**Day 1**
Power Quality Analysis With detailed information collected by the meter relating to power delivery, customers can more accurately and frequently assess their power quality. Over time, analytics of the power quality information can help flag and diagnose potential power quality related items so that customers can proactively manage any possible issues. DI applications in this area will provide much more granular and real-time information.	**Residential Small Business Large C&I**	**Near Term**
Emergency and Safety Notifications With DI, the meter will be able to provide customers with emergency management notifications via its analytics and communications capabilities. This can help customers identify potential risks to their energy management systems, security monitoring, and be aware of local emergency notifications that may apply to their general safety and security.	**Residential Small Business Large C&I**	**Near Term**
Enhanced Microgrid Integration Where the capability exists for portions of the grid to operate independently of the rest of the surrounding system, the advanced distribution management system will more seamlessly be able to manage the connection of these microgrids.	**Residential Small Business Large C&I**	**Future**
Smart Safety Disconnect With a DI application, the meter will be able to detect when a smart inverter has malfunctioned or was improperly installed and has not disconnected from the grid when incoming power has been lost. In this situation, the disconnect inside the meter is automatically tripped to protect the rest of the grid and the customer.	**Residential Small Business Large C&I**	**Future**
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored. This service will likely require a DI application.	**Residential Small Business Large C&I**	**Future**

C. Lead the Clean Energy Transition

Table 3: New Distributed Energy Resources Programs

Product or Service	Customers Affected	Timing
Enhanced Access to Battery Storage and Electric Vehicles Through the enhanced visibility and control of the distribution system, greater utilization of storage elements on the grid, including electric batteries and electric vehicles, will be possible. This capability promises to help ensure safe, reliable energy for all customers.	**Residential Small Business Large C&I**	**Near Term**
Green Notifications and Controls Customers would be notified when the percentage of electricity generated by renewable services in their area exceeds a certain threshold. DI applications could be used to increase the accuracy and timeliness of these communications.	**Residential Small Business Large C&I**	**Near Term**
Enhanced DER Enablement Through the enhanced visibility and control of the distribution system, customers will be able to integrate distributed generation resources more seamlessly and potentially at higher levels within a given area. DI applications can assist in this aspect by providing higher levels of confidence regarding DER identification.	**Residential Small Business Large C&I**	**Near Term**
Demand Management Optimization With more granular consumption information, new demand management programs can be created to enable customers to shift and shed load to respond to needs of the grid on an increasingly real-time basis. With new communication capabilities enabled by HAN and DI, the meter will be able to communicate directly with smart devices within homes and businesses. As analytics such as disaggregation and virtual submetering evolve, demand response routines can increase sophistication through optimizing sequence among various demand response resources.	**Residential Small Business Large C&I**	**Near Term**

D. Keep Bills Low

Table 4: New Energy Saving Programs

Product or Service	Customers Affected	Timing
Virtual Energy Audits Provides an on-demand or periodic assessment of the energy usage/efficiency of a premise based on actual performance versus expected performance based on various parameters (i.e. size, year, build, occupancy, devices, etc.). With disaggregation and other analytics capabilities made possible by AMI, and enhanced with DI, these audit results will improve over time to provide more accurate and relevant information. Audits may also be used to monitor the health and status of appliances to identify opportunities for customer to reduce maintenance costs and improve energy efficiency.	**Residential** **Small Business** **Large C&I**	**Day 1**
Whole Facility Monitoring C&I customers with long-term sustainability goals can more easily track progress at the whole facility and sub-system level through integrations between meters and customer-operated energy management systems. This information can be used to verify savings over time for the purposes of demand side management or can be used to alert customers when demand or energy usage projections are expected to exceed threshold amounts over a given period of time.	**Small Business** **Large C&I**	**Near Term**
Enhanced Control Options for Behind the Meter Systems From the smart home to intelligent buildings, AMI meters will be able to communicate more seamlessly with devices and systems within the customer facility. Customers can use this capability to participate in demand response programs as well as to manage facility energy consumption in a more accurate and robust way.	**Residential** **Small Business** **Large C&I**	**Near Term**
Enhanced Automated Demand Response As the grid evolves, distribution system management can utilize expanded automated demand response capabilities which respond to real time needs of the distribution grid. Real-time communications with devices and systems in the home or building would be enabled by DI and HAN.	**Residential** **Small Business** **Large C&I**	**Future**

E. New Rate Options

Table 5: New Rate Options

Product or Service	Customers Affected	Timing
Rate Advisor With granular usage information and analytics capabilities made possible by AMI, the company will provide a multi-channel approach to educate customers and proactively offer ways to optimize energy usage and cost under existing and new, future rates schemes.	**Residential Small Business Large C&I**	**Near Term**
Time Varying Rates With more granular consumption data and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers can take advantage of these price signals to manage costs.	**Residential Small Business Large C&I**	**Near Term**
Virtual Submetering Instead of installing physical submeters, which are costly and take special wiring and their own communications channels, the main meter could act as a virtual submeter through disaggregation capabilities at the meter with DI.	**Residential Small Business Large C&I**	**Near Term**
Smart Rates New rate opportunities including pre-pay and technology specific rates are possible through a combination of AMI and additional DI applications. Rates may rely on local management of the premise level grid or local identification of events. For example, when an EV is plugged in, this could be detected and an EV rate is automatically applied. Another example, would be a flat billing rate with use of the Premise Level Grid Management System (PLGMS) to stay within the agreed to usage levels.	**Residential Small Business Large C&I**	**Future**

F. Distributed Intelligence

Distributed Intelligence (DI) refers to the distribution of computing power, analytics, decisions, and action away from a central point to the "edge" of the distribution grid. DI distributes these utility functions closer to localized devices or platforms, such as advanced meters or other "smart" devices on the distribution grid.

Xcel Energy's selection of DI-capable advanced meters has ensured that metering infrastructure can easily transform through time without having to replace metering technology as standards evolve. DI creates a platform for integration of changes in technology over time which was a functionality that previously did not exist with earlier generations of advanced metering infrastructure.

This DI Roadmap outlines the Company's near-term vision to utilize DI capabilities in its electric service territory in Minnesota, consistent with the goals of the Company's Advanced Grid Intelligence and Security (AGIS) initiative.

Deployment of DI capabilities is consistent with the Company's strategic objectives to lead the clean energy transition, enhance the customer experience, and keep bills low as DI capabilities further enhance:

- the benefits to distribution operations that Public Service's AGIS initiative provides by increasing the level of grid intelligence that can be achieved;
- the customer experience by providing customers more detailed and informative insights regarding their energy usage; and
- the effectiveness of programs approved by the Colorado Public Utilities Commission (Commission) to reduce carbon emissions.

The analytics made possible through DI can provide additional insights to assist customers make more informed decisions about their energy usage, increase the ability to connect customers to energy efficiency or demand-side management programs, and, increase the efficacy of time-differentiated rates. As such, DI has the potential to enable or enhance much of the AMI-enabled product and service roadmap, discussed above.

III. DI SOLUTIONS & USE CASES

Through the development of foundational DI infrastructure and initial use cases enabled by DI, there are significant opportunities to increase grid intelligence, enhance the safe and reliable operation of the distribution system, and improve the customer experience by providing customers access to information to better manage energy in their homes.

The Company envisions that certain foundational solutions provide the greatest near-term value to grid operations and customers and plans to develop basic functionality and focus on enhancing the safe, secure, and reliable operation of the grid and then to support customer programs already approved by the Commission. Solution categories for initial development include customers' Home Area Networks, certain grid-facing use cases, and customer-facing use cases that provide certain energy insights.

A. Home Area Network Connectivity

The Home Area Network (HAN) connectivity capability in the meter provides Wi-Fi communications between the advanced meter and Wi-Fi enabled devices behind the meter in the customer's home. The first version of this technology in conjunction with DI will enable customers to access their near real-time energy information through a mobile application that runs on Apple or Android smartphones. Through this first application, customers will be able see their one-second kilowatt ("kW") and five-second kilowatt-hour ("kWh") reads. This information will be sent from the meter via a DI application over the customer's home Wi-Fi network and directly to their smartphone and then displayed in a number of useful formats.

B. Grid-Facing Use Cases

Itron Inc. has applications that are available to today from Itron, Inc. (Itron) that have potential to be deployed with other infrastructure requirements benefit to the Company's overall operations, improving reliability for customers. Grid-facing use cases that the Company intends to test focus on safety and protection and increasing grid operational efficiencies. Specific initial grid-facing use cases include:

- <u>Power Quality Analysis:</u> Enhance power quality investigations with evaluation and analysis of voltage sag/swell events, harmonic insights, and waveform data.
- <u>Secondary Equipment Assurance:</u> A combination of two available solutions <u>from</u> Itron today —high impedance detection and open secondary neutral. These DI solutions could allow the Company to proactively identify, and therefore address, conductor deterioration or unbalanced voltage on the system that could impact customers (e.g., through voltage flickers, outages, etc.).
- <u>Connectivity Model:</u> Enhance GIS modeling of the distribution system which will enhance the effectiveness of ADMS, OMS, TLM, and fault location.
- <u>Power Theft Detection:</u> Identifying patterns that could identify power theft when a customer is bypassing, trapping, or line hooking. Not only is this a critical safety issue for customers, but power theft also increases the Company's overall cost of service.

C. Customer-Facing Use Cases

Customer-facing use cases provide foundational insights into energy usage overall and for devices (including EVs) in the home. DI on the meter as well as analytics off-meter, can allow customers to see energy usage by major devices, and potentially understanding usage and spend on an hourly, daily, weekly, or monthly basis. These insights could be combined with approved time of use pricing structures and other approved Company programs to provide customers better opportunities to optimize their spend and/or carbon profile

Notifications could be sent to customers when devices or overall usage in the premise exceed customer set targets, giving them critical, timely information to better manage their overall monthly energy costs. Current energy efficiency programs approved and offered by the Company can be better tailored to customers based on this information.

Additionally, when customers first plug in an EV into their premise, an extension of the same technology that enables the energy insights above could also detect the presence of an EV. That can enable several important benefits for both the customer and the Company. Most importantly, it provides critical information regarding growing EV penetration on the system, allowing the Company to better manage and plan its distribution operations for the changing load dynamics. Further, EV Detection can provide a channel to introduce customers to Commission-approved Transportation Electrification Programs, providing customers greater visibility to available programs to reduce their overall cost of EV ownership.

The end result – customers get better visibility into energy usage in their homes, allowing them to take greater control over their spend and carbon-profile.

Customer-facing use cases that the Company intends to develop to enable the above include:

- Energy Insights
  - *Energy Analysis Over Time:* Provide insights from various data sources based on time of day and appliance type throughout the home;

  - *Energy Analysis Against Peers:* Provide comparative insights from neighbors based on various data resources gathered on time of day and appliance type throughout the home; and

  - *Energy Hog Notification:* Provide notification of devices and/or appliances in the home that are drawing significant electricity load.
- Electric Vehicle (EV) Detection: Identify the presence of an EV at a customer premise when they plug in based on unique electric load characteristics.

As AMI installations begin in 2022, the Company intends to begin testing Itron-available grid-facing solutions described above as introduce the initial customer-facing solutions. Initial work to deploy DI capabilities will be focused on establishing the technical architecture required to enable DI solutions. As outlined in the certification request, these activities and investments will inform future development upon the DI platform.

APPENDIX B3: OPERATIONAL AND PLANNING DATA MANAGEMENT, DATA SECURITY, AND DATA ACCESS PLANS AND POLICIES

Beginning in 2016, Xcel Energy initiated a concerted effort to modernize its electric distribution system designed to maximize customer value, ensure the fundamentals of our distribution business remain sound, and maintain the flexibility needed as technology and our customers' expectations continue to evolve. This effort has led us to invest in new systems and field devices including an Advanced Distribution Management System, advanced infrastructure meters (AMI), a two-way field communications network (FAN), the installation of smart field devices, and procurement of a new distribution planning tool. This foundational investment is further augmented by investments in new software platforms and advanced systems such as Distributed Intelligence (DI), a capability of our AMI meters, and Fault Location Isolation and Service Restoration (FLISR). These technologies and tools facilitate greater data capabilities for customer-facing products and services as discussed in Appendix G – and for grid-facing purposes, as discussed in below.

I. GRID MODERNIZATION TECHNOLOGIES

A. Advanced Distribution Management System

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.

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 automated field devices and 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.

Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, and automated sensors and controls we deploy on the system such as FLISR in the near-term; it also prepares the Company to implement advanced applications like Distributed Energy Resource Management System (DERMS) in the future.

We have discussed the specific data capabilities and functionalities – and the benefits of those – in our past certification and cost recovery filings. Most recently, see Appendix 1A of the Company's November 15, 2019 2019 Transmission Cost Recovery Rider in Docket No. E002/M-19-721 and the Company's ADMS Annual Report dated January 25, 2021 in the same docket along with Docket Nos. E002/19-666 and E002-M-20-680.

B. Fault Location Isolation and Service Restoration

FLISR is an advanced application that utilizes ADMS, FAN, and substation and field device-sensing and control technology that is intended to reduce the number of customers impacted and outage duration for mainline outages. FLISR works when a fault is detected on the mainline portion of a feeders, predicting the fault location, isolating the fault, and restoring power to the unfaulted portions of the feeder. The implementation of FLISR (and in some locations, Fault Location Prediction or FLP) introduces a need to analyze the impacts (reporting) but also brings analytical opportunities that will enable our engineers to further improve our system. These data combined with AMI's Distribution Intelligence (see below) insights can provide engineers fault data unavailable before. Importantly, we note that the data alone will not provide value; data analysts are necessary to turn the raw data into information – and skilled engineers are necessary to turn that information into actions.

For more information on the FLISR technology, see the Company's multi-year rate case filed October 25, 2021 in Docket No. E002/GR-21-630.

C. LoadSEER – Advanced Planning Tool

We started to implement our new LoadSEER advanced planning software in 2020. It accepts a broad range of inputs, from load profiles, historical SCADA data, insights into the nature of the loads, DER, and socio-economic inputs. We expect that as we include this data, and apply both classic data analytics and Artificial Intelligence, we will unearth unanticipated correlations from which innovations will evolve.

For more details about LoadSEER, see the Company's certification request for an "advanced planning tool" in our 2019 IDP, filed November 1, 2019 in Docket No. E002/M-19-666. See also *Appendix A1: System Planning* of this IDP.

D. Advanced Metering Infrastructure

Advanced meters measure and record granular usage data (also called interval data) and a host of new operational data. The data from advanced meters include meter readings, interval energy usage and voltage information, power outage and restoration events, power quality information and other data. We discuss our plans for how we intend to improve service to our customers as a result of our implementation of AMI and other grid modernization advancements in Appendix B2.

1. Planning

From an operational and planning perspective, 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. We will use this data 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.

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.

2. Outage Operations

AMI will also enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System (OMS)[1]" This data helps utility

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[1] Power loss information is identified by an AMI meter's "last gasp," which is a 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.

personnel respond more quickly to fix problems with the end result being that customers' power is restored more quickly. These automatic outage notifications provide the Company with timelier outage notification compared to today when we are aware of outages after customers report them . Also, AMI allows for verification of power restoration, which is accomplished when a meter "reports in" after being reenergized. This will provide automated verification that power has been restored to customers, there are no nested outages, and all associated trouble orders are closed before restoration crews leave the areas. 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.

3. Other Field Efficiencies

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 efficiencies in several areas:

- Reduction in Outage Trips due to Customer Equipment Damage
- Cost Savings from Remote Connect Capability
- Reduction in "Ok on Arrival" Outage Field Visits
- Reduction in Field Visits for Voltage Investigations

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 software systems such as ADMS, system operators will have more insight into the distribution grid and for example be able to operate system with greater amounts of distributed generation.

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.

4. Automated Service Switch

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. In addition, while automated meter reading 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 customers' pets and traversing unfamiliar properties.

5. Other

Below we provide a table that summarizes other features and capabilities of AMI meters.

Table 1: Summary – Other AMI Features and Capabilities

Feature/ Capability	AMI
Time of Use (TOU) data	Supports more complex TOU rates and meters can be remotely programmed to capture TOU data
Interval data	Capable of measuring and recording more complex interval data sets; supports more interval data lengths. Meters can be programmed remotely to capture different intervals.
Real time notification of power outages	Real-time availability of outage information
Fast response to customer inquires	Real-time access to customer metering data and diagnostic information
Ability to remotely upgrade metering devices e.g., firmware upgrade, meter configuration changes	AMI offers the platform to remotely perform such functions.
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.
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.
Remote availability of meter diagnostic data useful for remote troubleshooting	Data available with full AMI systems.
Remote reconnection/ disconnection	System supports remote reconnect/disconnect of residential type customers and limited small commercial customers
Electric vehicle interconnects	Allows EVs to more readily utilize TOU pricing and provides load data to detect potential voltage issues.
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.
Reliable methods for detecting energy theft	AMI offers the platform that can be used to detect energy theft conditions.

For more details about AMI, see the Company's certification request in our 2019 IDP, filed November 1, 2019 in Docket No. E002/M-19-666.

II. DATA SECURITY AND PROTOCOLS FOR GRID MODERNIZATION

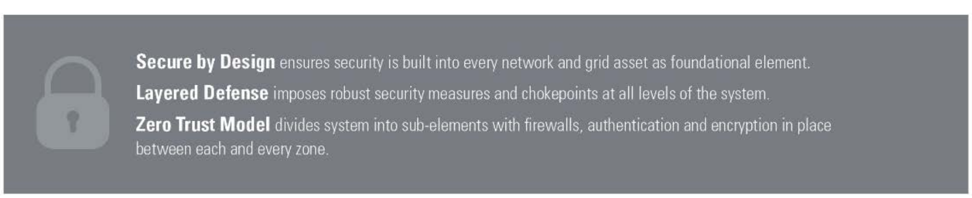
In this section, we discuss our approach to data security for our grid modernization plans. Protective cyber security and information technology support underlie all these components, as they are essential to operating a secure, technologically-advanced grid in today's world.

A. Overall Approach to Security

The Company has a dedicated Enterprise Security and Emergency Management (ESEM) business unit that encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption. The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that mitigations and responses can be planned that are proportional to the risk.

Generally, our security practices include a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST) Cyber Security Framework. The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect the Confidentiality, Integrity and Availability of information and systems. A rigorous vendor security risk assessment process helps to reduce supply chain risk.

Figure 1: Key Security Components



We implement cyber security controls not only for systems within the enterprise data centers but also for the intelligent devices (including meters) and communications networks outside of the company premises. Where technically feasible, these include but are not limited to user access controls, encryption, firewalls, intrusion detection and prevention systems (IDS/IPS), vulnerability and patch management, system change and configuration management, monitoring, and incident response planning.

Our cyber security program may best be described in terms of the five categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover. Combining these adds multiple layers of protection and detection including defenses at each endpoint and throughout the network. Controls within these layers include:

- *Asset management* – maintain an inventory and securely configure assets, so we know what to protect as well as what is authorized to access our networks [“Identify”],
- *Protection* – user access controls, encryption, digital certificates and other controls to ensure the confidentiality, integrity and availability of data [“Protect”],
- *Vulnerability management* – in addition to scanning equipment for known security vulnerabilities, the Company monitors emerging threats [“Detect”],
- *Monitoring and alerting* – identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient [“Detect”],
- *Incident response* – analyze information using playbooks and escalate to the Enterprise Command Center, the Company’s 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation [“Respond”], and
- *Disaster recovery and business continuity planning* – to efficiently maintain and restore grid operations in the event of a cyber-attack [“Recover”].

We will apply these controls to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

Endpoint Protection is the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at an endpoint. These were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and headend servers.

Access Control is to confirm that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication methods.

Authentication is a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, Xcel Energy requires multi-factor authentication so that a user must not only know their password, they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.

Authorization is the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals have the ability to make administrative changes.

System and Patch Management addresses the periodic manufacturer updates to software and firmware to improve performance, add features, or address security vulnerabilities. A robust system patch management process incorporates asset inventories, secure receipt of patches from the vendor, testing and deployment to the field. The Company's threat intelligence and vulnerability management teams monitor for and inform support teams of known security vulnerabilities that require patching. Keeping current with vendor patches helps reduce the possibility that a criminal can use a known exploit to compromise our systems or data.

Data validation is a final defensive layer between the various endpoints. As data is sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

B. AGIS Security Approach

Overall, while the implementation of the AGIS and other grid modernization initiatives solves certain existing issues, it also presents different challenges to security than a less advanced grid, and requires its own comprehensive security strategy. It starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. First, devices in the field must be protected. Unlike internal business technology, the distribution components are out in the field and at customers' residences; devices can only be hardened so much, and security must also rely on other controls. For example, detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity.

Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, adding a communications network that provides additional capabilities and services to our customers, as well as greater insight into our system, also enhances the potential impact of a security compromise. That said, we are designing security controls for each component and system implemented. These security risks can be organized into three primary areas: compromise of meters and devices; exploitation of the communications channels; and security lapses once data is within the corporate environment. There are also security risks related to cloud-based components including the customer web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid that we are also proactively addressing prior to implementation.

We have based our controls on a security controls governance framework that leverages industry best practices including the National Institute of Standards and Technology (NIST), Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against CIA (Confidentiality, Integrity and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

C. AMI Infrastructure and Communications Overview

In this section, we discuss the controls at various points of the AMI infrastructure. These components, starting at the meter, are as follows:

- The meter sits at the customer premise, gathering metrology data to be sent to the headend for billing purposes. The meter may also employ DI agents, to gather information for electric grid optimization, or to provide the customer with additional information and capabilities for managing their energy usage.

- The meters are a part of the field area network (FAN), a communications mesh that transmits information to and from the AMI headend. FAN communications end at an Access Point, which forms the transition from FAN to WAN (wide area network) and the company's internal network.
- Once on the company's internal network, data may move between network segments as allowed by firewalls and other security controls. Ultimately, data is stored on servers that reside in the Company data centers or is securely moved to secure locations in the cloud.
- Company employs layers of security controls to protect the confidentiality, integrity, and availability of data throughout this journey.

We discuss these infrastructure components below.

1. *At the Meter*

Our Company and AGIS security approach is one of "defense in depth." The advanced meters will be physically sealed and monitored to detect tampering. Customer usage data is well protected on the meter. Attempts to physically open or otherwise access a meter trigger tamper alarms. No customer-identifying data is held in the meter. DI agent processing is primarily done in dynamic memory rather than stored on the meter. The Company has performed extensive security penetration testing in these areas, as well as to confirm the separation of metrology data and communications from that used by DI agents.

Advanced meters and other networked devices have an network interface capabilities that enable them to connect to the FAN. We leverage both physical and cyber security controls to protect these network interfaces from unauthorized access. Second, a compromise of the FAN communications protocols that carry "traffic" to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore, it is paramount to protect the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels. It is also important to implement the correct level of monitoring and alerting, configured to identify potentially anomalous activity, so that both proactive and reactive responses are appropriate and efficient. Third, the primary risk to systems and information that reside within the Company's corporate environment is from unauthorized access – where a criminal or unqualified employee accesses sensitive data or issues commands to the grid. There are many controls in place to prevent and detect such behavior, including segmenting the AMI system from the corporate business network.

Meter communications will be encrypted to protect the privacy of our customers, as will the other communications that travel on the FAN from and between the authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The AMI head-end will validate the integrity of the data received. We will actively monitor the communications path between the meters and the Company data centers to promptly detect and respond to any anomalous activity. Additional monitoring of the head-end system will trigger alerts for investigation.

2. *On the FAN*

The equipment that makes up the FAN deploys the endpoint protections discussed above. Additional key controls for FAN include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic on their way to the AMI headend; monitoring and log review, as well as response to suspected security events. All member devices on the FAN have digital certificates, which prohibits rogue devices from joining the network, so traffic cannot be rerouted or invalid information injected into the network. The mesh portion of the FAN is also Company-owned, granting Company the control to deploy and monitor security settings.

Firewalls are placed in multiple areas of the network between the customer meter and the company data center/head end. By default, all traffic through a firewall is blocked, and authorized only after a thorough review and change process. With a firewall, any unauthorized, unregistered devices that attempt to join the network or communicate to/from devices are blocked.

Encryption uses complex mathematical algorithms to obscure data prior to and during its travels through the communications network. It also prevents data from being altered. Only authorized parties to the transaction (sender and receiver) have the “keys” to encrypt and decrypt data.

3. *Company Systems and the Internal Network*

The Company systems comprising and supporting AGIS reside in data centers with physical access protections – only authorized users are able to enter these locked facilities on Company property. Data accessed from the control centers travels from the systems in the Company data centers over the corporate network. At the control center, application users must follow the same rules for authentication, authorization, and least privilege.

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communications will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to ensure tampering has not been performed on the data packet. Once the data has been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

The Company segments its networks, so that critical operational systems and information are kept separate from business data and operations including email. This segmentation adds a significant barrier should a criminal compromise a corporate user's account. In addition to using firewalls between networks, the Company requires the use of multi-factor authentication when accessing systems from outside the control center.

After clearing firewalls, data from the FAN is routed through the internal network (and more firewalls) to the AMI headend. Meter readings are sent to other systems for processing and preparation of bills. DI data is sent to an application server in the data center which sits in a secured network segment (DMZ) where it is accessible to Company users and to Itron, which is responsible for management of that server, including patching and other security controls.

Physical access to the Company data centers is tightly controlled and periodically reviewed for business need. Data in systems controlled by Company is protected with layers of controls, including but not limited to access, encryption, monitoring, vulnerability, and patch management, change and configuration management, and incident response planning.

4. *In the Cloud*

The Company has chosen to host some elements of the AMI solution in the Cloud. Portions of the DI solution are only available in the Cloud. The Company requires that vendors of cloud-hosted applications meet the same security standards required of systems that are on premises. Transfers of data to/from the Cloud elements are done via secure mechanisms.

In summary, we take our responsibility to protect the privacy and security of our customers, grid, and information systems seriously. We have based our controls on a security controls governance framework, which leverages industry best practices. We will take a defense-in-depth approach that will apply controls at many levels to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

III. DATA ACCESS PLANS AND POLICIES

This section summarizes our data access, privacy, and governance framework. We discuss the ways that we intend to share data from our grid modernization investments with customers in *Appendix B2: Customer Strategy and Roadmap*, and how we expect grid-facing data to benefit customers above and in *Appendix B1: Grid Modernization Plan*.

Our Customer Data and Information Strategy enables the framework for maintaining the integrity and security of our data and information assets throughout its lifecycle. This strategy encompasses the creation, storage, usage, sharing, and disposal phases of data assets. The strategy also ensures Xcel Energy data and information provides business value, minimizes risk, and complies with legal and regulatory requirements.

A. Culture

Xcel Energy's data is managed as an asset of the business. We leverage data to drive more understanding within the business about how data can be employed to improve operational performance, evaluate industry options, and help customers make better decisions. We have robust data privacy and security standards for all data that varies based on the type of data. Our customer strategy is informed by these standards, and as new products, services, and experiences are identified they will comply with these standards. At this time, the expectation is that any customer-specific data derived from AGIS will be treated similar to the way customer-specific data is treated today. The primary difference in the data AGIS will capture is expected to be the granularity of the data – i.e., today's monthly consumption compared to the 5- and 15-minute interval data from AMI.

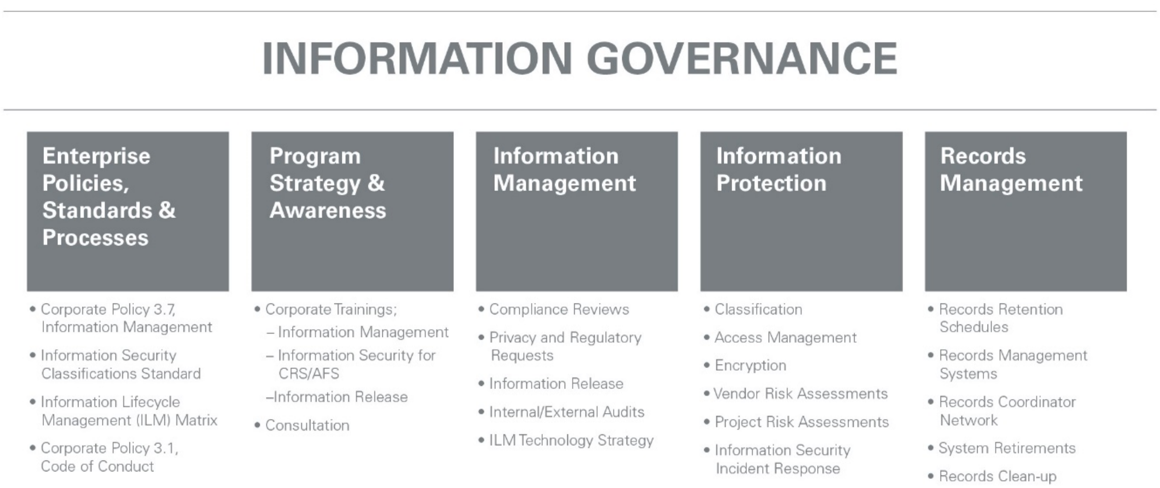
Everyone who works for Xcel Energy understands their responsibilities for maintaining the integrity and quality of our data assets, complying with data requirements, and keeping the data safe and secure. To ensure that all employees understand the criticality and responsibility of securing data, all employees are required to complete information management training annually.

B. Information Governance Framework

Xcel Energy's Enterprise Security and Emergency Management (ESEM) function oversees and provides leadership of the information governance policies, procedures, processes, and standards. This includes strategic oversight of the creation, collection, use, protection, retention, and disposal of all company information in all formats. Compliance is a corporate and individual responsibility and is monitored and evaluated through the corporate governance framework.

The key areas of Information Governance are as follows:

Figure 2: Xcel Energy Information Governance



C. Information Management and Protection

Customers trust that the information Xcel Energy creates, collects, and uses as part of its work to provide regulated utility service to customers is handled properly to avoid the potential for loss, misuse, or harm. Information Management is the policies and procedures that support data quality, data logistics and data integration covering the following lifecycle stages: (1) creation and collection; (2) use; (3) release; (4) disposition.

1. Creation and Collection

Company information is data, facts, and figures generated or received in connection with the transaction of business, and that is categorized as a Record or a Non-Record. Distinguishing between records and non-records is essential to the decision-making process regarding the use, release, and disposition of the information.

Records are any documentary material, regardless of format, that have been finalized and/or identified on a records retention schedule. Non-Records are any documentary material, regardless of format, that has not been identified as a record; non-records include copies of records.

All Company information whether it is a record or non-record is classified into four information security categories based on its value or potential risk. We describe these categories and how we classify customer information below:

- *Confidential Restricted (CRI).* CRI includes information where unauthorized disclosure (inside or outside the company), alteration or destruction has the potential for significant harm to the company, its employees, shareholders or its customers, including: damage to reputation; damage to Bulk Electric System (BES); legal, regulatory, or other sanctions. Data in this classification requires the strongest level of protection. Distribution of CRI must be limited to those with a business need to know and distribution of CRI to any third party must be approved through the approved data release process. Customer CRI includes Personally Identifiable Information (PII), such as Social Security Number (SSN), Driver's license or other government-issued identification numbers, financial account number, any individually identifiable information received directly from a financial institution, individually identifiable biometric data (including, fingerprints, voice print, retina or iris image), first name (or initial) and last name (whether in print or signature) in combination with any one of the following; Date of birth, Mother's maiden name, Digitized or other electronic signature, or DNA profile.

- *Confidential (CI).* CI includes information where unauthorized disclosure (inside or outside the company), alteration or destruction has the potential for harm to the company including: damage to reputation; material productivity loss; impede the organization's operations to the BES; legal, regulatory, or other sanctions. Data in this classification requires protection and may only be distributed to those with a business need to know and distribution of CI to any third party must be approved through the approved data release process. Examples of customer CI include details regarding a customer's account or other Xcel Energy-assigned numbers, energy usage, current charges, and billing records.

- *Internal (I).* Internal information includes information where unauthorized disclosure (inside or outside the company), alteration or destruction is unlikely to cause harm to the company, such as: damage to reputation; significant inconvenience or productivity loss; damage to BES; legal, regulatory, or other sanctions. Data in this classification may not be shared outside the company without prior approval from the information owner. Customer internal information includes aggregated customer energy usage data (CEUD) aggregated to the 15/15 threshold or whole building CEUD aggregated to the 4/50 threshold.

- *Unsecured (U)*. Information that may or must be available to the public. Unsecured information includes Xcel Energy's website, and the following documents once published and made available to the general public: SEC filings and FERC filings, brochures, advertisements, press releases, annual reports, billboard advertising, current billing rates. In terms of customer information, once aggregated CEUD is authorized, it becomes unsecured information (example: the Community Energy Reports on the xcelenergy.com website).

2. Use

Our Privacy Policy outlines the ways that we may use the information we obtain about our customers, as follows:[2]

- Assist in establishing an account with Xcel Energy
- Provide, bill, and collect for Xcel Energy products and services
- Communicate with customers, respond to their questions and comments, and provide customer support
- Provide customers access to their information via the My Account site
- Administer customers participation in events, programs, surveys, and other offers and promotions
- Operate, evaluate, and improve Xcel Energy's business and the regulated products and services we offer (including developing new products and services, analyzing our products and services, optimizing customer experience on websites, managing our energy distribution system and our communications, reducing costs and improving service accuracy and reliability, and performing accounting, auditing and other internal functions)
- Create aggregated or de-identified energy usage data
- Protect against and prevent fraud, unauthorized transactions, claims and other liabilities, including past due accounts
- Manage risk exposure

[2] The Xcel Energy Privacy Policy in its entirety can be found at: https://www.xcelenergy.com/staticfiles/xe/Admin/Xcel%20Online%20Privacy%20Policy.pdf

- Comply with applicable legal and regulatory requirements

Internally, we base our use parameters on the information security category assigned to the type of information. Employee access to customer CRI or CI is limited to only those employees and contract workers with approved access to our customer system (Customer Resource System or CRS).

Employees with access to customer CRI and/or CI are prohibited from accessing viewing for a non-business reason; accessing or transferring it for personal gain, advantage, or any other personal reason; giving access to or transferring it without first obtaining appropriate approvals; downloading, uploading, or saving it on a personally owned computing device; and accessing it from a public computer.

3. Release

Xcel Energy will only release customer CRI pertaining to an individual to that individual once the identity of the individual has been validated. We will release customer CI to the customer of record upon validating the customer's identity, or to a third party upon receiving a documented and verified consent from the customer of record. We may also disclose customer CI as required or permitted by law or applicable regulations, including to a federal, state, or local governmental agency with the power to compel such disclosure, or in response to a subpoena or court order.

We also release customer information to our contracted agents, when it is necessary for our agent to perform the service(s) specified in an Agreement.[3] All of our contracted agents go through a security vendor risk assessment (SVRA) screening process intended to provide transparency into security-related risk(s) that could potentially be introduced to Xcel Energy as a direct result of utilizing a third-party vendor's product, service, application, etc. All newly proposed vendor arrangements are subject to the (S)VRA process before a contract is signed. Suppliers are assessed by multiple ESEM teams (Security Risk Management, Physical Security, Enterprise Resilience, and Information Governance) to ensure security risk is addressed holistically. We prohibit these service providers from using or disclosing the information we provide them, except as necessary to perform specific services on our behalf or to comply with legal requirements.

For information about the Company's policies, practices, and protocols regarding the release of customer data to customers or third-parties upon request the request of a

[3] Contracted Agents are entities with whom we have a contractual relationship to support our provision of regulated utility service, or that directly provide regulated utility service to our customers on our behalf.

customer, please see our most recent Annual Report of customer data release practices.[4]

4. Disposition

The disposition phase of the information management lifecycle consists of disposal requirements as defined in a records retention schedule. Customer account and billing information, and data from our meters are retained for six years.

[4] *See* Xcel Energy Compliance Filing-Annual Report in Docket Nos. E,G002/M-12-1344 and E,G999/M-19-505 (March 1, 2021) at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={70C4EE77-0000-CA17-B20E-E090C12081BB}&documentTitle=20213-171425-01. Last accessed: October 15, 2021.

APPENDIX B4: EXISTING AND POTENTIAL NEW GRID MODERNIZATION PILOTS

In this section, we discuss the status of existing grid modernization pilot projects and potential new pilot programs.

IDP Requirement 3.D.2 requires the Company to provide:

> [the] …*status of any existing pilots or potential for new opportunities for grid modernization pilots.*

I. EXISTING PILOTS

A. Time of Use Rate Pilot

As discussed in previous IDPs, the Commission certified and approved a residential TOU rate pilot that involves two-way communication field area network (FAN) infrastructure and advanced metering infrastructure (AMI).[1] The pilot was initially scheduled to start in April 2020. However, due to the COVID-19 Pandemic, the formal launch of the pilot was delayed until November 2020. The Pilot will run until October 2022.

As a part of the pilot, selected residential customers have been switched to a rate design with variable pricing based on the time of day that energy is used. As a part of the pilot we have provided participants with new metering technology, increased energy usage information, education, and support. The pilot is designed to encourage shifting energy usage to daily periods when system load conditions are normally lower. Strategies that shift load away from peak times may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

For the pilot, we deployed advanced meters to approximately 17,000 residential customers. The customers are spread between two geographic locations, customers served out of the Hiawatha West/Midtown substation in Minneapolis, and the Westgate substation in Eden Prairie and surrounding communities. About 9,400 of the customers were enrolled in the new rate structure,[2] while about 7,200 are included in a control group. The new rate structure is designed with pricing for three time periods corresponding to our system's profile at on-peak, mid-peak, and off-peak times.

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[1] *See* Docket Nos. E002/M-17-776 and E002/M-17-775.

[2] About 200 customers have subsequently opted out of the rate structure since the pilot has launched.

The pilot was developed with the engagement of stakeholders and with the benefit of learnings from our pilot in our Colorado service territory. During the pilot we are studying the impact of rigorously designed price signals and technology-enabled data on customer usage patterns for a subset of customers. We intend to operate the pilot for two years and will share learnings about the effectiveness of these techniques to generate peak demand savings in a mid-point progress report[3] and a final pilot report.[4] We are exploring the performance of the technology in use during the pilot, the impact of the price signals, and the effectiveness of customer engagement strategies, and will use the pilot experience to inform future consideration of a broader TOU rate deployment in Minnesota.

B. Financial Recovery and Load Flexibility Proposals

The Company filed a Load Flexibility proposal on February 1, 2021,[5] which included requests for approval of an EV optimization pilot and a school bus vehicle-to-grid demonstration. The Load Flexibility proposal is also currently pending before the Commission. The EV proposals in the Financial Recovery and Load Flexibility petitions are summarized below.

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

Public Fast Charging Network Program. In addition to the work under our approved Public Charging Pilot described above, the Company proposes to build, own, and operate a network of about 20 direct-current fast charging (DCFC) stations. Under this proposal, stations would be targeted to parts of our service territory that are currently underserved by existing fast charging offerings. This proposal is intended to start helping address the current public charging infrastructure gap in our service

[3] To be filed in February 2022.
[4] To be filed about three months after pilot is complete.
[5] Docket No. E002/M-21-101

territory (including in rural areas), provide access to charging for those who cannot charge at home or at their business, and enable intra-community transportation.

EV Optimization Pilot. This pilot will study the management of the grid impacts of electric vehicles by working with customers to provide schedule options for their daily EV charging, with participating customers receiving a bill credit. The schedule options ensure charging occurs outside the Company's system peak and are designed to stagger charging times to avoid demand spikes during the off-peak period.

School Bus Vehicle-to-Grid (V2G) Demonstration. This demonstration project will study the value of V2G applications for the distribution grid. The project is designed to allow the Company to dispatch bus batteries during summer system peaks, for use during critical times or when a strain on the power grid is expected. Various applications will be tested and impacts to the distribution system will be measured and verified. The project will also present opportunities to test renewables integration by charging batteries during periods of excess wind or excess solar generation on the grid.

C. Residential Battery Demand Response Pilot

The Residential Battery Demand Response Pilot (Battery Connect) launched for PSCo in the first quarter of 2021. The pilot is currently testing how batteries can provide energy during peak hours, perform solar time shifting, and absorb energy during hours of low cost production as part of PSCo's 2019/2020 Demand Side Management Plan. The Company is currently contracted with Tesla and SolarEdge for managing the testing of residential batteries installed in customer homes. Participating customers currently receive $1,250 upfront and we are looking into the addition of monthly performance incentives as we expand the pilot. For more information, see https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates & Regulations/Regulatory Filings/DSM-Plan.pdf (*Note*: Pilot description starts at page 321 of the PDF).

II. POTENTIAL NEW PILOTS

With regard to new opportunities for grid modernization pilots, we are currently evaluating the following two time of use rate structure pilots for general service customers in Minnesota and will bring them forward to the Commission for approval as necessary in early 2022.

A. Energy Rate and Demand Charge Components

The first pilot we are exploring consists of two time-varying rate components – an energy rate component and a demand charge component. Each of the two components have charges that vary based on three time periods. The Demand charge is further differentiated by time of year.

B. Volumetric Pricing plus Energy and Demand in One kWh Charge

The second pilot will feature volumetric pricing that combines energy and demand charges into one per kWh charge. The charge will vary by time of day, using three time periods. This rate will also feature a critical peak pricing component, that allows the Company to call events for up to 75 hours per year with a much higher per kWh charge during these events.

Aspects of the implementation of these pilots are currently in development. We expect to submit our pilot proposal in early 2022, and that the pilots would launch later in the year. We expect these two pilots to inform a new, permanent general service TOU rate tariff that will be proposed in a future filing after the pilots are completed. We expect a permanent rate, if approved, would be launched after AMI is fully deployed and operational.

Finally, we note that in our 2019 IDP, we outlined several other pilots that have since concluded. These included a Colorado pilot called Charging Perks, the Pena Station Project, and the Stapleton Project. We provided compliance updates on these projects as required by the Commission's Orders in past IDPs until they concluded. We also previously outlined several electric vehicle pilots and programs that continue to be underway in Minnesota and other Xcel Energy jurisdictions.

APPENDIX C: GRID MODERNIZATION ACTION PLANS

In this section, we provide a 5-year action plan as part of a long-term plan for the distribution system, as required by filing requirement 3.D.2. by the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251.[1]

> *Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:*
>
> - *Overview of investment plan: scope, timing, and cost recovery mechanism*
> - *Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.*
> - *Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.*
> - *System interoperability and communications strategy*
> - *Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)*
> - *Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)*
> - *Customer anticipated benefit and cost*
> - *Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)*
> - *Plans to manage rate or bill impacts, if any*
> - *Impacts to net present value of system costs (in NPV RR/MWh or MW)*

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[1] As modified by Ordering Point Nos. 3 and 4 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, which modified the cost-benefit analysis requirement in requirement 3.D.2 and merged the separate action plan required by IDP requirement 3.D.1 into 3.D.2, respectively.

- *For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.*
- *Status of any existing pilots or potential for new opportunities for grid modernization pilots.*

We summarize our 5-year and long-term action plans for distribution system developments and investments in grid modernization and associated customer impacts below. However, rather than attempt to summarize our fulfillment of each of the above requirements in this section, we provide this information in our Compliance Matrix provided as Attachment B.

I. NEAR-TERM ACTION PLAN

The first five years of our action plan will be focused on providing customers with safe, reliable electric service and continuing to make investments to modernize the distribution grid with foundational capabilities including AMI, FAN, ADMS, and FLISR, which we have discussed in depth in prior IDPs. We will also be further integrating our new LoadSEER system planning tool toward advancing our forecasting and other planning capabilities.

In addition to these ongoing efforts, we are also proposing new initiatives and changes to current efforts, as summarized below:

- Certification of Distributed Intelligence (DI). As discussed in Appendix G, the Company is making, and expects to complete by the end of 2021, foundational software architecture and infrastructure/hardware investments in the DI portion of our AMI meters. We are estimating customer benefits from initial use cases will begin to accrue in 2022 as the first DI-capable meters are deployed.
- Certification of the Resilient Minneapolis Project. As discussed in Appendix H, if certified we will begin implementation of this project in summer 2022, including issuing RFP(s) to select battery vendors; signing vendor contracts; preparing detailed engineering designs to conduct the necessary distribution system work integrating solar, batteries, and microgrid controls; conduct further work with our partners on rooftop solar financing, incentives and installation; install the technologies and target project commissioning by summer 2023.

- As discussed in *Appendix F: Non-Wires Alternatives Analysis*, we propose changes to our NWA analysis based on changes in the industry and feedback from stakeholders. We intend to use this new approach with our 2022 analysis, subject to feedback from stakeholders and the Commission.

Although not specific to grid modernization, we also discuss other near-term focus areas and priorities in *Appendix D: Distribution Financial Framework and Information* and *Appendix A2: Standards, Asset Health, and Reliability Management*, where we discuss the need and our plans to invest in our system to ensure that we are able to continue to provide reliable electric service today and in the future. We outline how we intend to address aging assets, enable the clean energy transition, and modernize the grid. We are also taking near-term actions to improve the way that we are integrating Distributed Energy Resources (DER) – and longer-term, the potential implications of increased penetration levels from current programs or the recent FERC Order 2222. We discuss these in *Appendix E1: Hosting Capacity, System Interconnection, and Advanced Inverters/ IEEE 1547*.

In the balance of this Appendix, we summarize near-term actions by subject, where we intend or expect to take specific actions related to grid modernization. We also use this section to comply with the portions of IDP Requirement D.2 that we have not yet addressed elsewhere in this IDP.

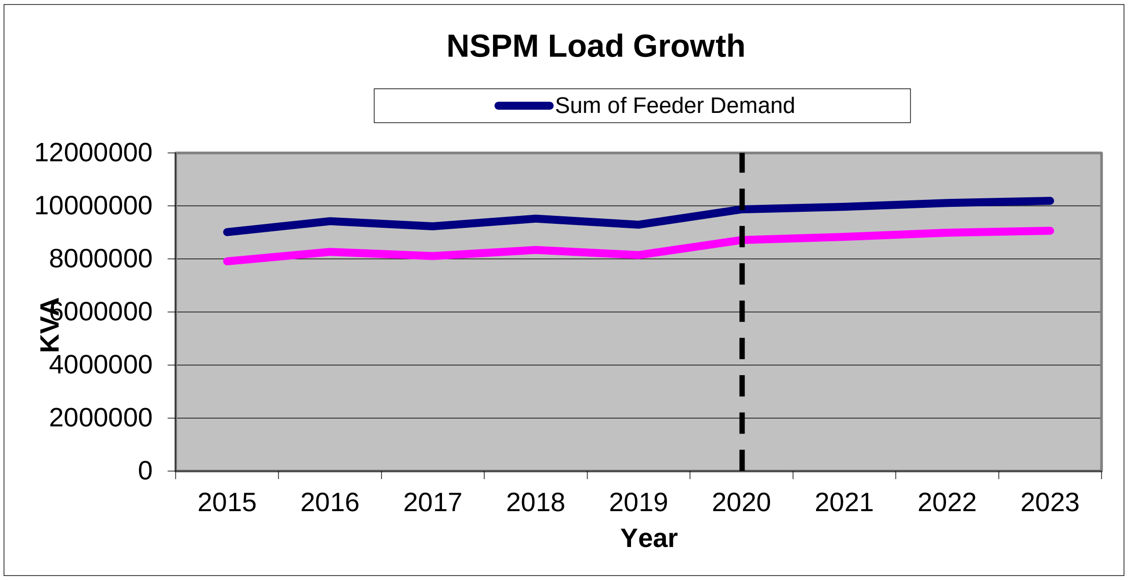
A. Load Growth Assumptions

IDP Requirement D.2 requires, in part:

> *The 5-year action plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years…*

Figure 1 below provides the load growth assumption stemming from our Fall 2020 system planning analysis, as described in detail in *Appendix A1: System Planning*.

Figure 1: Distribution System Planning Load Growth Assumptions NSPM Electric Jurisdiction (Fall 2020 Planning Analysis)



We additionally provide load growth assumptions for smaller portions of the NSPM geography in Minnesota that stemmed from this same analysis as Attachment F to this IDP. Please also see the capital projects list for the current 5-year budget cycle sorted into the IDP financial categories, provided as Attachment H.

B. Grid Modernization Plan

See *Appendix B1: Grid Modernization* and related appendices and attachments as referenced for discussion regarding our grid modernization and related customer, data, and cost recovery plans.

1. Current Initiatives Underway

Table 1 below provides a summary of the implementation timeline for the grid modernization investments the Commission has previously certified. We also discuss cost recovery mechanisms for each of these initiatives.

Table 1: AGIS Implementation Timeline

Program	Implementation Timeline
ADMS	Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021. We are pleased to report that the system is meeting our expectations. Our operator training has been very effective; the software and hardware has been functioning as expected, as evidenced by the smooth transition to this new operating platform.
TOU Rate Pilot	Launched in November 2020 and expected to conclude in late 2022. The goals are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. This pilot will provide us with an opportunity to better understand how customer react to a four-part rate (off peak, two shoulder peaks, and an on-peak period) as well as test tools and resources that may help customers adjust their energy usage to keep their bills low and better control their energy costs. The Pilot uses AMI technology to efficiently monitor energy usage and allows us to provide interval data to customers to help them better understand their energy usage as well as effectively bill the multi-part rate.
AMI	Meter deployment scheduled for 2022-2024
FAN	The implementation of FAN is underway. We started the initial network and security design in 2020 and installed and programmed the first FAN device in May 2021 and will continue installing FAN devices through 2024. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed.
LoadSEER	Our Advanced Planning Tool, Integral Analytics LoadSEER, was first used in Minnesota in September of 2020 and has been the primary tool for load forecasting in distribution planning since then. Our main focus at present is on demonstrating core forecasting functionality first before utilizing more advanced features over time.
FLISR	Installation for FLSIR devices (reclosers, switches, and substation relays) began in 2021 on select feeders.

In terms of cost recovery for these initiatives, we have started to recover the costs of ADMS through the TCR Rider and will be proposing to recover our first sets of costs (through 2022) associated with other certified grid modernization initiatives in our upcoming TCR Rider Petition, which we expect to submit in November 2021. These include the Time of Use (TOU) Rate Pilot, AMI, FAN, and LoadSEER. With respect to the IDP requirement to discuss plans to manage rate or bill impacts for grid modernization investments, if any, we outlined the estimated rate impacts of AMI and FAN in our 2019 certification request and will include an updated cost-benefit analysis (CBA) and a specific rate proposal for all of the investments included in the TCR petition, and we discuss rate impacts for DI and RMP in Appendices G and H. In our multi-year rate plan (MYRP) rate case we submitted October 25, 2021, we are proposing to recover the costs associated with our implementation of Fault Location

Isolation and Service Restoration (FLISR), which is currently planned to be deployed from 2021-2027.

Finally, we note, related to our implementation of AMI, we also intend to submit a filing regarding our phased plans to enable the remote connect and disconnect capabilities of the AMI meters in early 2022. We outlined our phased plan to stakeholders in a December 2020 workshop and our 2021 IDP stakeholder workshop in September 2021. We are planning to preview our plans in more detail with key stakeholders in Q4 2021, to gather feedback that we will use to further inform and shape the petition that we submit in early 2022.

2. Proposed Near-Term Grid Modernization Initiatives

In this IDP, we propose certification of two grid modernization initiatives under Minn. Stat. § 216B.2425 for: (1) Distributed Intelligence (DI), and (2) the Resilient Minneapolis Project (RMP). If certified by the Commission, we intend to seek cost recovery for them through a subsequent TCR Rider request. See Appendices G and H, respectively, for detailed discussion about these initiatives including their objectives, costs, functionality, and utility and customer benefits, implementation plans, and the considerations involved in proposing these near-term investments. We also provide a specific cost-benefit analysis for each of these certification proposals, as discussed in their respective Appendices.

We note that we also discuss DI as part of our Customer Strategy and Roadmap in Appendix B2 and from a grid-facing perspective in *Appendix B3: Operational and Planning Data Management, Data Security, and Data Access Plans and Policies*, and provide a rate impact analysis for DI in *Appendix G: Distribution Intelligence Certification Request*. The Company's proposed FLISR initiative is addressed as part of our Grid Modernization plan in Appendix B1, and other details and compliance requirements associated with cost recovery are addressed in the MYRP rate case submitted October 25, 2022 in Docket No. E002/GR-21-630.

Finally, while we have not incorporated our anticipated Distributed Energy Resource Management System (DERMS) into a specific timeline or proposal, we discuss it and our awareness of the need to develop many or most of these capabilities in the near future in Appendix B1: Grid Modernization. We are currently in the initial stages of ideation, but see a DERMS playing a key role in a future of increasing DER and FERC Order 2222 – both also discussed in this IDP.

C. Impacts to Net Present Value of System Costs

IDP Requirement 3.D.2 requires the Company to provide

> …*Impacts to net present value of system costs (in NPV RR/MWh or MW)*

See *Attachment _: Distribution Function NPV 2021*

D. Demand Side Management

The five-year action plan for Demand Side Management, which includes both energy efficiency and demand response, will be largely determined through a combination of Minnesota CIP Triennial (both current and future) filings and the IRP.

1. Energy Efficiency

Currently, the Company is operating under the incremental DSM goals established by the Deputy Commissioner of the Department of Commerce in the approved 2021 – 2023 CIP Triennial Plan.[2] As outlined in the plan, the Company proposed its most significant annual electric savings goal ever filed – 2.5 percent of retail sales for a three-year period. In the currently active 2020-2034 Integrated Resource Plan (IRP) (Docket No. E002/RP-19-368), we proposed a substantial increase in energy savings over the previous 2016-2030 IRP (in Docket No. E002/RP-15-21), with an annual goal of approximately 780 GWh, resulting in a cumulative goal of 11,795 GWh of energy savings over the planning period.[3]

2. Demand Response

Demand Response (DR) will continue to be heavily influenced by our efforts to achieve the incremental 400 MW by 2023, a requirement that stemmed from our 2015 IRP in Docket No. E002/RP-15-21. In the 2020-2034 IRP, we have explained that we are seeking to leverage our existing programs that utilize traditional DR efforts that focus on shedding customer load during peak times, coupled with new and innovative approaches that will explore the concept of load flexibility; this refers to DR resources that focus on how a customer's own actions can affect reduced demand and system cost. Within the 2020-2034 IRP, we have proposed cumulative goals of

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[2] *In the Matter of Xcel Energy's 2021-2023 Conservation Improvement Program Triennial Plan,* Docket No. E,G002/CIP-20-473, Order Approving Plan with Determinations, November 25, 2020 page 75.
[3] *Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan,* Docket No. E-002/RP-19-368, filed with the Public Utilities Commission, July 1, 2019.

2,156 MW of demand savings, including the growth of our DR portfolio to over 1,500 MW by 2034.

II. LONG-TERM ACTION PLAN AND CUSTOMER IMPACTS

In this section, we address the long-term plan IDP requirements – discussing primarily the long-term trajectory of our near-term investments and providing a long-term load forecast.

IDP Requirement 3.D.3 requires the following:

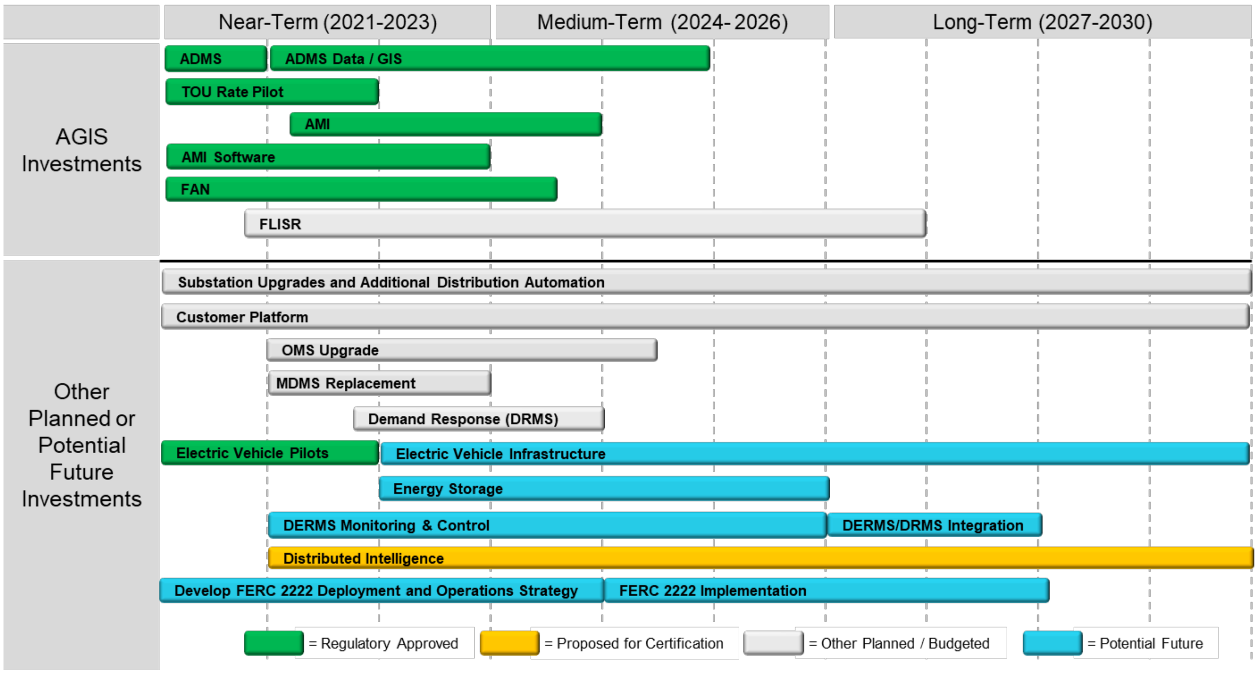
> *In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term plan discussion should address the long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.*

A. Long-Term Grid, Tools, and Capabilities Focus

As we have discussed, our long-term focus for the distribution system is to advance the grid and our capabilities by first building foundational capabilities then further leveraging that foundation with advanced capabilities. This includes enhanced distribution planning tools to advance our capabilities to bring DER into our planning – and to perform DER futures analyses, as we have discussed in this IDP.

Although also provided above in this IDP, for easy reference, we provide a 10-year view of the sequencing of planned and potential advanced grid investments in Figure 2 below.

Figure 2: Grid Modernization Initiatives – Present to 2030 View



The sequencing of initiatives aligns with the measured approach adopted by the Company that initially focuses on foundational investments, while also realizing some early capabilities and benefits for customers. This approach positions the Company to make prudent investments over time in more advanced capabilities, while maintaining flexibility to adapt to changing customer priorities, trends in DER penetration, and future policy direction. As previously discussed, the Company has received certification approval for AMI, FAN, ADMS, LoadSEER and the TOU Pilot. Each of these investments is underway and are important steps along the grid modernization roadmap.

As we have noted in other areas of this IDP, there is an increasing need to have more DER visibility and in some cases control to maintain a secure reliable distribution system. Currently, we are examining DERMS capabilities as associated market and technology maturity and will examine how they can help support higher DER scenarios, NWA's and other distribution system needs. The company is working with organizations like Smart Energy Power Alliance (SEPA) and EPRI to understand existing technology and the value provided to utilities and its customers.

FERC Order 2222 enables aggregated DERs to participate in wholesale markets operated by RTOs/ISOs. The Company is a part of these discussions with MISO and MISO-served distribution utilities. Additional capabilities with local monitoring, market registration, or control may be needed, and the role of DERMS in meeting these needs will be studied. In summary, the Company anticipates the need for DERMS capabilities and is beginning its exploration for the best path to provide this capability and its benefits to customers.

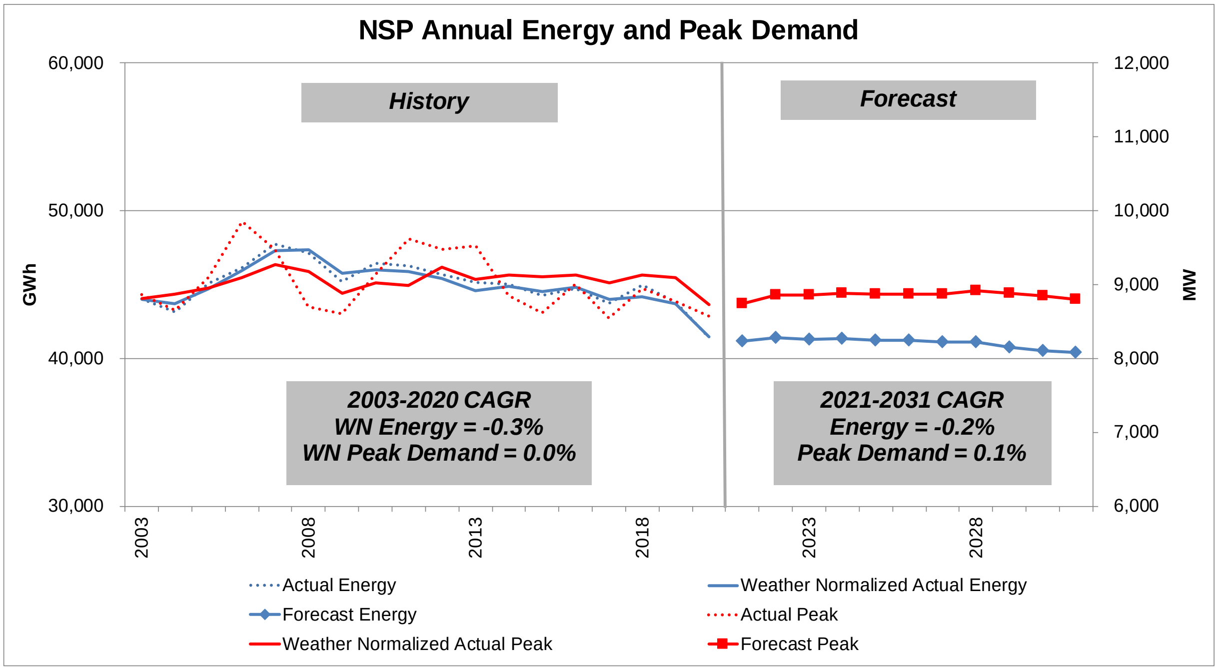
In addition to discrete grid modernizations investments, our corporate information technology infrastructure will require attention and investment on an ongoing basis to continue to meet increasingly demanding cybersecurity, data traffic, reliability, and compliance requirements along with the service expectations of our customers. Many of the investments discussed within this report involve additional data and communication needs, and a current information technology infrastructure is critical to supporting those efforts. As shown in Figure 2 as a single foundational investment, these grid modernization components are actually composed of a series of investments in equipment, data management hardware, systems integrations, and cybersecurity protections.

Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities as we have discussed.

B. Long-Term Load Growth Assumptions

As we have discussed in this IDP, distribution system planning is performed for a 5-year planning horizon. In the case of this IDP, that period is 2021-2025. In part I above, we provided our load growth assumptions that resulted from our Fall 2020 distribution planning process. For load growth assumptions beyond the distribution planning period, we provide our corporate load growth forecast, as follows:

Figure 3: NSP System Annual Energy and Peak Demand Forecast



APPENDIX D: DISTRIBUTION FINANCIAL FRAMEWORK AND INFORMATION

This Appendix discusses Xcel Energy's distribution financial information. This includes the overall budget development, as well as the Distribution organization's specific budget development processes.

I. OVERALL BUDGET DEVELOPMENT FRAMEWORK

Electric and gas utilities are long-term, capital intensive businesses. Every year, we prepare a five-year financial forecast that is used to anticipate the financial needs of each of the Xcel Energy operating utility companies, including NSPM. The five-year forecast provides the information necessary to make strategic and financial decisions to address these needs, and to develop supportable and attainable financial plans for each operating utility subsidiary and for Xcel Energy overall. Key components of the five-year financial forecast are the O&M and capital expenditure five-year budgets for each of Xcel Energy's operating utility subsidiaries, including the NSPM.

To a large extent, the O&M and capital budgeting process are the same. The capital budget process, however, requires additional steps and approvals for capital projects with expenditures over $10 million. Likewise, capital projects with expenditures over $50 million also require additional steps. In terms of review and oversight of expenditures after budgets are finalized, we conduct the same monthly review and variance analysis for both O&M and capital expenditures – and an additional comprehensive review on a quarterly basis.

II. DISTRIBUTION BUDGET FRAMEWORK

Historically, the overwhelming majority of the Distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

The Distribution business area employs a "bottom-up" approach to budgeting and planning for the future needs of the distribution system. In coordination with the corporate budget process, the Distribution business area budgets for their work by identifying the necessary investments needed over the next five years. This includes both forecasting appropriate funding for routine investments and identification of specific non-routine projects within our various capital groupings, discussed below. We utilize a comprehensive capital forecasting system to budget for and track these costs. Distribution's annual capital budget is also dependent on the Company's overall finances and other business area needs.

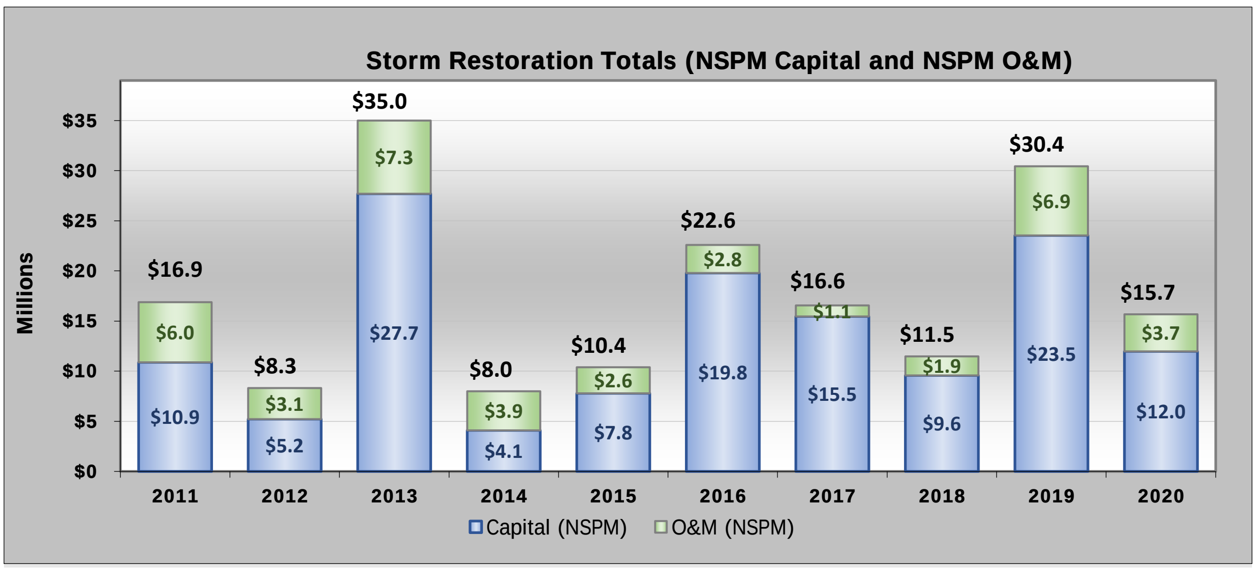
In addition, the Distribution capital budget is dependent on the state of the economy, which has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. To obtain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

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

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, as 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. For example, if we have a significant increase in required 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 that can reasonably be reduced upon short notice.

This means, should an emergency occur during the year, priorities may change in a way that then results in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. An example of this 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 shows our capital and O&M storm restoration spend for the past 10 years and depicts how this spend is uneven year-to-year due to the unpredictable nature of storms.

Figure 1: Storm Restoration Capital and O&M



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

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 also fund. Risks are potential 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. See *Appendix A1: System Planning* for more details about the planning process and Attachment D for our risk ranking methodology.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. Through our budget deployment process, we are able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Below we outline the Distribution capital and O&M budgets. While both the capital and O&M information we provide are generally for the Distribution function, as we discuss the respective sections, the capital costs are for the State of Minnesota, and the O&M information is portrayed at the NSPM operating company level and as such are not fully comparable.[1] An NSPM view of historical and budgeted O&M provides a directionally accurate view of the O&M costs for the state of Minnesota, as Minnesota represents the overwhelming majority of the NSPM operating company. Further, an NSPM operating company view also makes it possible to portray the corresponding Business Systems-related AGIS costs.

III. CAPITAL BUDGET DEVELOPMENT

Our distribution system is the portion of our electric system that is closest to our customers and consists of overhead feeder lines, poles, and underground cable that connect individual customers to the larger electric grid. Distribution also operates and maintains area substations comprised of transformers, switches, breakers, and relays that step-down the high voltage power from transmission lines to serve our customers. Each of these many assets must be maintained in good working order for our distribution system to be able to work as it is intended. The health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future. To that end, our near-term investments in our distribution system are focused on achieving three primary objectives: (1) addressing our aging assets; (2) enabling the clean energy transition; and (3) modernizing the grid.

[1] This is consistent with past IDPs. A "functional" view of a business area, in this case Distribution, are costs directly associated with that function, so will not include allocations for items such as shared services.

A. Address Aging Assets

For over 100 years, our Distribution business area has been focused on the delivery of safe and reliable electric service to our customers. Construction of electricity infrastructure in the United States began in the early 1900s and throughout the 1900s this investment was driven by new transmission technologies, central station generating plants, and growing electricity demand, especially after World War II. In the 1950s and 1960s, Xcel Energy expanded its distribution network of overhead feeder lines and added more substations to address this increase in electric demand as well as the growth and expansion of suburban communities. In the 1970s, we continued to see an increase in electrical demand due to the proliferation of central air conditioning in homes and businesses. This resulted in capacity upgrades throughout our system such as installing higher capacity wires, with more phases that were often coupled with replacement of the pole to accommodate these heavier wires. This also included installing higher capacity transformers.

Also, during the late 1960s and 1970s, Xcel Energy began to utilize underground construction with underground cables to expand its distribution network to serve new residential and commercial developments. As this history demonstrates, the primary driver of our distribution investments since the 1900s has been addressing the increasing load-serving needs of our customers by adding capacity to meet the growing electrical loads and expanding our distribution system to serve new and growing communities. These load-serving investments have often included a number of replacements of aging equipment. For instance, when more capacity was needed at a substation, we replaced a smaller undersized, and aging transformer with a larger transformer with more capacity.

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

Since the early 2000s our assets have continued to age and now many more of these assets are beyond their expected service life. To address the age and condition of these assets, Distribution will be placing greater focus on its Asset Health and Reliability budget category to ensure that we continue to meet our long-standing priority of providing safe and reliable service to our customers. The majority of the investments that Distribution will be making over the next few years will be in established programs in our Asset Health and Reliability budget category, including our pole replacement and substation renewal programs. We will also be adding a number of new programs within our Asset Health and Reliability to address specific assets that are, in some cases, having a pronounced impact on reliability. These new programs include a pole top reinforcement program, a porcelain cutout replacement program, an arrestor replacement program, and an end-of-life recloser program. We discuss these programs in *Appendix A2: Standards, Asset Health, and Reliability Management.*

These investments are necessary to meet our customers' reliability expectations, and the need for them has been further amplified by the COVID-19 pandemic that led to greater acceptance of working from home. While we have been making ongoing investments to maintain the reliability of the system by replacing assets on an as-needed basis, we have now reached the point where we need to increase the level of these investments to address a greater number assets that are at or are approaching their estimated service life. Without these needed asset replacements, the system will be at greater risk of outage events due to equipment failures. Xcel Energy is not unique in its need to address its aging distribution infrastructure. An analysis from the U.S. Energy Information Administration reported that spending on electric distribution systems by major U.S. electric utilities has risen 54 percent over the past two decades, from $31 billion to $51 billion annually.[2]

B. Enabling the Clean Energy Transition

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

Both generating DER and greater electrification of the system will require that our distribution equipment be robust enough to maintain proper voltage levels when

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

these new generation resources or load comes online. Our investments in our Asset Health and Reliability category will be essential to enabling our grid to handle these changes. For instance, replacing key assets like substation transformers and breakers better ensures that this equipment is able to handle these different power flows. We are also supporting DER through other investments like our Community Solar Garden Recloser program in 2022. This program will install electronic reclosers on both new and existing Community Solar Gardens to reduce the frequency and impact of planned outages on the generation output of these resources.

We will also be supporting the clean energy transition through investments in a number of existing EV programs as well as expanding our EV offerings. Xcel Energy has committed to working with public, private, and non-profit partners to power 1.5 million EVs across the areas served by Xcel Energy's operating companies by 2030, which is 20 percent of all vehicles and is equivalent to a 30-fold increase in electric vehicles. This increase in EVs will not only save customers fuel costs but it will also significantly reduce carbon emissions. This includes work on several pilot programs that were previously approved by the Commission, the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot,[3] as well as four new pilots and programs that are currently before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending with the Commission. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket.

C. Modernizing the Grid

Another primary area of focus for Distribution is on implementing a variety of grid modernization investments. These investments will make the grid smarter and more responsive, increase system visibility and control, and enable expanded customer options. While we have already implemented certain modernization improvements on the distribution system, we will be implementing several major investments to further modernize the grid in the near-term. For instance, in 2022, we will start our mass deployment of Advanced Metering Infrastructure (AMI) meters across our service territory. The AMI meters will provide value to our customers through the increased visibility and information that will allow for greater energy usage insights, reliability improvements, and enhanced rate and DSM offerings. AMI will also

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

provide benefits for the Company by enhancing utility planning and improved operational capabilities. We are also deploying Fault Location, Isolation, and Service Restoration (FLISR) to reduce the duration of customer outages. FLISR works by detecting faults on overhead feeders, isolating the fault, and restoring power to the unfaulted portions of the feeder. We discuss our grid modernization plans in *Appendix B1: Grid Modernization and Appendix B2: Customer Strategy and Roadmap, and AppendixB3: Operational and Planning Data Management, Data Security, and Data Access Plans and Policies.* We discuss FLISR in the MYRP rate case we submitted October 25, 2021

IV. XCEL ENERGY CAPITAL BUDGET CATEGORIES

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. The IDP requires that we report our capital expenditures in specific categories that differ somewhat from our internal categories. In this section, we outline our internal categories, then present our budgets in the IDP categories.

A. Capital Budget Categories

We outline the Xcel Energy budget categories and how they correlate to the IDP financial categories below.

1. Asset Health and Reliability (IDP Categories: Age-Related Replacements and Asset Renewal and System Expansion or Upgrades for Reliability and Power Quality)

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 useful life. This category also captures replacements due to storms and public damage.

2. AGIS (IDP Category: Grid Modernization and Pilots)

Traditionally, our investments to modernize our system were budgeted in the Asset Health category. Beginning in 2019, as we launched the AGIS initiative, we separated these investments into their own budget category. The AGIS initiative will improve power reliability, reduce power outages, integrate increasing amounts of distributed energy resources (DER) onto the grid, and empower customers to control and track their energy usage.

3. Electric Vehicle Programs (IDP Category: Gird Modernization and Pilots)

This category includes the capital costs associated with EV pilots and programs that were previously approved by the Commission – the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot.[4] Additionally, the Company has budgeted for four new EV programs that are currently pending before the Commission. The largest portion of the EV budget is related to the Company's proposed EV Purchase Rebate program, which is currently pending before the Commission. The EV Purchase Rebate program budget will ultimately reflect the Commission's decision in that docket.

4. New Business (IDP Category: New Customer Projects and New Revenue)

This work includes 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.

5. Capacity (IDP Category: System Expansion or Upgrades for Capacity)

This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system, due to new customers or existing customers increasing their load, and to continue 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 sometimes span multiple years and are necessitated by increased load from either existing or new customers.

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

6. Mandates (IDP Category: Projects related to Local (or other) Government-Requirements)

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.

7. Tools and Equipment (IDP Category: Other)

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

8. Solar (IDP Category: Non-Investment)

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

B. IDP Capital Financial Information

IDP Requirement 3.A.26[5] requires the following:

Historical distribution system spending for the past 5-years, in each category:

a. Age-Related Replacements and Asset Renewal
b. System Expansion or Upgrades for Capacity
c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects

[5] This IDP Requirement also provides that the Company may include in the IDP any 2018 or earlier data in the following rate case categories: (a) Asset Health; (b) New Business; (c) Capacity; (d) Fleet, Tools, and Equipment; and (e) Grid Modernization.

f. Projects related to local (or other) government-requirements
g. Metering
h. Other

For each category, provide a description of what items and investments are included.

1. Category Descriptions

a. Age-Related Replacements and Asset Renewal

This category includes a comprehensive suite of programs and projects aimed at replacing aging infrastructure, as generally outlined below.

Reactive Asset Health	• Pole Replacement Program: Criteria-based pole replacements • Restoration/Failure Reserves: Storm restoration, equipment failures, and reserve transformers • Routine Rebuilds/Conversions:Small rebuildor conversion projects to address reactive, in-year system issues or customer requests • Reactive Line Programs: Asset renewal programs with minimal flexibility • SE Region Reliability InitiativeReactive Discrete Projects: Discrete projects driven by internal or external customers
Proactive Asset Health	• Substation Renewal Programs: Proactive replacement of substation equipment o Transformers, Breakers, Switches, Regulators, Relays, etc. • Line Renewal Programs: Proactive replacement of line equipment/infrastructure o Network Renewal: Transformers, Protectors and Vault Tops o Line Equipment Renewal: Porcelain Cutouts, Arrestors, Reclosers, etc. o Pole Related Renewal: Pole Top Reinforcements, Pole Top Reinforcements, Pole Fire Mitigation, Multi-Feeder Pole Mitigation o High Customer Count Taps • Discrete Projects:Discrete rebuild projects targeting aging equipment or infrastructure including substation rebuilds and 4kV conversions.

b. System Expansion or Upgrades for Capacity

This category includes projects that increase the capacity of the system to adequately serve present and forecasted customer loads, as generally outlined below.

Capacity	• Discrete Projects
	  o Load Growth: Projects driven by existing or forecasted load growth in the area and risk minimization including overloads and contingencies
	  o Customer Driven: Projects driven by a new customer load or the expansion of existing load
	• Routines: Small reinforcement projects to address reactive, in-year system issues or customer requests
	• Programs
	  o Feeder Load Monitoring – Program to install SCADA on existing substations
	  o Grid Reinforcements – Program to upgrade to our distribution system to enable the system to handle increased load associated with increased electrification including electric vehicles.

c. System Expansion or Upgrades for Reliability and Power Quality

This category focuses on 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, as generally outlined below.

Reliability	• Cable Replacement: Criteria based program to replace tap and mainline cable
	• Reliability Programs: Criteria based programs aimed in improving reliability
	  o Feeder Performance Improvement Program (FPIP)
	  o Reliability Monitoring System (REMS)
	  o Viper Reclosers CSG

d. New Customer Projects and New Revenue

This category includes new overhead and underground extensions and services associated with extending service to new customers, as generally outlined below.

New Service	• Routine Extensions/Services: Small extension projects to address reactive, in-year customer requests • Discrete Projects: Larger customer driven extension projects
Streetlights	• Routine Streetlights: New streetlight installations

e. Grid Modernization and Pilot Projects

This category includes AGIS and the Electric Vehicle (EV) Program, with AGIS having started in 2018 and EV having started in 2019, as generally outlined below.

AGIS	• Advanced Grid Infrastructure & Security
EV	• Electric Vehicle Program

f. Projects Related to Local (or other) Government Requirements

This category includes projects driven by local governmental entities to accommodate public works projects such as road widening or other initiatives that require the Company to relocate its facilities in public rights-of-way, as generally outlined below.

Mandates	• Discrete Projects: Large discrete relocation projects involving the relocation of overhead and underground infrastructure including wire, cable, manholes and ductline. • Routine Relocations: Small relocation projects and service conversions to address reactive, in-year government driven projects or customer requests.

g. Metering

This category includes 'business-as-usual' meter purchases, not metering expenditures associated with our AMI plans, as generally outlined below.

Meter Purchases	• Meter Purchases: Routine meter purchases associated with base business.

h. Other

This category includes fleet, tools, communication equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets, and transformer purchases. This category also includes placeholders for new strategic programs to increase cyber security, privatize the substation communication infrastructure and add monitoring equipment to our downtown networks, as generally outlined below.

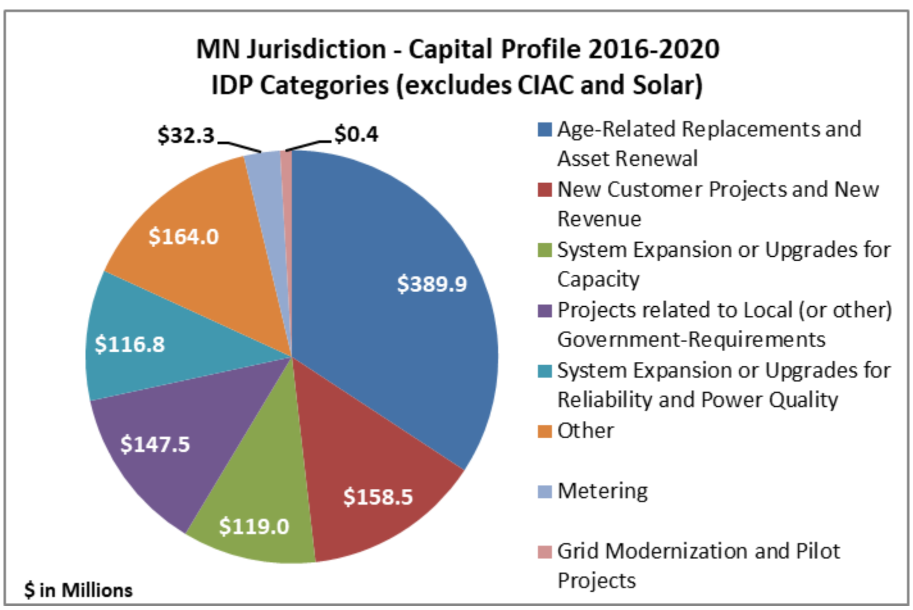
Other	• Fleet Purchases
	• Communication Equipment
	  o Discrete Projects
	  o Feeder Load Monitoring Program
	  o Network Monitoring
	• Corporate Initiatives
	  o Fiber Buildout
	  o Cyber Security
	• Tools & Equipment

Transformer Purchases	• Routine transformer purchases associated with new business (new service and capacity work) and reconstruction work (rebuilds, relocations and restoration).

2. *Historical Actual Expenditures*

Figure 2 below provides a summary of historical actual capital expenditures in the IDP categories.

Figure 2: Actual Historical Distribution Capital Profile by IDP Category
State of Minnesota – Electric 2016-2020 (Millions)



Note: Non-investment items (Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers).

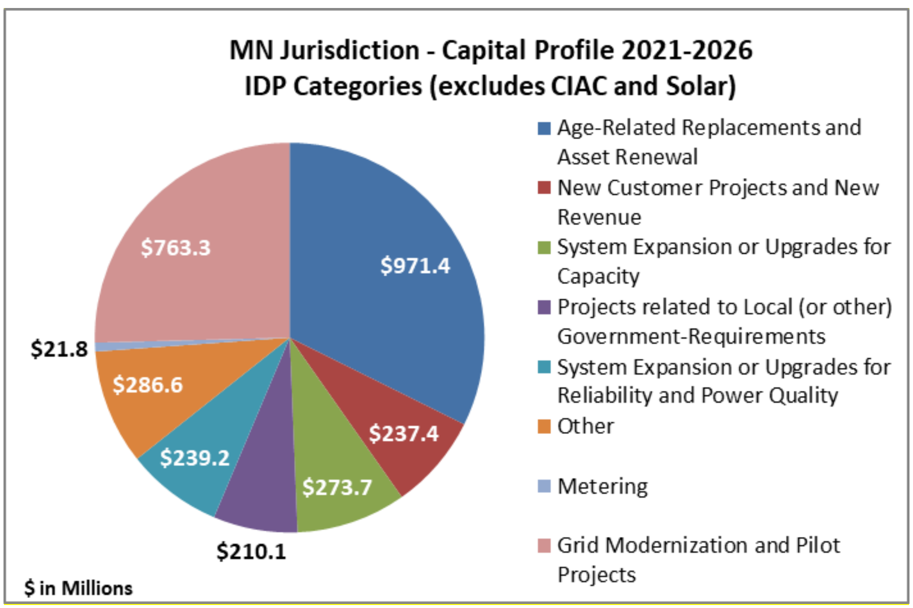
3. Budgeted Capital Expenditures

IDP Requirement 3.A.28 requires the following:

> *Projected distribution system spending for 5-years into the future for the categories listed [in 3.A.26], itemizing any non-traditional distribution projects.*

Figure 3 below provides an overview of our 5-year capital budget in the IDP categories. We also provide a corresponding Table (Table 1) of the Distribution budget information and a separate Table (Table 2) of the combined Distribution and Business Systems Grid Modernization budgeted expenditures. We clarify that we do not have any specific non-traditional distribution projects in our 5-year budget.

Figure 3: Budgeted Distribution Capital Profile by IDP Category State of Minnesota – Electric 2021-2026 (Millions)



Note: Excludes Non-investment items (Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers).

Table 1: Distribution Capital Expenditures Budget – State of Minnesota – Electric 2021-2026 (Millions)

	Bridge Year	Budget					Budget Ave
IDP Category	2021	2022	2023	2024	2025	2026	2022-2026
Age-Related Replacements and Asset Renewal	$111.3	$144.3	$167.3	$173.3	$185.5	$189.6	$172.0
New Customer Projects and New Revenue	$38.7	$37.8	$38.8	$39.7	$40.7	$41.7	$39.7
System Expansion or Upgrades for Capacity	$32.6	$38.9	$40.8	$50.9	$55.5	$55.0	$48.2
Projects related to Local (or other) Government-Requirements	$28.3	$32.4	$32.2	$36.6	$39.1	$41.5	$36.4
System Expansion or Upgrades for Reliability and Power Quality	$34.4	$46.7	$37.8	$38.9	$40.1	$41.3	$41.0
Other	$48.3	$49.2	$52.8	$51.5	$41.5	$43.3	$47.7
Metering	$6.5	$4.7	$4.1	$2.8	$1.9	$1.9	$3.1
Grid Modernization and Pilot Projects	$22.6	$186.9	$201.4	$175.7	$80.7	$96.0	$148.1
Non-Investment	($2.9)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.8)
TOTAL	$319.8	$539.3	$573.3	$567.7	$483.1	$508.5	$534.4

Notes: Grid Modernization and Pilot Projects includes AGIS and Electric Vehicle Program; Other includes Fleet, Tools, Communication Equipment, Locating, Transformer Purchases and the Advanced Planning Tool; and Non-investment includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers, annual totals will vary based on payment and project timing.

IDP Requirement 3.A.29 requires that we provide our planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historical spending – with the driver categories aligning with the IDP distribution spending categories. We provide this information as Attachments H and I to this filing.

Significant investments in the Distribution 5-year budget include our grid modernization initiatives, including the Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), and the Field Area Network (FAN) – all of which have been certified by the Commission as grid modernization investments under Minn. Stat. § 216B.2425. The Commission also certified LoadSEER as an outcome of our 2019 IDP – and we seek certification of Distributed Intelligence in this IDP. We present the budgeted amounts for these investments separately because the overall project costs involve both Distribution and Business Systems amounts.[6]

[6] The Distribution portion for each of these investments is included in the budget totals presented above.

Table 2: Grid Modernization Capital Expenditures Budget Minnesota Electric Distribution and Business Systems (Millions)

	MYRP Case Period			5-Year Period	10-Year Period
Project Component	**2022**	**2023**	**2024**	**2025-2026**	**2027-2031[7]**
ADMS	\$2.2	\$2.6	\$2.5	\$4.1	-
AMI	\$84.0	\$120.7	\$100.6	-	-
FAN	\$7.9	\$13.2	\$7.5	\$50.3	-
FLISR	\$3.9	\$8.9	\$8.9	\$25.4	\$13.1
DI[8]	\$12.2	-	-	-	-
Total	**\$110.2**	**\$145.4**	**\$119.5**	**\$79.8**	**\$13.1**

In terms of grid modernization, ADMS represents approximately \$11 million in the 2022-2026 timeframe. Our full AMI deployment is planned to begin in 2022 and continue through 2024, with projected capital costs for AMI, FAN, FLISR and DI of approximately \$368 million through 2024, and approximately \$89 million through the 2031 IDP period, for a total of approximately \$457 million.

V. O&M BUDGET DEVELOPMENT AND MANAGEMENT

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.

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

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[7] Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2022-2026.
[8] 2021 IDP certification request.

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.

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.

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.

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. The below Table highlights the variability of O&M spending *over and above* base labor and transportation (i.e., overtime, materials, contractors) for storm restoration events from 2016 to 2020.

Table 3: 2016-2020 Annual NSPM O&M Storm Restoration Expenses (Millions)

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

As shown in this table, we experienced a marked increase in O&M expenses related to storm restoration due to severe weather in 2019 and 2020, as compared to the previous three year. Thus far in 2021, we are forecasting storm O&M expenses of over $5 million – or $1.7 million higher than the average of the previous five years.

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.

A. O&M Financial Information

The O&M budget is composed of 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, which is primarily provided by contractors. Finally, it includes the fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. We therefore generally track our Distribution O&M expenditures in the following groupings: (1) Internal Labor, (2) Contract Labor, (3) Fleet, and (4) Materials.

IDP Requirement 3.A.26[9] requires the following:

> *Historical distribution system spending for the past 5-years, in each category:*
>
> *a. Age-Related Replacements and Asset Renewal*
> *b. System Expansion or Upgrades for Capacity*
> *c. System Expansion or Upgrades for Reliability and Power Quality*
> *d. New Customer Projects and New Revenue*
> *e. Grid Modernization and Pilot Projects*
> *f. Projects related to local (or other) government-requirements*
> *g. Metering*
> *h. Other*
>
> *For each category, provide a description of what items and investments are included.*

Unlike our capital budgets, where it was possible to undertake a manual process to assign projects from our internal categories to the IDP investment categories, the O&M budget does not lend itself to such a manual process. The Distribution O&M budgets are a compilation of many thousands of small expenditures, most of which are associated with operating or maintaining existing facilities. While there is often a small O&M component associated with capital projects, the amount is typically small, ranging from two to seven percent of project costs, on average, for distribution. This results in voluminous small O&M charges dispersed over many projects than cannot be aggregated in the now-required categories.

That said, we have however been able to create a partial "functional" view of both historical actuals and 5-year budgeted amounts.

B. Category Descriptions

Labor and Labor (overtime/other). This category includes the labor and labor overtime associated with Xcel Energy's employees to operate and maintain our electric distribution system. The labor pertains to the maintenance and operations of our electric distribution system. Overtime is primarily associated in response to outages, line faults, damages to our system and customer requested orders.

Contract Labor/Consulting. This category includes staff augmentation and contract outside vendors performing operations and maintenance work on our distribution

[9] This IDP Requirement also provides that the Company may include in the IDP any 2018 or earlier data in the following rate case categories: (a) Asset Health; (b) New Business; (c) Capacity; (d) Fleet, Tools, and Equipment; and (e) Grid Modernization.

systems. This also includes the delivery services for meters and transformers along with ancillary services such as barricades, flaggers, restoration, sand and gravel, etc. This is also the category where the majority of the AGIS dollars are budgeted.

Damage Prevention/Locating. This category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents.

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

Employee Expenses. This category includes the costs associated with expenditures for training, safety meetings, travel and conferences associated with our electric distribution systems.

Materials. This category represents costs associated with miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system.

Transportation. This category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) necessary to build out, operate, and maintain our electric distribution system, including annual fuel costs plus an allocation of fleet support.

Miscellaneous Other. This category represents the O&M expenditures that include office supplies, janitorial costs, dues, donations, permits, electric use costs, electric safety clothing for the crews, permits and other various items minor costs.

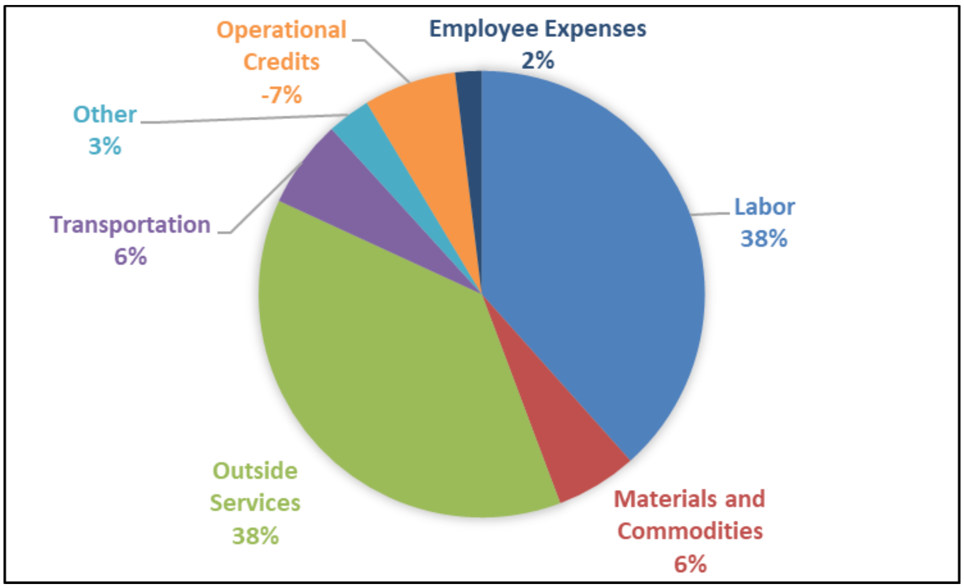
The First Set Credits. This category is the credit for the costs (labor, materials, transportation) in O&M associated with the installation of new meters and transformers.

C. Historic and Budgeted Information

Because we have budgeted for AGIS as a specific initiative, we are able to portray the associated Distribution-only O&M amounts (Table 4), and a combined Distribution and Business Systems view (Table 5).

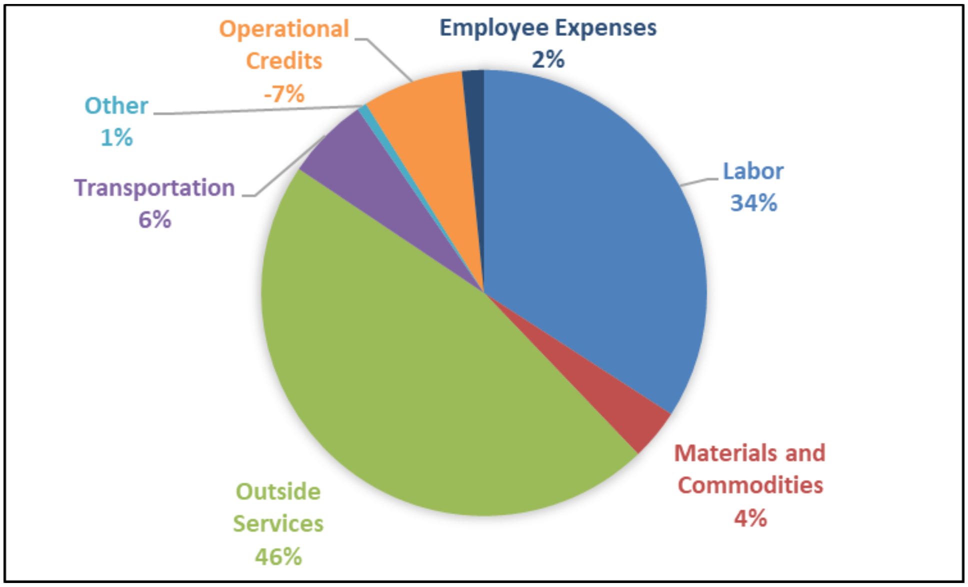
Figures 4 and 5 below provide a summary of historical actual and budgeted O&M costs in the most descriptive way that we were able to portray them given the reasons we have discussed. Following these Figures, we provide a description of the categories.

Figure 4: Actual Historical Distribution O&M Costs by Cost Element – NSPM Electric 2016-2020 (Millions)



Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $30.9M and $7.0M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Figure 5: Budgeted Distribution O&M Costs by Cost Element – NSPM Electric 2022-2026 (Millions)



Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $41.9M and $13.6M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Table 4 below provides a snapshot of our NSPM Operating Company O&M distribution budget.

Table 4: Distribution O&M Expenditures Budget – NSPM Electric 2021 – 2026 (Millions)

Expenditure Category	Bridge 2021	Budget 2022	Budget 2023	Budget 2024	Budget 2025	Budget 2026	Budget Avg 2022-2026
Labor	$43.9	$46.5	$49.0	$50.5	$53.9	$54.9	$51.0
Cont. Outside Vendor/Contract Labor	$10.5	$10.9	$11.5	$11.5	$12.4	$12.3	$11.7
Vegetation Management	$41.2	$43.4	$46.0	$46.2	$40.8	$40.7	$43.4
Damage Prevention Locates	$13.1	$14.9	$14.4	$14.6	$14.8	$15.0	$14.8
AGIS	$5.2	$6.0	$4.7	$4.0	$3.6	$3.6	$4.4
Other (Materials, Transp, First Set Credits)	$7.1	$6.0	$6.0	$6.0	$6.0	$6.0	$6.0
TOTAL	**$121.0**	**$127.7**	**$131.6**	**$132.9**	**$131.6**	**$132.6**	**$131.3**

Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the Distribution 5-year budget include the incremental programs of AGIS and Asset Health/Reliability plus increased Vegetation

Management costs to make up for some of the line clearing that was originally planned but not completed in 2020 due to COVID.

Consistent with how we present the capital budget for our grid modernization investments, we separately present the O&M to provide a complete view of both Distribution and Business Systems amounts. See Table 5 below.

Table 5: Grid Modernization O&M Expenditures Budget
Minnesota Electric Distribution and Business Systems (Millions)

	MYRP Case Period			5-Year Period	10-Year Period
Project Component	**2022**	**2023**	**2024**	**2025-2026**	**2027-2031**[10]
ADMS	$2.1	$2.0	$1.9	$4.1	$11.4
AMI[11]	$8.4	$10.2	$13.5	$26.2	$60.3
FAN	$0.4	$0.1	$0.1	$0.3	$0.7
FLISR	$0.3	$0.3	$0.3	$0.6	$1.6
Other[12]	$2.8	$9.1	$8.9	$10.0	$9.3
DI	$4.4	$7.2	$7.2	$14.4	$36.0
Total	**$18.4**	**$28.9**	**$31.9**	**$55.6**	**$119.3**

In terms of grid modernization, ADMS represents approximately $22 million of O&M through the 2031 period of this IDP. AMI, FAN, FLISR, DI and other comprise approximately $73 million of O&M through 2024, and approximately $159 million through the 2031 IDP period, for a total of approximately $232 million.

Finally, although only required for capital under IDP Requirement 3.A.29, we provide a similar trend view of our O&M costs over time, along with a brief narrative regarding year-over-year changes as Attachment J to this IDP.

[10] Period may include additional assumptions, including inflation and labor cost increases that are not part of the O&M budget in periods 2022-2026.
[11] Includes shared asset costs.
[12] Other includes: LoadSEER, project management costs, and contingency.

APPENDIX EI: HOSTING CAPACITY, SYSTEM INTERCONNECTION, AND ADVANCED INVERTERS/IEEE 1547

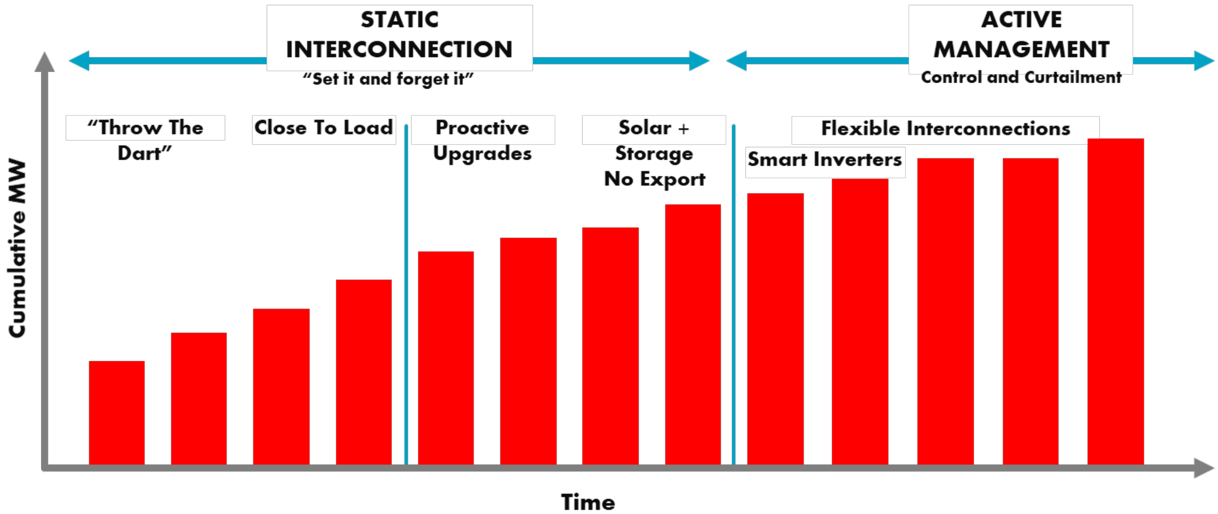
In this Appendix, we summarize our hosting capacity analysis (HCA) in the context of our overall interconnection processes and how we have evolved our HCA. We also generally discuss our interconnection processes and provide interconnection statistics. Finally, we discuss advanced inverter functionality, changes associated with IEEE 1547, and happenings at the Federal level that implicate DER and the distribution system.

I. PLANNING LANDSCAPE FOR DER

As DER penetration continues to increase on the distribution system, we recognize that we will need to continually update and evolve our interconnection processes. Historically, while DER penetration has been low, we have been able to manage DER interconnections by studying their impacts on a case-by-case basis as they work their way through our queue. This means that the earliest interconnections on a feeder generally tend to have the most favorable study results, because available capacity to host DER on the feeder is plentiful. Over time, as the amount of interconnected DER on a feeder increase, the available capacity for DER diminishes; new DER interconnections are driven toward specific locations on feeders where capacity is still available, after taking the impacts of other existing DER interconnections into consideration. Eventually, the cumulative DER interconnections on a feeder approach the feeder's capacity, and further interconnections are ultimately constrained by thermal, voltage or other physical limits of the distribution system infrastructure and the existing, previously-studied DER.

While these static interconnections are simpler to study and manage, they make incremental interconnections more difficult as feeders are increasingly saturated with DER. This ultimately means that we will need to evolve our interconnection processes to be more active in the control and management of both existing and new interconnections. Figure 1 below conceptually shows some of the stages of this evolution as DER penetration increases over time.

Figure 1: Conceptual Evolution of DER Interconnection Processes



Although we and the industry are in the early stages of this progression, we intend to study the technology requirements and the timing of their implementation that would be needed to enable the progression toward active management of DER interconnections. Some of these technologies are known and include the analysis and planning tools that are discussed in other sections of this Appendix and parts of this IDP. We are also remaining attentive to new developments across the industry to ensure that our plans are aligned with industry practices.

II. PROCESSES AND TOOLS

A. Hosting Capacity

IDP Requirement 3.B.1 requires the following:

> *Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.*

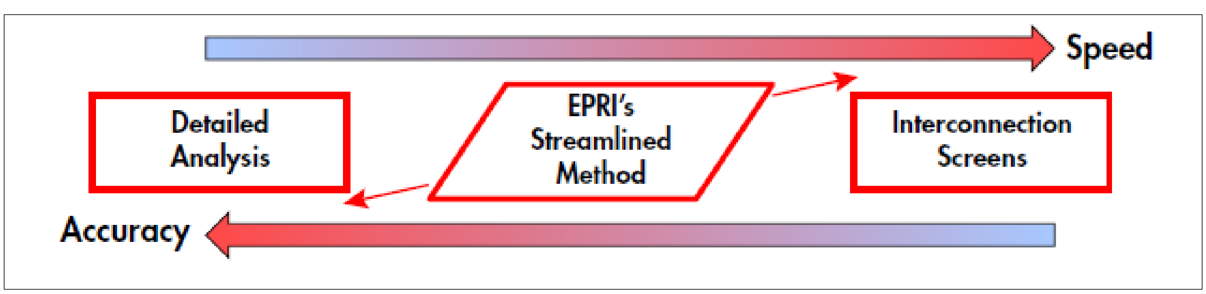
Xcel Energy recognizes hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we have conducted and submitted annual hosting capacity studies beginning in 2016 and continuing through the present. We will submit our latest hosting capacity analysis (HCA) study on November 1, 2021 concurrently with this IDP. These studies show hosting capacity results at feeder and sub-feeder level, provide an indication of distribution feeder capacity for DER, and streamline interconnection studies by helping to guide projects to places on the distribution system where there may be available capacity.

In its July 30, 2020 Order in Docket No. E002/M-19-685, the Commission directed the Company to explore several potential future Use Cases for the HCA, including various ways to integrate the HCA with the interconnection process. Our November 1, 2020 HCA Report in Docket No. E002/M-20-812 outlined how HCA information could be used in certain parts of the Minnesota DER Interconnection Process (MN DIP) and the associated investments to go in that direction. At the September 30, 2021 hearing in that docket, the Commission decided this work should continue. We look forward to working with stakeholders, the distributed generation working group (DGWG), and Commission Staff to further explore those potential futures.

1. *HCA Tools*

We continue to use the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool to automate and streamline hosting capacity analysis. The analysis is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI to screen for voltage, thermal, and protection impacts from DER. Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations to determine the minimum and maximum range of hosting capacity. The electric system's hosting capacity is mainly impacted by DER location and system characteristics.

Figure 2: Balancing Speed and Accuracy in Analysis



As indicated by Figure 1 above, EPRI's method is intended to strike a balance between speed and accuracy. While it does not replace a detailed analysis, it provides more value than a traditional interconnection screening, such as the criteria found in the FERC Small Generator Interconnection Procedure. The result is a more complete and efficient way to understand a feeder's ability to integrate new DER at multiple points on the distribution system

Our hosting analysis relies on feeder models in our Synergi Electric tool. The information for these models primarily comes from our GIS, but is supplemented with data from our annual load forecast – as well as actual customer demand and energy data. Once the models are verified, load is allocated to the feeders based on demand data and customer energy usage – and analyzed using the DRIVE tool.

Generally, it is challenging to fully predict where future DER will be located – even with an interconnection queue. For instance, a large PV interconnection may be required to make some line upgrades to accommodate the proposed generation. The line upgrades and configuration changes for that interconnection are not reflected in our GIS until the design and construction phases are complete. This is to ensure we are modeling the system as-is, in case there are delays or changes to the final construction. This means that those system modifications do not enter GIS and subsequently the feeder models in a timeframe that is well-suited for forecasting accurate hosting capacity results.

2. *We have Improved the HCA Over Time*

Through engaging with our customers and stakeholders, learning from other utilities around the country, and leveraging our partnership with EPRI, we have made notable improvements to our HCA over time. These improvements include:

- Presenting results as heat-map visual with additional data contained in pop-ups for specific locations, in addition to tabular results.
- Including existing DER in the analysis.
- Adopting a simplified methodology (IEEE-1453) to determine voltage fluctuation thresholds.
- Application of Reverse Power Flow and Unintentional Islanding thresholds to better align with the criteria we use in the interconnection process.
- Adjustment of Primary Voltage Deviation threshold to better align with how we perform interconnection studies.

- Using a methodology for large, centralized generators to more accurately reflect the characteristics of DER deployment most commonly seen in Minnesota – and associated with programs such as Solar*Rewards Community
- Refining our hosting capacity tool to include advanced inverter settings for fixed power factor (discussed in more detail in the IEEE-1547 section below).
- Including energy storage that is acting as a source of power.
- Excluding back-up DER to improve the accuracy of hosting capacity results by analyzing only those systems that are operating in grid-connected mode.
- Modifying Breaker Relay Reduction of Reach threshold to strike an appropriate balance between identifying areas where system protection impacts require closer review while not masking other limiting factors.
- Use of actual Daytime Minimum Loads where available.
- Use of actual feeder power factors on our feeders where available.
- Developing guidance on mitigations costs, including a detailed analysis for feeders with zero hosting capacity in the 2019 HCA filing.
- Indicating constrained feeders and substations in the notes field of the heat map and Feeder Tabular Results.
- Publishing all criteria violations and available hosting capacity for each feeder segment in separate Sub-Feeder Tabular Results.
- Indicting whether Voltage Supervisory Reclosing is installed on the feeder and incorporating this information into HCA results, replacing all instances where Unintentional Islanding was the limiting factor with the next applicable limit.
- Lowering the DER generation threshold that triggers a feeder model update from 500 kW to 100 kW.
- Moving to a quarterly HCA update cadence from an annual cadence.

Notably, in 2021 in response to stakeholder feedback, we began publishing quarterly updates to our hosting capacity results. Each quarterly report provides updated results for any feeders that meet one of the following criteria: 1) load change of 500 kW or greater in service or expected to be completed within one year of each analysis' data cutoff date, 2) change in aggregate DER generation 100 kW or greater in service as of each analysis' data cutoff date, 3) significant changes due to large capacity projects, feeder reconfigurations, and similar changes in service or expected to be completed within one year of each analysis' data cutoff date, and 4) each feeder is updated at least once every year. This means that over the course of one year, we will have created over 1,000 feeder models using the Synergi Electric tool, with each quarter processing approximately 25-30 percent of the total. We detail the quarterly update process in our concurrently filed HCA Report in Docket No. E002/M-21-___.[1]

We additionally note that in our 2020 HCA proceeding in Docket No. E002/M-20-812, we outlined the investments necessary to increase the cadence of the HCA to monthly, which would also enable efficiency improvements in various interconnection study processes. Based on the verbal decisions by the Commission at their September 30, 2021 hearing in our 2020 HCA proceeding, we expect to continue working with stakeholders to further shape these priorities the Commission directed the Company to explore for the HCA. We also appreciate the Commission's recognition at that hearing of the Company's efforts to improve the HCA over time.

As EPRI continues to enhance the DRIVE tool, and we continue to refine our use of DRIVE for the Minnesota HCA, we will continue to improve our HCA results. Furthermore, we anticipate our implementation of the Advanced Distribution Management System (ADMS) and the impending implementation of Advanced Metering Infrastructure (AMI) discussed elsewhere in this IDP will provide enhanced system visibility to improve the data inputs and the analytical tools to further refine the HCA output. Additionally, in the longer term, investments like more advanced control schemes coordinating action with smart inverters and utility devices will improve the hosting capacity of circuits with voltage threshold constraints.

3. HCA in Relation to Other Processes

HCA also serves as a valuable input prior to the interconnection process, helping customers or developers gather information about a location before an application is submitted. Interconnection studies are necessary to ensure the proposed generator can safely interconnect without adversely impacting electric delivery to surrounding customers and at what cost. With better data inputs and more analytical tools available to distribution engineers, we will be able to respond more efficiently to interconnection study requests and streamline the process for interconnecting customers. The interconnection process and associated studies will make use of the

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[1] At the time of filing, the Docket Number had not yet been assigned to the hosting capacity annual report. It can be found by searching eDockets for an Initial Filing submitted on behalf of Xcel Energy on November 1, 2021.

latest in technology and standards, such as IEEE-1547-2018, discussed in further detail in the section below and align with applicable regulatory guidance developed in the Interconnection and Operation of Distributed Generation Facilities proceeding (Docket No. E999/CI-16-521).

In compliance with Order Point No. 7 from the Commission's July 31, 2020 Order in our 2019 HCA Report proceeding in Docket No. E002/M-19-685, we examined the use cases, methodology and presentation of data associated with a "load HCA." This analysis could be insightful for where electric vehicle (EV) chargers, battery installations, or other forms of beneficial electrification may be able to be accommodated on the primary system. We note that a load analysis however, would only be applicable to the charging capabilities of EVs and batteries and does not include analysis surrounding discharging load-DERs.

It is also important to note that the analysis of loads on the distribution system is complex. While a specific location may be able to support a given amount of load, the individual characteristics (motor starts, charging ramp rates, power factor, etc.) of the load would require additional analysis prior to interconnection to the grid. Even with these challenges, we believe a load HCA can still serve as a starting point to guide load interconnections.

That said, our evaluation of a load HCA to-date is preliminary. The Commission's verbal decision on our 2020 HCA proceeding at their September 30, 2021 hearing required the Company to produce a load HCA November 1, 2022. To this end, we are currently developing a work plan to ensure compliance with this pending requirement. We expect that we would use the DRIVE tool to perform the analysis, much like we use DRIVE today for generation-based DER. Part of our workplan will be to revisit the assumptions and conclusions of our preliminary analysis. For example, our preliminary analysis concluded that the load HCA would likely only be relevant for load connections greater than 250kW located on distribution primary conductors. This is mainly due to a lack of detailed secondary conductor information in our systems – as we have also discussed in the HCA proceedings – as well as the manner in which DRIVE would be able to perform the analysis. Similar to the generation HCA, we would likely use the Centralized allocation method for load hosting capacity, due to the limitations of the secondary system and focus on larger single location installations. We would be able to present the data in a map format, but it would likely be most readable in a separate map from the generation HCA.

We need to further determine whether the load HCA could be performed simultaneously with the generation HCA, or whether multiple iterations of the

DRIVE analysis would need to be performed with different settings for each run. For instance, the inclusion of existing solar in the generation HCA could sway the results of the load HCA, as it does not align with current planning practices that do not include solar generation when considering large load interconnections. On the other hand, generation must also be considered to ensure that any load growth would not negatively impact the existing generation DER.

We believe a load HCA analysis could be used in several ways to assist in beneficial electrification. An interested party could use the mapped results to determine the best location for a new public/commercial EV charging station that aligns with a major road corridor or area of interest. It could also be used by a development group to target the location of a new building that they intend to heat electrically. Furthermore, combined with results from the generation HCA it could be used to highlight opportunities for large-scale batteries to integrate into the system.

As noted above, we believe mapping the load HCA outputs in a similar fashion to the generation HCA would be most beneficial. However, significant privacy and security concerns would need to be addressed with a load HCA map, as values derived in the analysis would likely be very telling of customer load information as customer counts decrease as the feeder extends out from the substation. Only showing the load hosting capacity generated by DRIVE would somewhat mitigate this concern, but loads could be deduced by knowing the capacity and comparing it to standard feeder capacities. For this reason, a public map may not be viable. We look forward to further guidance from the Commission on issues related to distribution grid and customer information security considerations in Docket Nos. E002/M-19-685 and E999/CI-20-800.

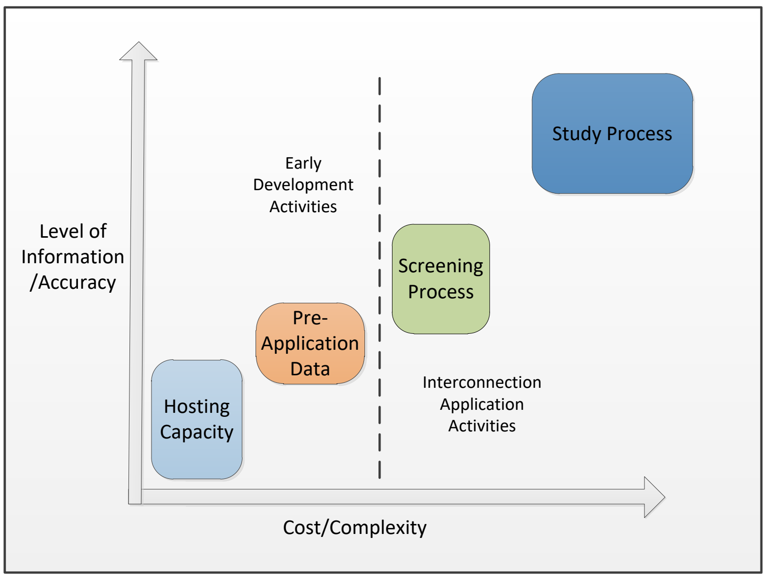
B. Interconnection Process

In this section, we generally discuss our interconnection process and respond to IDP requirement 3.B.2 regarding data sources and methodology to complete the initial review screens in the MN DIP process.

The determination of exactly where and how much DER can be added to our system is determined through the interconnection process. Our now-quarterly HCA study has the potential to streamline the interconnection process both in the short- and longer-term. Today, the hosting capacity results are available to the public and can assist developers in choosing sites; longer-term, we have outlined a path to monthly HCA updates with some integration with MN DIP screening processes. Screening is less expensive than engineering studies and typically can be completed on a shorter timeline; the HCA integrations we have outlined would shorten screening timelines.

Figure 3 below shows how the different components of our interconnection process currently works. Interconnection screen and studies require in-depth analysis that will provide a greater degree of information for the price of time and study costs. Hosting capacity and pre-application data provide information to developers that can be used to target points on the distribution system for interconnection prior to submitting an application. The screening and study processes occur after an application has been submitted and entered into engineering review.

Figure 3: Interconnection Processes



IDP Requirement 3.B.2 requires the following:

> *Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.*

MN DIP Initial Review Screens use simple analysis with assumptions or readily available data to determine if a project requires further analysis due to the potential for grid impacts. Each application's site and electrical characteristics must be compared with feeder or substation data (i.e., daytime minimum load, thermal capacity) to determine whether a project needs further analysis on voltage, thermal, or protection impacts. The specific initial review screen(s) that fail can inform more targeted analysis for the specific impact (i.e., voltage constraints, feeder loading). For example, one Initial Review Screen states that the aggregate DER shall not exceed 15 percent of the peak annual loading on a given line segment. This screen approximates when reverse power flow may occur – a condition necessitating further analysis for steady state voltage rise and voltage fluctuation. For failure of any screens, the next level of analysis is performed in the MN DIP Supplemental Review Process.

The MN DIP Initial Review screening methodology is relatively simple analysis that we implement in part through a spreadsheet tool. The initial review screens use system data and load characteristics available through a number of Company systems. We use our Geospatial Information System (GIS) to determine if the interconnection is within the Company's service area and site-specific details for secondary-connected DER. GIS also assists in determining the aggregate amount of generation on a segment of interest. Feeder maps or GIS can be used to determine the presence of a voltage regulator, which is a relevant factor in one screen. We retrieve peak load information via SCADA telemetry and reported via LoadSEER, which we also use for system planning. Fault current can be retrieved by the OMS or a spreadsheet analysis tool.

C. Company Costs and Customer Charges Associated with DER Generation Installations

The information we provide below fulfills the following IDP requirements:

IDP Requirement 3.A.15 requires the following:

> *Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).*

IDP Requirement 3.A.16 requires the following:

> *Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.).*

IDP Requirement 3.A.27 requires the following:

> *All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation).*

We calculate our actual DER costs on a project basis and perform this calculation at the time we charge this actual cost to the DER customer. This occurs after the DER is interconnected to our network. Large projects, such as community solar gardens, may straddle more than one calendar year. This means that when we calculate the costs for a given project, the calculated costs typically include costs from prior calendar years. Similarly, if a bill for a given project under construction is not issued in a given calendar year then our tracked and reported costs will not reflect these costs until we issue a bill.

Beginning on June 17, 2019, we began following the Minnesota Distribution Interconnection Process (MN DIP) as approved by the Minnesota Public Utilities Commission (Docket No. E002/M-16-521). This process requires the Company to track DER installation costs for all DER customers. We began collecting this data in 2019. We do not have a full data set to provide under these conditions for historical DER projects as it would take a significant amount of time and resources to gather this information. However, we have calculated costs at a substation and distribution level for all community solar gardens (Docket No. E002/M-13-867) and can report on the DER costs for community solar garden projects as shown in bills sent in a calendar year. In 2020, the Company billed Community Solar Garden projects $3.6 million dollars in substation costs and $17.7 million dollars in distribution costs for an approximate total of $21.4 million dollars. For onsite solar, projects typically move directly into a Facilities Study under MN DIP 3.2.2.2 and 3.4.5.2, and therefore do not receive a detailed engineering cost. In 2020, there were twenty-one projects that fell into this category over 20 kW. The total cost of these upgrades was approximately $126,000, which averages approximately $6,000 each.

In addition to this, we separately charge an engineering study fee for all DER interconnections based on the requirements of MN DIP. There are several categories of fees defined in the MN DIP including a pre-application report, review screens and engineering analysis. In 2020, these fees totaled $1,828,000. Our administrated fee for administering the analysis of DER generation applications in addition to the customer fees was approximately $469,200. Administrative fees are only collected for community solar gardens. For the sake of clarity, the information we provide for 3.A.15 is only Xcel Energy costs. Where a customer has provided the Company information on its costs to install the generation system, we report this in our annual DG interconnection filing each March 1 in the "xx-10" Docket.[2]

[2] *See*, for example, Docket No. E999/PR-20-10, available at this link: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F0808D70-0000-CD1D-8CD8-A23AFA12758C}&documentTitle=20202-160823-01

We provide further detail for regarding our other programs and the compliance filings completed yearly below.

Solar*Rewards Community – Docket No. E002/M-13-867

- Annual Report filed by April 1 every year (2020 Annual Report filed on April 1, 2021).
- *Deposits*: In 2020, we received $37 million for new projects into our deposit accounts, including any deposit that the Company was holding that the Garden Operator moved to escrow. These deposits will be refunded with interest back to the Garden Operator upon a fully executed interconnection application or if the application is withdrawn.
- *Application Fees*: The Company collected a total of $469,200 in application fees.
- *Participation Fees*: Annual participation fees were $419,500.
- *Metering Fees:* The Company administers metering charges as defined in our Section 10 Tariff based on the applicant's desire for upfront or ancillary meeting charges.

Solar*Rewards – Docket No. E002/M-13-1015

- Annual Report filed by June 1 every year (2020 Annual Report filed on May 31, 2019).
- Engineering Fees are no longer administered for Solar*Rewards projects, applicants pay all applicable fees as defined in the MN DIP.
- *Metering Fees*: The Company administers metering charges as defined in our Section 10 Tariff based on the applicant's desire for upfront or ancillary meeting charges.

III. CURRENT LEVELS OF DISTRIBUTED RESOURCES

In this section, we present current DER volumes for the DER types specified in the IDP DER definition on our Minnesota distribution system, volumes in the interconnection queue, and discuss geographic dispersion.

A. Current and In-Queue DER Volumes

In Tables 1 and 2 below, we present the DER volumes on our Minnesota distribution system in compliance with IDP Requirement Nos. 3.A.17, 18, 19, 20, 23, 24, and 25

Table 1: Distribution-Connected Distributed Energy Resources – State of Minnesota
(As of July 2021)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	142	7,762	42	1,325
RDF Projects	35	25	1	1
Wind	16	66	<1	5
Storage/Batteries[3]	<1	4	<1	18

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	811	407	555	565
Grid Scale (Aurora)	100	16	70	1

Table 2: Minnesota Distributed Energy Resources – Demand Side Management and Electric Vehicles

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency*	2,022	N/A	N/A	N/A
Demand Response	738	457,787	N/A	N/A
Electric Vehicles	N/A	7,081-8,500[4]	N/A	N/A

*Cumulative since 2005.

For reference, below are the IDP requirements fulfilled in Tables 1 and 2 above:

IDP Requirement 3.A.17 requires the following:

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[3] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.
[4] We do not have information that ties our customer accounts to electric vehicle users. *See* IDP Requirement 3.A.21 below for the sources of this range.

> *Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2021, these details were provided in Docket No. E999/PR-21-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/M-18-205) to name a few. We note that each of these reporting dockets have different reporting requirements and timing and therefore may differ slightly. Additionally, the Company provides quarterly reports regarding interconnection under the MN DIP in Docket No. E999/CI-16-521.

For purposes of this IDP requirement, we provide the information in Tables 1 and 2 above.

IDP Requirement 3.A.18 requires the following:

> *Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2021, these details were provided in Docket No. E999/PR-21-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015), Solar Energy Standard Compliance (Docket No. E002/18-0205) and the Quarterly Compliance Reporting under MN DIP (Docket No. E999/CI-16-521) to name a few.

For purposes of this IDP requirement, we provide the information in Tables 1 and 2 above.

IDP Requirement 3.A.19 requires the following:

> *Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

The Company provides information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2021, with data as of end-of-year 2021, this information was provided in Docket No. E999/PR-21-10. We clarify however, that we are not able to provide the distribution system location for current energy efficiency and DR. This is due in part to the types of DSM programs offered. For example, we do not track individual, residential customer purchases of high efficiency lighting. Also, our systems to administer DSM programs are separate from the systems that support the planning and operations of our distribution system. As we continue to evaluate enhanced distribution planning tools, we will gain a better understanding of the breadth of capabilities available and whether tracking of DSM by points on the distribution system for purposes of reporting is possible.

IDP Requirement 3.A.20 requires the following:

Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

See Tables 1 and 2 above.

IDP Requirement 3.A.23 requires the following:

Number of units and MW/MWh ratings of battery storage.

See Table 1 above. Also, we provide information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2021, with data as of end-of-year 2021, this information was provided in Docket No. E999/PR-21-10.

IDP Requirement 3.A.24 requires the following:

MWh saving and peak demand reductions from EE program spending in previous year.

In 2020 the Company's EE programs saved 646,797 MWh including a demand reduction of 165,742 kW. See Table 2 above.

IDP Requirement 3.A.25 requires the following:

Amount of controllable demand (in both MW and as a percentage of system peak).

In 2020 the Company's controllable demand was 738 MW which is 11 percent of the system load. See Table 2 above.

B. Electric Vehicles and Charging Stations in Service Area

IDP Requirement 3.A.21 requires the following:

> *Total number of electric vehicles in service territory.*

Customers are not required to inform the Company when they purchase an EV, and we do not maintain this information outside of our approved EV program participation. Therefore, we must estimate EV ownership in our service area. In our service territory, we estimate that the number of registered EVs, including various classes, is over 14,000. We describe this estimation in more detail within our 2021 Transportation Electrification Plan filed June 1, 2021 in Docket No. E999/CI-17-879.

IDP Requirement 3.A.22 requires the following:

> *Total number and capacity of public electric vehicle charging stations.*

According to the Department of Energy's Alternative Fuels Data Center, there are approximately 542 public EV charger station locations in Minnesota, with 1,226 charging ports.[5] We estimate that there are about 380 Level 2 charging stations in our service territory, with 800 charging ports. The estimated total capacity of all Level 2 public chargers in our service territory is about 4.6 MW, if all of the charging ports were in use at once. We also estimate that there are about 48 DCFC charging stations in our service territory, with 130 charging ports. The estimated total capacity of all DCFC stations in our service territory is about 4.8 MW, if all of the charging ports were in use at once. More detail about these estimates can be found in our June 1, 2021 Transportation Electrification Plan in Docket No. E999/CI-17-879. Given the relatively low load utilization of most public charging today, it is very unlikely that all, or even most, of the EV chargers will be used at one time. Additionally, the public charger installations are geographically diverse from a distribution system perspective. System impact would vary greatly based on the charging stations in use, the capacity of the charging stations, and the design of the local distribution system.

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[5] *See* public online portal at https://afdc.energy.gov/stations/states (Accessed Oct. 6, 2021).

C. Current DER Deployment – Type, Size, and Geography

IDP Requirement 3.A.31 requires the following:

> *Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).*

The DER deployment in our Minnesota system by type and size is set out above. We provide associated geographic dispersion information and the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year and as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2021, with data as of end-of-year 2020, this information was provided in Docket No. E002/PR-21-10. We also publish a Public Distributed Energy Resources Queue, which can be used to track DER installations and applications by feeder, DER type, system size and status. This information is published monthly in the Interconnection Developer Resources portion of xcelenergy.com available here: Interconnection Developer Resources | Xcel Energy>

IDP Requirement 3.A.32 requires the following:

> *Information on areas of existing or forecasted high DER penetration. Include definition and rational for what the Company considers "high" DER penetration.*

Today, we have systemwide DER forecasts and are not able to forecast DER in terms of its expected geography. It is our understanding that tools or methodologies to perform or services available for forecasts such as this are very limited at this time. That said, we are aware of highly desired locations on our system where DER projects want to connect, as those locations we maintain interconnection queues of applications per the standard MN DIP process. As we note above, we publish a monthly update of a Public Distributed Energy Resources Queue that is available in the Interconnection Developer Resources on our website.

Our new Advanced Planning Tool, LoadSEER, can take system wide DER forecasts and allocate them to various locations on the distribution system. While this provides insight into the localized impacts that may arise from forecasted adoption, it has limited ability to "steer" the adoption toward specific geographic areas of the system that might anticipate or have policy goals that call for higher adoption. However, the tool does contain location data on open DER interconnection applications from our Salesforce system, and is able to allocate corresponding levels of DER adoption toward those locations in the appropriate years in the forecast. While we do not have much insight into geographic dispersion of DER in long-term forecasts, LoadSEER is able to fill-out the early years of the forecast based on known locations of anticipated growth.

In terms of defining "high" DER penetration, we note that this is somewhat of a general term that will likely vary across utilities and the industry, and may also depend on the particular issue or scenario being discussed. We believe one way to define high DER penetration is when the connected DER output exceeds feeder load, resulting in reverse power flow. Feeders that exceed the daytime minimum load (DML) and result in reverse power flow are listed in the Public Distributed Energy Resources Queue. When backward flow occurs, mitigations become necessary.[6] Under this definition, the amount of DER considered to be "high penetration" would vary from feeder to feeder by, among other things, the type of DER, and how it operates, the feeder design, and the feeder voltage and other attributes.

Another way to define high DER penetration would be setting the high threshold where existing capacity on a particular feeder can no longer be transferred to an adjacent feeder during abnormal conditions due to the high level of DER. Yet another way to define high DER penetration would be to specify the high level at the planning limits for a feeder or substation. To maximize both operational flexibility and operations considerations as well as the interest in integrating higher levels of DER on the distribution system, the Company believes that this high level should be at the 80% of the equipment rating plus the minimum day time load. The Company has discussed this DER planning limit in the pending Docket Nos. E999/CI-16-521 and E999/CI-01-1023____.

IV. DER SCENARIO ANALYSIS

In this section, we discuss the state of DER scenario analysis and integration of distribution-connected DER in wholesale and regional markets.

A. DER Scenario Analysis

Scenario analysis helps understand future DER use cases. For example, we could analyze higher adoption scenarios or analyze how DER could impact or provide benefits to a feeder or certain area of the feeder. We have described how the new advanced planning tool will help us mature our capabilities and analysis. We believe

[6] Mitigations may be required for other conditions below this level, such as potential voltage issues or line capacity.

probabilistic analysis will be a critical aspect of incorporating DER into the distribution planning process, and that distribution planning will evolve to include:

- Historical and forecasted weather,
- Forecasted quantities and availability of DER
- Forecasted impacts of conservation and load control,
- Electric vehicle adoption,
- More granular forecasts, and hourly data rather than solely the peak load – to the extent we have sufficient SCADA capabilities,
- Storage implications, and
- Inputs from an integrated energy supply/transmission/distribution planning process.

As we have described, LoadSEER will provide us with some scenario analysis capabilities and will enable the use of multiple user-defined scenarios in developing the distribution load forecast. This will inform the distribution planning process with the insights needed to better understand the range of possible forecast outcomes and their impacts on the distribution system.

We believe that there could be some scenarios that apply to all utilities, like there are in IRPs. However, this issue is being addressed different ways nationally. The California Working Group on DER and Load Forecasting recommended different forecasting methodologies/scenarios be used between the utilities – but that common principles be followed:[7]

- Use statistically appropriate, data-driven methodologies for each DER, customer segment, and level of disaggregation.
- Develop approaches to manage uncertainty associated with granular allocation of DER.
- Periodically re-assess the modeling approach for each DER as increased adoption leads to better data.

[7] *See* http://drpwg.org/wp-content/uploads/2017/04/Joint-IOU-Draft-Assumption-and-Framework-Document.pdf

- Share best practices and leverage learning process to strive for continuous improvement both in forecasting and in using the forecasts for distribution planning.
- Integrate data from DER industry partners to enhance forecasting accuracy.

As we have discussed, the distribution planning process is rooted in specific forecasts of load densities at a feeder level – and the distribution system is our direct connection point with customers, does not have the same redundancy and back-up as exists at the transmission and energy supply level, and generally requires solutions within short timeframes. Distribution planning outcomes therefore generally require more immediate action than an IRP, for example, to ensure customer reliability. So, any changes we make in our planning processes will need to ensure our focus remains on ensuring the reliability of the system for our end use customers.

B. Community-Based Climate Goals

Order Point 4 of the Commission's July 23, 2020 Order in Docket No. E002/M-19-666 required the Company to discuss how our DER generation planning includes consideration of local community generation goals and beneficial electrification:

> *In the DER Scenario Analysis of future IDPs, Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.*

An increasing number of Minnesota communities served by Xcel Energy have adopted their own energy, climate, and broader sustainability goals. These vary by community but often include goals for increasing the community's share of renewable generation (in some cases to 100 percent), share of carbon-free generation (i.e. sum of renewable and nuclear), energy efficiency goals, and carbon or greenhouse gas reduction goals (usually a percent reduction below a specified baseline year by a specified target year; in some cases, net zero by 2050, with interim milestones). Some communities are also beginning to incorporate goals for EV adoption or other forms of beneficial electrification into their plans. Finally, some communities have adopted – in addition to a goal to use more renewable energy – a subsidiary goal that some specified amount of that renewable generation should come from local distributed resources (i.e., small-scale generation connected to the distribution system and sited within city boundaries).

As an example, the City of Minneapolis in 2013 adopted a Climate Action Plan goal to reduce overall greenhouse gas (GHG) emissions 30 percent below 2006 levels by 2025 and 80 percent below 2006 levels by 2050. Related goals in the Plan target 10 percent of electricity from "local, renewable sources" (i.e., generation sited within Minneapolis) by 2030, reducing transportation emissions, increasing recycling and composting, etc.[8] Minneapolis also aims to achieve 100 percent renewable electricity for City buildings by 2023 and 100 percent renewable electricity city-wide by 2030. The City recently released a *100% Renewable Electricity Blueprint* that includes both a 100 percent renewable city-wide goal and a subsidiary goal that 30 percent of city-wide electricity use should come from solar or other renewable sources within Minneapolis, to "create local jobs and increase our energy resilience," with the remainder coming from renewables on Xcel Energy's broader system and/or green tariff programs.[9]

Minneapolis' goals are ambitious, and other communities also have goals. The table below provides a compilation of the carbon and renewable energy goals, of Minnesota communities served by Xcel Energy as of 2019, which is the last time that we did a comprehensive update. Note the table first shows carbon reduction goals, which are generally across sectors not just for electricity, followed by renewable energy goals.

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[8] *See* Minneapolis Climate Action Plan - City of Minneapolis (minneapolismn.gov).
[9] 100 Percent Renewable Electricity - City of Minneapolis (minneapolismn.gov).

Table 3: Carbon Reduction and Renewable Energy Goals of Minnesota Cities Served by Xcel Energy (as of 2019)

Carbon Reduction Goals	
Mahtomedi	100% by 2050
Edina	30% by 2025
Minneapolis	80% by 2050
Saint Paul	100% by 2050
Eden Prairie	80% by 2050
Saint Louis Park	100% by 2040
Red Wing	25% reduction
Winona	100% by 2050
Renewable Energy Goals	
Minneapolis	100% by 2023 for municipal facilities 100% by 2030 community-wide
St Louis Park	100% by 2030
St. Cloud	80% by 2018

Another source of data is the Company's Partners in Energy program, which supports municipalities by helping them develop and implement energy plans – first assisting in developing a plan, then 18 months of assistance with plan implementation.[10] These plans often include goals to increase renewable generation and reduce GHG emissions. We provide a list of municipalities participating in the Partners in Energy program as Attachment K. The list summarizes the renewable energy/GHG, electric vehicle, and local solar/ distributed generation goals of those communities.

Finally, a recent (2020) report from the Great Plains Institute includes a list of about 40 Minnesota cities and counties who have included electric vehicle goals or policies within their comprehensive plans.[11] The majority of these are served by Xcel Energy.

[10] *See* https://mn.my.xcelenergy.com/s/partner-resources/municipalities/partners-in-energy. Last accessed October 14, 2021.
[11] *See* https://www.driveelectricmn.org/wp-content/uploads/2021/03/EV-in-Comprehensive-Plans-Guide-1.pdf at page 3. Last accessed October 14, 2021.

The Company has not to date attempted to quantify the aggregate impact of these community goals for renewable electricity, local generation, and EV adoption in terms of their potential impact on MW of incremental distributed generation connected to our system, potential generation displacing utility-scale renewables, or – in the case of EVs or other beneficial electrification – estimated MWh of additional load and MW of additional peak demand on our system. We do model scenarios for different levels of distributed generation and electrification, but have not created a scenario specifically representing goal achievement by the communities listed above. Creating such a scenario would be challenging because the communities' goals are dissimilar (different base years, target years, and target percentages) and defined in different ways (renewable electricity, carbon-free electricity, local generation). In addition, some communities are willing to largely rely on the increasing share of renewable generation on the Company's system overall while others propose to go faster, set local generation goals, or exclude some resources and include others.[12]

C. Expected DER Output and Generation Profiles

IDP Requirement 3.D.2 (v) requires the Company to provide

> …c*osts and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.).*

For more robust scenario analyses on a feeder, DER generation profiles are helpful and available. With PV systems, we can refer both to our internal generation profiles developed from load research on our customer PV systems or utilize a public tool like National Renewable Energy Laboratory's (NREL) PV Watts tool. We have also made some assumptions on EV charging usage, based on information through our residential EV service pilot program, but also compare against industry research to validate our assumptions. We additionally have several end-use load shapes available through our DSM program. These energy efficiency load shapes are generally used to determine the avoided marginal energy benefits of various DR and energy efficiency achievements.[13]

Moving forward, we expect that additional capabilities from AMI meters will be the primary source of data used for load research load profiles.

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[12] As an example, the City of Minneapolis does not count toward its 100% renewable goal all resources the State of Minnesota defines as renewable, excluding some types of hydro, waste to energy and biomass.
[13] The Company's Conservation Improvement Program (CIP) Annual Status report shows the energy efficiency and incremental demand response achievements including load shape information.

V. DER INTEGRATION CONSIDERATIONS

IDP Requirement 3.C.3 requires the following:

> *Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.*

A. Processes and Tools

Modernization of the distribution infrastructure, new planning approaches, and investment in foundational and advanced technologies are all necessary to manage increasingly complex distribution systems and to safely enable higher penetrations of DER. To achieve these levels, it will require myriad solutions and complex integrations across several information technology platforms – or more simply, it will "take a village" of solutions. Through additional monitoring and data analytics, we will have more visibility into DER and its impact on the system. Through additional control and automation, we can better manage the complexities of more dynamic grid. With these improvements we can move toward integrating higher amounts of renewable energy than today's thresholds. The industry as a whole continues to learn about technologies and best practices that can integrate more DER and these findings are often shared across the industry. Several of the tools listed below are a part of our AGIS initiative – an initiative we embarked upon with DER integration as a key driver.

*Interconnection Review.*_ Through our existing DER interconnection review process, we review each project for its impact on the grid. Each project is evaluated to determine impact on the grid during minimum load and other key periods. If system upgrades are required based on the DER impacts, the customer or developer will need to pay for the upgrades. In other cases, the customer may be required to adjust inverter settings on the DER system. As we approach higher levels, current interconnection reviews become increasingly complex and, without changes, overly burdensome and costly. We plan to continue to optimize this process and continue to examine how the situational awareness information provided by the Advanced Grid platform (specifically, more detailed information from AMI and the load flow model from ADMS) can inform our analysis and review process.

Hosting Capacity Analysis. HCA also serves as a valuable precursor to the interconnection process – helping customers or developers guide future installations. These studies that provide an indication of feeder capacity for DER will also help the Company identify trends from year-to-year. We make improvements to this analysis with each one we do and continuously strive to increase its value. For example, this year we have provided minimum daytime load information and increased the functionality of our public facing heat map. The improvements are a direct response to stakeholder feedback.

Planning Tools. As otherwise discussed in this IDP, we implemented a new advanced planning tool, LoadSEER, that will allow us to perform more robust planning and scenario analyses of DER penetration at or below the feeder level. This capability is critical for our ability to accurately and efficiently perform the analysis needed to safely achieve the listed penetration levels.

The APT will provide us with the ability to aggregate DER adoption forecasts into the distribution load forecast, and conduct scenario analysis against those forecasts. Our baseline DER adoption forecasts will be integrated directly with hourly load forecasts, where the tool uses best-fit analyses to determine potential impact of DER at the feeder level. The tool will also make it easier to develop DER scenario analysis over time that can be applied at this more granular level, and allow us to gain insight around different adoption scenarios within the tool.

In providing distribution planning with an hourly-level load forecast that includes the impact of forecasted DER adoption, distribution planning will have the data that is necessary to adequately perform risk analysis based on equipment thermal limits and inform the capital budgeting process. The advanced planning tool's assessment of DER impacts will be probabilistic in nature and thus unable to replace the need for the interconnection review process. However, it will work in conjunction with HCA to give distribution planning a better understanding of where in the distribution system, both at present and in the future, the ability to accommodate additional DER is constrained.

Monitoring and control. The Company's existing distribution operating tools are generally adequate to integrate DER at the levels listed above. But for certain situations, and for DER levels beyond the listed projections, greater monitoring and control will become essential. The ADMS system and its advanced applications are well situated to fill much of that need. And we note that a DERMS (Distributed Energy Resource Management System) may become essential as well. Along with the monitoring and control benefits of ADMS, the side-benefit of improved system data will help with the integration of DER. We have previously discussed the necessity for system data improvements for ADMS to operate properly, and note that these data improvements fill in certain gaps in our records which limit the accuracy and efficiency of our interconnection review modeling and planning analysis efforts. The investments we have made in the ADMS are timely (going into production in Q2 2020) and necessary, affording the capability for the required granular system knowledge and operation. Through our change management efforts, we have modified and implemented processes to secure these benefits including operator interactions with the systems, equipment installation and maintenance, communications and security controls, to design and data integrity.

We also note the necessity to continue deploying SCADA to the substations that are not so equipped, and thus our long-term plans call for the installation of SCADA at 3-5 substations each year. These additions improve our planning processes by shortening the time to collect and verify data. Dynamic voltage control will become more essential at higher DER levels as well. In all cases, we note that due to the quantity and dynamic nature of DER, all control systems will need to operate in automated fashion, which is part of our design.

AMI, along with our FAN are tools that are also essential to achieving higher DER levels. AMI will provide insights into DER presence, transformer loading, and voltage levels. And using the new Distributed Intelligence platform we will attain deeper insights into both our own secondary system and the operation of DER. We will alter existing processes and develop new ones to leverage that information to the benefit of our customers. A few processes that will be impacted include hosting capacity analysis, voltage monitoring, and power quality inquiry. Communication capabilities are a core enabler. We need robust, secure communication paths for all interconnected utility and connected DER – and the Company's FAN is a key enabler, providing for AMI and our distributed monitoring and control. Of course, the critical nature of such a system requires excellent monitoring and maintenance processes and tools, which we have designed into our grid modernization strategy and plan.

Additionally, we envision the integration of technologies that do not connect directly to our FAN, but through other paths. Such communication pathways must be securely integrated. One key to that effort is the development of industry standards and communication protocols, the development of which we support.

B. System Impacts and Benefits that May Arise from Increased DER Adoption

DER has the potential to both provide system benefits and negatively impact the system. Some of the potential benefits include:

- *Reduction of Peak Power Requirements.* Demand Response has been called upon for years to reduce peak, and will continue to be a valuable DER. Energy storage such as battery storage can be managed to discharge during peaks. And while DER such as EVs may in the future provide dispatchable storage, we note that it is imperative to manage charging so as to not increase system or distribution peaks.

- *Emergency source of power.* Standby generation generally benefits only one customer, and thus is generally considered to provide system benefits. But the technologies involved lend themselves to broader system benefits. Additional DER technologies such as battery storage provide new options to back-up power, and we are starting to see residential customers adopt this strategy. When PV is present, it can be combined with energy storage so that the combined system can provide power to some or all of the customer's load during an outage. These capabilities can be expanded – for example, a microgrid could provide community resilience for critical facilities.

- *Manage local capacity constraints.* Typically, the PV does not have a perfect coincidence with demand, but offsets load in the earlier hours of the peak. Also, left unmanaged, PV can create a new capacity constraint due to high solar production during low-load periods. Energy storage can help modify this pattern by charging and discharging during certain times of the day. Each feeder is somewhat unique – and we study how DER can provide benefits as part of our non-wires alternatives analysis process, which today is on a limited number of feeders; with our proposed advanced planning tool and other enhanced capabilities, we will be able to perform this type of analysis much more broadly.

- *Reduction of system power.* Customer-sited PV offsets the overall system power requirements, which is something that is considered in the Value of Solar analysis.

- *Improvements in power quality.* PV and energy storage inverters have the potential to provide improved load factor locally.

We will continue to study these benefits as we conduct our non-wires alternative processes and other DER analysis scenarios. As DER costs come down and technology software platforms mature, we expect the opportunities in this area to continue to grow.

The below table summarizes the potential negative impacts of higher penetration of distributed PV.

Table 4: Potential Distribution System Impacts from Distributed Solar PV

Distribution Impact/Constraint	Constraint Description	Cause
Primary Over-Voltage	Steady-state primary side voltage exceeds nominal voltage.	Minimum daytime loading combined with maximum solar generation leads to less net load on feeder, thus leading to higher feeder voltage.
Primary Voltage Deviation	Voltage change that happens from no DER (specifically distributed PV) to full DER in aggregate.	Potentially due to cloud cover or weather-related issues that caused DER to go from no output to full output and vice versa.
Regular Voltage Deviation	Change in bandwidth from no DER output to full DER output at a regulated node.	Potentially due to cloud cover or weather-related issues that caused DER to go from no output to full output and vice versa.
Thermal Loading Constraints for Discharging DER	Due to specific element rating (e.g., conductors).	DER deployment at low-load feeders could lead to reverse power flow, thus violating ratings on existing elements such as conductors.
Additional Element Fault Current	Deviation in feeder fault currents.	With increased installations of Distributed PV, there will also be an increase in the fault current contribution from each PV system.
Breaker Relay Reduction of Reach	Deviation in breaker fault current	Distributed PV with voltage support functions has the potential to reduce its contribution to fault currents. This will cause inadequate breaker reach that could lead to losing visibility to remote feeder faults.
Reverse Power Flow	Element minimum loading	Minimum daytime loading combined with maximum solar generation leads to generation surpassing load at the local level, which could lead to reverse power flow back to the substation.

EV Impacts – Although EV adoption is low in the NSP service area, EV charging could potentially be "clustered" around specific feeders, for example, downtown areas or specific residential neighborhoods. EV chargers would not only increase the load on a feeder, but also would change the load shape on the feeder. Various industry sources indicate that with uncoordinated or unmanaged charging, there would be an increase in EV charging during at certain times of the day which could lead to overloading issues on local distribution equipment such as transformers. There is a current EV Pilot Program in MN that monitors EV charging energy usage at participating customers' homes. These customers are also enrolled in the TOU rate program, where peak hours are from 3-8 p.m. and this incentivizes customers to charge at off-peak hours. As the pilot progresses, we will continue to analyze customer usage and evaluate whether customers respond to price signals as anticipated. This pilot has been helpful for us to understand EV charging patterns and how they could impact the distribution system.

Currently, charging times are under two hours which could lead to an opportunity to stagger the charging periods through the evening and early morning, thus preventing the second peak. This stagger charging could be performed via a rate mechanism or a price signal. There is also the option to directly control the charging behavior through the Electric Vehicle Supply Equipment (EVSE).

The Company also launched its EV Accelerate at Home program which establishes low pricing for off-peak and mid-peak hours, with a higher pricing rate for the weekday peak days between 3 and 8 p.m. Over 500 charging stations have been installed at this time. *See*: https://ev.xcelenergy.com/ev-accelerate-at-home-mn

Aggregated and widespread solutions that are able to cut across various automotive vehicles and EVSE are still emerging. More advanced managed charging techniques involved active charging and vehicle-to-grid (V2G) technology. V2G allows bi-directional power transfer from the EV to the grid and vice versa and is still an emerging technology. For example, a limited number of electric vehicles and charging stations in the market have bi-directional capabilities today

Active charging depends on utilities or third-party aggregators dispatching the charging schedules of EVs based on local grid conditions. However, this technology requires partnerships with third-party based EV aggregators (e.g., ChargePoint, eMotorWerks, etc.) to dispatch EV charging schedules as well has the availability of a robust communication network to the EV or EV charging stations. Various utilities (mainly in California) have had different managed charging EV programs ranging from passive charging techniques such as TOU rate to a more active charging techniques such as directly controlling the charging of EVs via the car chargers or through third-party aggregators.

Energy Efficiency and Demand Response – There are no negative impacts foreseen with energy efficiency and demand response initiatives. It is expected that demand response programs would be able to alleviate a portion of the system peak loads.

Distribution-Sized Energy Storage Systems – Energy storage systems are a valuable asset to grid reliability when they are deployed to do so; but today, most installations in our Minnesota service territory are driven by the customer's interest in having back-up power available. However, the amount of installations in Minnesota is still relatively low and the cost-effectiveness of front-of-the-meter utility installations depends highly on the operational and location of the energy storage systems. Long term, Company programs that better facilitate the use of energy storage to provide value to the grid should be considered.

Similar to the PV interconnection review, customer-connected energy storage systems are reviewed through our interconnection process for impacts on the system. The customer chooses how to operate these systems and as such, might not be designed explicitly to provide value to the distribution grid.

Energy storage systems are well suited for many applications, especially to aid in increasing PV hosting capacity on a distribution feeder as well as relieve local congestion issues that could potentially defer an upgrade to distribution equipment, such as an NWA application.

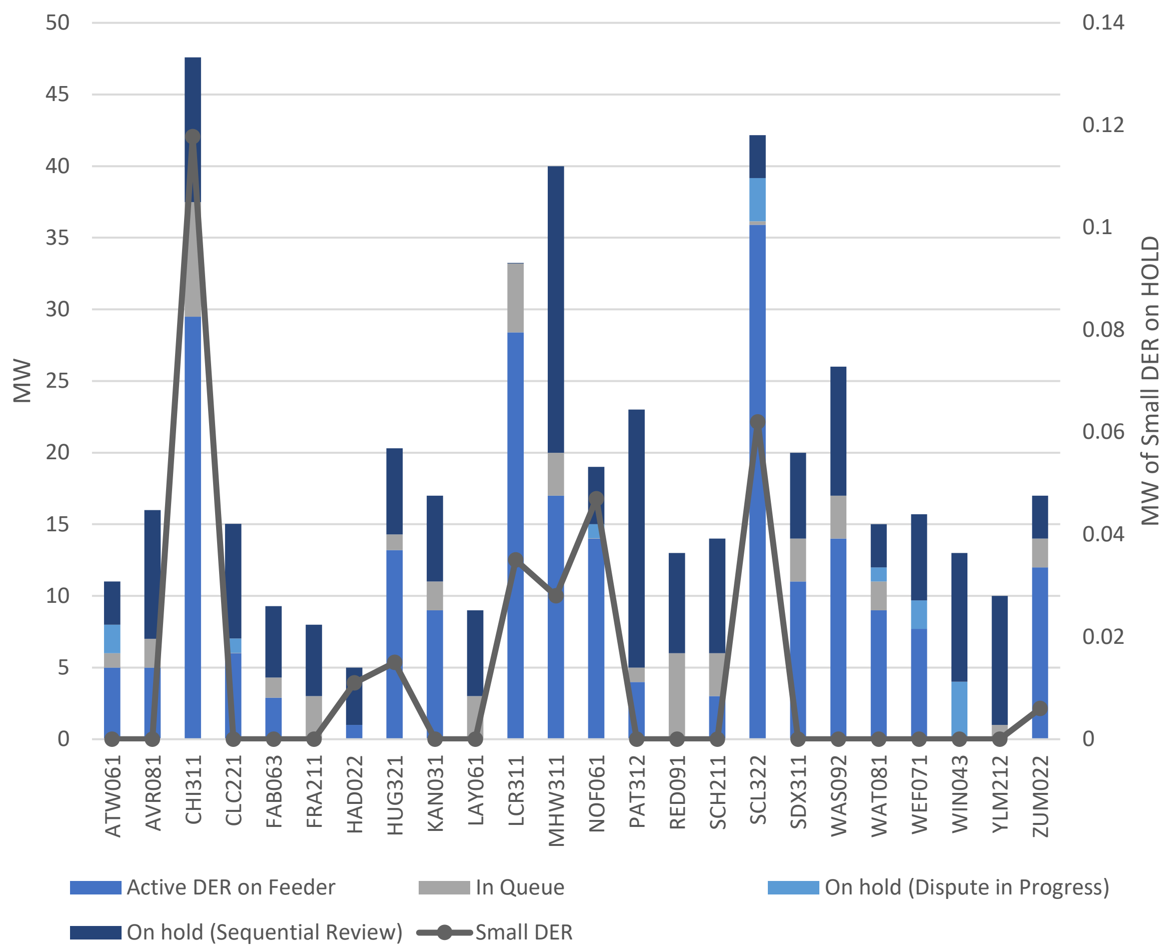
C. Potential Barriers to DER Integration

Minnesota has a cost-causation regulatory construct for DER, which requires the "cost causer" to pay the costs – shielding other customers from the costs. As such, individuals or developers proposing to interconnect DER to the system may incur costs for necessary system changes to accommodate the DER. Based on our regulatory requirements in our Section 10 tariff, the customer or developer who installs a system pays for the cost of any necessary upgrade or modification necessary for DER integration without causing impacts to the distribution system. In some cases, the developer or customer chooses not to pursue the modification and the project does not move forward due to costs. Therefore, system modifications costs are a barrier to DER integration.

Another barrier to DER integration occurs when a customer with a small DER system is assessed disproportionate amount of expenses to upgrade a neighborhood transformer because the customer installed the DER system after others in the neighborhood already had installed similar systems (and did not incur a charge to upgrade the transformer). Similarly, some customers could face disproportionate interconnection costs associated with reconductoring a feeder, if they seek to install a DER system after other larger systems (e.g., community solar gardens) have done so on the same feeder. Finally, if a large customer on a feeder that also has DER systems on it were to close or move, the drop in demand could require studies and reconductoring or other changes to avoid adverse reliability impacts for the customers connected to that feeder. This could require additional investments that take time to plan, obtain permits and build.

Since we submitted our last IDP in 2019, DER applications have become backed up in highly congested areas where the conditions are ideal to site community solar gardens. This has led to several projects being on hold, either due to the time required for projects to be reviewed sequentially or because there is currently no capacity. Below is a summary of DER capacity projects on hold, based on our October queue report:

Figure 4: Capacity Constrained Feeders (over 5 projects on hold)



We have proposed several changes in Docket Nos. E999/CI-16-521 and E999/CI-01-1023 to address the barriers described above. These proposals include but are not limited to: (1) mandatory cluster studies, which move projects through the process faster and reduce the amount of projects on hold because they projects are studied in groups, not individually. In addition, upgrade costs are spread across multiple projects; previously the first project that triggered the upgrade was assigned the entire project cost; (2) funding for up to $15,000 per project for distribution system upgrade costs for residential systems that participate in the Solar*Rewards program (this addresses some of the high residential system upgrades that may occur in high PV penetration areas; (3) implementing a policy that would reserve some of feeder and substation capacity for small DER under 40 kw; and (4) implementing DER Technical planning limits which would provide some contingency for drop in customer load as well as providing operational flexibility. Outside of that proceeding, we have already implemented a process to allow small solar projects to be studied in a parallel process so that they do not have to wait in the distribution queue. This has helped significantly, but about sixty projects in the high PV penetration areas are still in queue due to capacity constraints. This has frustrated both customers and developers; again, the capacity reservation for small systems that we have proposed would address this issue.

Longer term, we are monitoring the developments with flexible interconnection strategies.

D. Types of System Upgrades that Might be Necessary to Accommodate DER at the Listed Penetration Levels

While we are confident the proposed process changes discussed above will help support the higher levels of EV adoption noted in our forecast, there is still interest among the Company, developers and the Commission alike to find ways to integrate more DER easily. Longer term, we will be monitoring flexible interconnection capabilities and identifying associated gaps. Flexible interconnection would allow more DER to be connected without system upgrades, but the tradeoff would be that not all DER could generate or charge during peak usage periods. We also know that the implementation of FERC Order 2222 will require significant changes to our interconnection process in the later part of the decade and may also require new tools for aggregated DER registration as well as monitoring and control capabilities. We discuss Order 2222 in Section VII below.

As we have outlined in other areas of this IDP, we expect that grid modernization investments will help provide additional real-time information about our system. This information will provide feedback about how PV is affecting our operations, and may influence the assumptions we make with planning processes and interconnection reviews regarding PV integration. As we note in the smart inverters discussion within this IDP, there are also some smart inverter adjustments that could be considered.

Table 5 below shows the traditional mitigation solutions we employ for common issues that occur due to DER penetration on the system. In some instances, combinations of these mitigations need to occur in order to add additional DER.

Table 5: Potential Mitigations for Common Constraints

Category	Impacts	Mitigation
Voltage	Overvoltage	Adjust DER power factor setting, reconductor
	Voltage Deviation	Adjust DER power factor setting, reconductor
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor
Loading	Thermal Limits	Reconductor, replace equipment
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing

VI. Advanced Inverter and IEEE 1547 Considerations and Implications

In this section, we begin with general discussion regarding inverter advancements, then address IDP Requirements 3.A.7 and 3.A.33, as follows:

IDP Requirement 3.A.7

> *Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).*

IDP Requirement 3.A.33

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

Finally, we discuss our view of the impact of IEEE Std. 1547-2018 on interconnection standards/processes.

A. Inverter Advancements

Advancements in inverters and their functionality can be utilized as one measure to reduce system impacts from PV and other inverter-based DER. A revision to the industry standard governing of the interconnection of DER with electric power systems (IEEE 1547) was published in April 2018.[14] The standard provides requirements on the performance, operation, testing of the interconnection and interoperability interfaces of DER. This revision includes several new requirements that address the technical capabilities associated with smart inverters and considerations necessary for the proliferation of DER on distribution systems, such as the ability to keep DER online – 'ride-through' – during abnormal conditions, controlling real and reactive power, and regulating voltage. Furthermore, the latest revision of the standard specifies interoperability requirements, a design consideration in all our advanced grid investments.

Currently, smart inverters that are compliant with and certified to the newest IEEE 1547-2018 standards are available on a limited basis. Availability is limited to specific manufacturers and the models they have presented for certification, and is increasing in context of availability as more laboratories are certified and availability of facilities and personnel increases. The standard for test and conformance procedures necessary to certify inverters, IEEE 1547.1-2020 was completed in February 2020 and implementation of those procedures is underway. Underwriters Laboratory is in the process of updating their testing certification standards (UL 1741) to the latest information and as these updates are approved, they are distributed to the Nationally Recognized Testing Laboratories (NRTLs) for testing implementation and certification. While the timeframe for standard DERMS development activities is fluid, we anticipate compliant and certified equipment will become more widely available in year 2022. However, we note that the pandemic has created backlog issues and there are longer times required to certify the inverters.

B. Planning Considerations Associated with IEEE 1547-2018

IDP Requirement 3.A.7 requires the following:

> *Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).*

The standard IEEE 1547-2018 scope is focused on the interconnection and interoperability requirements for DER. Advanced functions offer additional capabilities from the DER side to mitigate the impacts of the interconnected DER. While modeling and simulation tools for distribution planning are evolving to include

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[14] See IEEE Publishes Standard Revision for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2018). http://standards.ieee.org/news/2018/ieee_1547-2018_standard_revision.html

these functions, the impacts, study practices, and requirements of how to implement and use these while protecting grid integrity (i.e., safety and reliability) and generation with queue priority, still need to be developed.

Distribution system planning considerations including integrating DER into capacity expansion plans and grid support functions required by IEEE 1547-2018 may provide additional tools to mitigate voltage conditions caused by DER. It is important that the standard requires DER equipment be capable of providing a range of reactive power control for the lifetime of the DER. This provides a necessary tool for mitigating future voltage issues due to changes in system configuration or other anticipated changes to grid conditions. The Company currently uses a non-unity fixed power factor approach for mitigating DER caused voltage issues and reserves a power factor range of +/- 0.9 in operating agreements. While the reactive power range in use today aligns with IEEE 1547-2018, the standard offers additional control modes. The Company is evaluating the use of other real and reactive power control modes to determine benefits, drawbacks, and most suitable use of each.

The Company is currently participating in an EPRI two-year research project with other utilities that evaluates different advanced DER functions to help identify "best fit" or "universal" DER functions to meet system objectives. EPRI is modeling multiple inverter functions and settings across a wide variety of feeder models supplied by participating utilities. While the impact of various inverter settings on a particular feeder has been studied, less is known about applying universal settings across a wide variety of feeder conditions. Expected benefits of the project include identifying feeder types were "best fit" common inverter settings would work effectively and also identify situations where more locational analysis is needed. EPRI also intends to build more capabilities into its DRIVE hosting capacity tool so that these inverter settings can be more easily modeled. The project will be completed at the end of 2022 and non-proprietary results will be made available to the public for purchase or otherwise. We expect this effort will help us continue to evaluate how advanced inverter settings can provide benefits to our customers in terms of enhanced voltage management and system reliability.

We also note that today it is standard procedure to adjust an inverter's power factor settings to address voltage conditions, which provides many benefits of the revised standard's functions. An EPRI study on a modeled radial distribution feeder with a large (almost 2 MW) solar system concludes that fixed power factor control resolves almost all voltage violations and that "modest control of reactive power can significantly reduce the voltage rise from the generator"[15] This is particularly important in Minnesota for the CSG large distributed generation systems, which are often deployed in remote areas where maintaining adequate voltage can be more challenging due to smaller conductor and a lower system strength.

We are preparing our roadmap for the deployment of smart inverters and expect to have more information to share first quarter 2022. We also anticipate using a stepped approach. Inverters will inherently have "ride-through" capabilities that in aggregate will prevent contributing to grid instability during a short-term transmission or generation event. The first step involved would be standardizing autonomous or unattended functions where appropriate, as well as harmonization with the bulk electric system various settings for protection and other considerations. Looking ahead, as we develop our modeling and simulation capabilities and phase in our investments, we will be able to evaluate more updated inverter capabilities such as the interoperability benefits described below and help and evaluate the benefits.

The interoperability capabilities required by IEEE 1547-2018 are related to exchanging information with the DER, including monitoring and control points. This aspect of the standard is the most future-leaning and is something that will be evaluated as we move forward. Using the DER interoperability interface, DER advanced functions required could be changed remotely if a communication network is established between the utility and DER system. In the more distant future, it is possible that different advanced functions are employed during different times of the day or year through a centralized control system such as DERMS. This flexibility to change between functions to better meet grid conditions at the time might offer yet another tool for mitigating DER-caused issues during distribution planning processes that involved power flow studies. As this functionality and associated products develop, it will be important to understand the costs and associated benefits to implement such a strategy.

The modeling and simulation tools needed for real time control of these systems are not in place today for the use described here. The field communication networks and backend control systems are also not in place to employ this type of use, but the Company continues to explore how the interoperability interface can best be used for integrating DER into all aspects of utility operations.

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[15] *See Voltage Regulation Support from Smart Inverters,* Electric Power Research Institute, Palo Alto, CA, Page 8 (December 2017).

C. Advanced Inverters Response to Abnormal Grid Conditions

IDP Requirement 3.A.33 requires the following:

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

Abnormal voltage and frequency issues can manifest due to distribution conditions, transmission conditions, or a combination of the two. Distribution system circumstances that can lead to abnormal conditions can include (not limited to) high DER penetration, high source impedance, and highly variable loads. These circumstances exist today and create areas within the distribution system that experience abnormal conditions. As mentioned in IDP requirement 3.A.7, there are multiple efforts being pursued to determine how advanced inverter technology could be leveraged to address these conditions.

Abnormal conditions on the transmission system can occur during scenarios such as tripping or loss of generation and transmission line faults. A driving factor for modifying national interconnection standard IEEE 1547-2018 is to require DER to provide support for wide area grid disturbances originating from the bulk electric system (Transmission and Generation). The standards apply to all DER, including PV inverter-based generation. Historically, DER was required to trip for minor grid disturbances. A large amount of DER tripping all at once has the potential to worsen the grid condition that caused the DER to trip in the first place. IEEE 1547-2018 requires the capability to ride-through grid voltage or frequency disturbances and allows a wide range of trip settings to provide Regional Transmission Operators, Independent System Operators, Transmission Operators, and Distribution Operators with options that balance possible differing technical objectives of these stakeholders. MISO has initiated a process to collect stakeholder input and provide guidance on preferred DER settings associated with response to abnormal grid conditions.

Abnormal conditions, whether related to distribution or transmission events or circumstances are difficult to forecast. At this time, we do not have a method for forecasting where abnormal conditions may manifest and their effect on the system. As industry knowledge and experience on advanced inverter settings grows, there may be an opportunity to develop methods for high-level prediction of potential areas with abnormal conditions and how they can be address with new functionality. The Company views Minnesota statewide DER Technical Interconnection and Interoperability Requirements being developed in Phase II of E999/CI-16-521 docket as the proper place to address DER abnormal response functions.

D. Impact of IEEE 1547-2018 on Statewide Interconnection Standards

As we have discussed, IEEE 1547-2018 is a recently published DER interconnection and interoperability standard. As also noted, we are in the process of developing a roadmap for adopting the standard and determining implementation pathways for the numerous options it offers. The roadmap will have near- and long-term perspectives.

The revised standard addresses three new broad types of capabilities for DER: (1) local grid support functions; (2) response to abnormal grid conditions; and (3) exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E999/CI-16-521 docket, especially in Phase II, which considers statewide technical standards, and other details are expected to be associated with Company business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E999/CI-16-521 docket. The response from MISO included a plan to convene a stakeholder group so that guidance on the topic could be provided on a regional basis.

E. Advanced Inverters Response to Abnormal Grid Conditions

IDP Requirement 3.A.33 requires the following:

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

A driving factor for modifying national interconnection standard IEEE 1547-2018 is to require DER to provide support for wide area grid disturbances originating from the bulk electric system (Transmission and Generation). The standards apply to all DER, including PV inverter-based generation. Historically, DER was required to trip for minor grid disturbances. A large amount of DER tripping all at once has the potential to worsen the grid condition that caused the DER to trip in the first place. IEEE 1547-2018 requires the capability to ride-through grid voltage or frequency disturbances and allows a wide range of trip settings to provide Regional Transmission Operators, Independent System Operators, Transmission Operators, and Distribution Operators with options that balance the sometimes-differing technical objectives of these stakeholders. MISO has initiated a process to collect stakeholder input and provide guidance on preferred DER settings associated with response to abnormal grid conditions.

Abnormal grid conditions such as voltage or frequency disturbances are difficult to forecast as they are typically associated with rare events such as large generators tripping or transmission line faults. Furthermore, the location of a faulted circuit greatly impacts the resulting voltage disturbance observed across the system. In contrast, any frequency disturbances observed in Minnesota are system wide phenomena across the entire Eastern Interconnect. Transmission line faults and voltage disturbances are the more common when compared to generator tripping and frequency disturbances. In general, system studies that evaluate the impact of abnormal conditions look at the worst-case anticipated condition. Using a voltage disturbance to illustrate, one would look to find the most severe voltage depression caused by a transmission line fault in order to anticipate and mitigate any adverse impact to the electric system. The Company anticipates analysis along these lines will be part of the MISO stakeholder process and that appropriate guidance will be issued on the use of advanced inverter abnormal response function. The Company views Minnesota statewide DER Technical Interconnection and Interoperability Requirements being developed in Phase II of E999/CI-16-521 docket as the proper place to address DER abnormal response functions.

VII. CHANGES OCCURRING AT THE FEDERAL AND REGIONAL LEVEL

IDP Requirement 3.C.4 requires the following:

> *Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations [RTO] and Independent System Operators [ISO]).*

In our 2018 IDP we discussed Federal Energy Regulatory Commission (FERC) Order No. 841, which addresses two different levels of participation of storage resources in wholesale markets. Since the last IDP, FERC issued Order No. 2222, which removes barriers for distributed energy resource (DER) aggregations to participate in wholesale markets. We discuss these Orders largely in the context of Order 2222 which deals with all both storage and non-storage DER aggregations participating in wholesale markets.

As noted by Commission Staff ,[16] the Commission has seen crossover with the DGWG and IDPs, hosting capacity analysis, grid modernization investments, and more. Staff anticipates more robust discussion of anticipated impacts of the FERC Orders in utility 2021 IDPs. We provide a robust discussion of the FERC Orders in the section and specifically, the potential impacts of the Orders in part D below.

A. Order Nos. 841 and 2222

FERC Order No. 841, adopted in February 2018, requires that RTOs and ISOs accommodate the various types of services that electric storage resources can provide, regardless of whether they are interconnected at transmission voltage or to the distribution system. In September 2020, FERC expanded the requirements applicable to participation of resources interconnected to the distribution system in wholesale markets with issuance of Order No. 2222 in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators.[17]

We see minimal challenges associated with implementing Order 841 as it relates to storage resources interconnected to the transmission system, as it does not pose any material additional burdens on utilities; though RTOs/ISOs will have to adjust their market rules and systems to accommodate such storage resources.

FERC's Order 841, to the extent it addresses wholesale market participation by DER storage resources, and FERC's Order 2222, left many key details regarding implementation to resolution by RTOs/ISOs and distribution utilities. We are working to understand the implications of the order from both the wholesale market level, and more importantly the distribution system level. Our primary focus in these efforts is to ensure the continued integrity of wholesale markets and the safety and

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[16] See Docket No. E002/CI-16-521, Staff Briefing Papers for the May 20, 2021 Commission Meeting, Pg. 22.
[17] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

reliability of the distribution system while also trying to work through the information systems and personnel requirements that will be required to implement and administer the rule from a distribution utility standpoint. Under the rule, FERC has jurisdiction over the manner in which DER storage resources and DER aggregations participate in wholesale markets while FERC has devolved to the Relevant Electric Retail Regulatory Authority (RERRA), the responsibility for regulatory requirements needed to maintain the safety and reliability of the distribution system and allocation of costs associated with accommodating market participation by DER storage resources and DER aggregations.

Even at low penetration levels of DER, FERC's expectation that electric storage resources and DER aggregations be enabled to participate in wholesale RTO or ISO markets poses challenges. The implications of these challenges become more significant at higher penetration levels. For example:

- *Distribution System Upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DER. In addition to the technical considerations, issues such as cost assignment will need to be addressed. As they are today for interconnection to the transmission system for participation in the wholesale market, we believe the costs of such upgrades at the distribution level should be directly assigned to the DER causing such costs to be incurred.

- *Aggregation Reviews.* As part of the RTO/ISO process for registering proposed aggregations, distribution utilities will be afforded the opportunity to evaluate whether the concerted actions of the DER participating in the aggregation will have potential adverse impacts on the safety and reliability of the distribution system. The performance of aggregations in the wholesale market will differ from the impacts studied at the time of interconnection and will likely be much more dynamic than the impacts of the typical DER, resulting in fairly complex studies. Additional staff resources and tools may be needed to perform aggregation reviews.

- *Distribution Operations.* Electric distribution companies (EDCs) will need to have the capability to monitor activities of DER in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will likely require enhanced communications systems between the EDC, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; DER and aggregation tracking systems; and additional operations personnel to effectively manage the impacts of DER participation in markets.

- *Metering*. Participation of DER aggregations raises the question about the capability to use metering to distinguish between wholesale activities and retail activities in the case of dual-use facilities. For storage resources, charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging and discharging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be used for a retail purpose.
- *Wholesale market issues*. In addition to the direct distribution-level impacts of DER aggregations participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include applicable wholesale market metering requirements; operational coordination among the RTO/ISO, EDC and DER aggregator; and whether market software can effectively be deployed to manage large numbers of relatively small resources. Through their stakeholder processes, RTOs and ISOs are working through these issues in the context of developing proposed revisions to their wholesale tariffs. Such revisions will be subject to FERC approval.

Given the broad scope of RERRA responsibilities associated with implementation of Order 2222, we expect that distribution utilities will need to develop a state-jurisdictional tariffs and agreements that address the rights and responsibilities of both distribution utilities as well as DER storage assets and DERs and their aggregators in terms of utilization of the distribution system to enable their participation in the wholesale markets. In addition, RERRAs will need to consider requests for funding of additional personnel and systems to accommodate such wholesale market participation, and the appropriate assignment or allocation of such costs.

Xcel Energy is committed to supporting DER aggregations and storage resource participation in wholesale markets. In an effort to work through solutions/ recommendations to some of the issues discussed above, Xcel Energy joined a collaboration initiative led by Advanced Energy Economies (AEE) to bring together DER developers/aggregators and EDCs to discuss common challenges associated with the implementation of Order No. 2222. Since March 2021, representatives from Xcel Energy have met regularly as part of four AEE working groups: (1) Investment and Cost Recovery; (2) Dual Participation; (3) Interconnection and Aggregation Reviews; and (3) Communication, Collaboration and Control. The work product of the effort, which will be complete in Fall 2021, will provide RERRAs with insight into areas of agreement among EDCs and DER developers with respect to Order No. 2222 implementation.

B. MISO

MISO filed its Order No. 841 compliance filing in December 2018 with the provisions regarding DERs, as we laid out in our November 2018 IDP.[18] Subsequently, in their response to FERC's request for more information filed in April 2019, MISO updated their Distribution Connected Electric Storage Resource (ESR) form agreement to require an attestation from the ESR that all necessary metering and other arrangements are completed before they can participate as a distribution connected ESR in MISO. The Company supported this revision. FERC accepted MISO's Order No. 841 compliance filing in November 2019 with an effective date of June 2022. However, MISO made a compliance filing in March 2021 requesting a delay of implementation until March 2025. MISO reasoned that a deferral of their Order 841 implementation would allow them to accelerate their existing MISO Market System Enhancement project which is expected to improve the ISO's capabilities to meet emerging reliability

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[18] Excerpt from 2018 IDP regarding key aspects of MISO's compliance filing:
One of the key aspects of MISO's compliance filing will be the relationship between MISO, the DER, and the applicable distribution system operator (DSO). After reviewing MISO's draft agreement with the DER, we have tentatively concluded that it may be appropriate to file a tariff at FERC that would address aspects of DER participation in wholesale markets. If the Company were to go forward with this concept, the tariff would address matters such as direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER.

needs. In May 2021 FERC denied MISO's request. MISO filed a request for rehearing in June 2021, and FERC again denied the request in July 2021. Therefore, MISO's approved effective date for Order No. 841 compliance remains as June 2022.

In Order No. 2222, FERC established a compliance date for the RTOs/ISOs of July 19, 2021. MISO filed a request to extend that date until April 18, 2022 and FERC granted MISO's request. In January 2021, MISO held the first meeting of its DER Task Force (DERTF).[19] The DERTF has met every regularly since then and will continue meeting until MISO makes its Order No. 2222 compliance filing in April 2022. Xcel Energy is actively participating in the DERTF, and an Xcel Energy employee currently serves as the vice-chair of the DERTF. In addition to the regular monthly meetings of the DERTF, MISO has held one workshop to coordinate Order No. 2222 implementation with the RERRAs[20] and has another workshop planned for October 22, 2021.[21]

C. Potential Impact of FERC Orders

There are a number of issues associated with Order No. 2222 implementation that will not be addressed by the RTOs/ISOs and will fall to the RERRA to resolve. These include:

- *DER Interconnections.* In Order No. 2222 and again in Order No. 2222-A, FERC declined to exercise jurisdiction over the interconnection of individual DER that interconnect to the distribution system for the purpose of participating in wholesale markets. The details of how these interconnections are facilitated, what studies are performed, and allocation of costs for any system upgrades will fall to RERRAs. While Minnesota already has a standard distribution interconnection process (the Minnesota Distributed Energy Resource Interconnection Process or MN DIP) and the Company has interconnection tariffs in place, these were not developed with wholesale participation in mind. As more DER interconnect to participate in wholesale markets, and more DER use the distribution system as a vehicle to access the transmission system, these interconnection studies and processes may need to be re-evaluated to ensure

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[19] *See* MISO's DERTF webpage at: https://www.misoenergy.org/stakeholder-engagement/committees/DERTF/. Last accessed October 19, 2021.

[20] Access the recording of this DERTF meeting at: https://cdn.misoenergy.org/20210728%20RERRA%20O2222%20Coordination%20Workshop%20Recording578273.mp4. Last accessed October 19, 2021.

[21] *See* meeting materials at: https://www.misoenergy.org/events/relevant-electric-retail-regulatory-authorities-rerra-o2222-coordination---october-22-2021/

the ongoing safety and reliability of the distribution system and to prevent cost shifts for the use of the distribution system by DER developers/aggregators to retail customers.

- *DER Aggregation Review*. FERC Order No. 2222 provided for a process by which the RTO/ISO would provide for the EDC to perform a review of any proposed DER aggregations prior to their participation in the wholesale market in order to ensure the DER aggregation has no adverse effects on the safety or reliability of the distribution system. While the process for implementing the review falls under FERC jurisdiction and will be outlined by the RTO/ISO, the details of how the EDC will perform the review and what will be studied intersects with the RERRA's authority over distribution system reliability.
- *Dual Participation*. Order No. 2222 allows for DER in aggregations to participate in both wholesale markets and retail programs as long as the DER is not double compensated for the same service in both markets. In multi-state RTOs/ISOs, such as MISO, the RTO/ISO will need to rely to a large degree on RERRAs to determine which state retail programs are compatible with dual participation in wholesale markets and which are not. Failure to adequately identify and prevent inappropriate dual participation could result in higher costs to retail customers, as customers would pay once for the service as part of a retail program and then pay again for the same service as part of wholesale rates.
- *Distribution Asset/Operations Management Systems/Software*. As the number of DER participating in wholesale aggregations increases, EDCs will increasingly need more sophisticated processes, procedures, and tools – not to mention human resources – to efficiently process interconnection requests, perform aggregation reviews, track individual DERs and DER aggregations, and safely and reliably operate a distribution system that will increasingly be used to facilitate DER access to wholesale markets. These management systems are in the nascent stages of development and will require significant customization in order to integrate into existing distribution provider infrastructure. Order No. 2222 did not address how the costs of these systems would be allocated. As a result, these decisions will fall to RERRAs to determine how best to balance the increased costs between retail customers, DER developers interconnecting to the distribution system for retail purposes, and DER developers/aggregators to access wholesale markets.

Finally, we note that we expect issues regarding data security and privacy will also need to be addressed.

APPENDIX E2: DISTRIBUTED ENERGY FORECAST METHODOLOGY AND FORECASTS

In this section, we provide the DER-related information specified in the IDP Order. As a point of reference, the IDP Order defines DER as follows:

> *Supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.*

Specifically, IDP Requirement Nos. 3.A.6, 3.A.17-25, and 3.A.31-33, which includes explanations regarding how DER is treated in load forecasts, present and forecasted DER levels, and DER scenario analysis.

I. DER CONSIDERATION IN LOAD FORECASTING

IDP Requirement 3.A.6 requires the following:

> *Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology.*

We discuss how DER is factored into both the corporate load forecast and the distribution system planning forecasts below.

A. DER Treatment in the Corporate Load Forecast

The Company's corporate sales forecast relies on econometric models and other statistical techniques that relate our historical electric sales to demographic, economic and weather variables. We also make adjustments for known and measurable changes by large customers, and to incorporate the effects of our customers' energy efficiency, distributed generation solar PV adoption, and electric vehicles. The resulting sales forecasts for each major customer class in each state across the Xcel Energy footprint are summed to derive a total system sales forecast.

The sales forecast is converted into energy requirements at the generator by adding energy losses (See *Appendix A4: Distribution System Statistics* for a discussion regarding loss factor percentages). The system peak demand forecast is developed using a regression model that relates historical monthly base (uninterrupted) peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. Distribution Planning compares their summed/bottom-up feeder level forecast to the overall peak demand forecast for reasonableness, as discussed in *Appendix A1: System Planning.*

1. *Forecast Adjustments*

After determining the base forecast, we develop net forecasts that include adjustments for future demand-side management programs, distributed solar behind-the-meter generation, and electric vehicles. We also account for the effects on the system peak demand forecast of our load management programs by subtracting expected load management amounts to derive a net peak demand forecast.

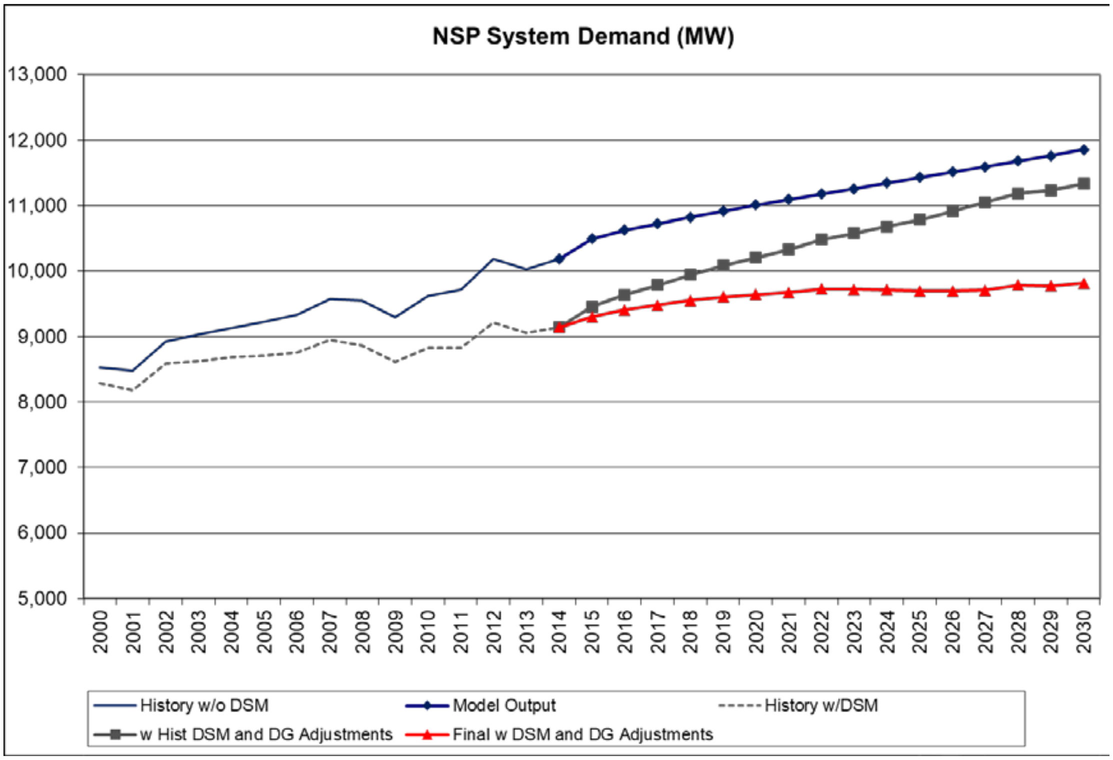
Demand-Side Management Programs. One important adjustment to the forecasts is the impact from our conservation improvement programs. The sales model implicitly accounts for some portion of changes in customer use due to conservation and other influences by basing projections of future consumption on past customer class energy consumption patterns. In addition, the regression model results for the residential and commercial and industrial classes and for system peak demand are reduced to account for the expected impacts of Company-sponsored DSM programs.

The DSM methodology for the state of Minnesota (and South Dakota) follows these distinct steps:

- Collect and calculate historical and current effects of DSM on observed sales and system peak demand.
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales and peak demand to show hypothetical case without DSM).
- Adjust the forecast to show the impact of all planned DSM in future years.

The Company-sponsored Minnesota DSM adjustments are based on the Company's July 1, 2020 Minnesota Resource Plan Supplement. Figure 1 graphically illustrates the DSM adjustment described above.

Figure 1: Illustrative DSM Adjustment



Distributed Solar PV. For distributed solar, we adjust the Minnesota class-level sales forecasts and the system peak demand forecast to account for the forecasted impacts of customer-sited behind-the-meter solar installations on the NSP System. Specifically, this adjustment is based on expected installed capacity targets (both Solar*Rewards and non-Solar*Rewards. Impacts of customer-sited behind-the-meter solar installations are extracted from this forecast to develop adjustments to reduce the class-level sales for Minnesota and the NSP System peak demand forecast. The sales and peak demand forecasts are not adjusted for community solar gardens or distribution-connected utility-scale solar because these do not affect customers' loads.

Electric Vehicles. The sales and system peak demand forecasts are adjusted to account for the impact of light-duty, medium-duty, and heavy-duty electric vehicles. The EV forecast is developed internally based on assumptions related to both adoption (energy) and charging behavior (demand) as described in Part C of this section. Inputs to the adoption models include electricity prices, vehicle battery prices, gasoline prices, car ownership, car usage, and efficiency. Both the managed and unmanaged charging behavior is estimated using data obtained from a third-party consultant (Guidehouse) for light, medium, and heavy-duty vehicles.

Large Customer Adjustments. We may also make adjustments to the forecast to account for planned changes in production levels for large customers. For example, we may add sales and demand related to a customer's new incremental additional capacity that we become aware of. We may also make adjustments to reduce our requirements due to the scheduled installation of a customer-owned Combined Heat and Power generator.

2. *Data Sources*

MWh Sales and MW Peak Demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh Sales and MW Peak Demand. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand used in the modeling process.

Weather Data. Weather data (dry bulb temperature and dew points) were collected from National Oceanic and Atmospheric Administration weather stations for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data. The Company uses a 20-year rolling average of weather conditions to define normal weather.

Economic and Demographic Data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Markit data banks, and reflect the most recent values of those series at the time of modeling.

In terms of changes to our load forecasting methodology as it relates to DER, we started incorporating distributed solar PV beginning in 2014, and in 2018 began including EVs.

B. DER Treatment in the Distribution Planning Load Forecast

As we discussed in *Appendix A1: System Planning*, we do not currently factor the impact of DER generation into the feeder-level forecasts we use for system planning purposes. However, these forecasts are rooted in historical actual peak information, so are reflective of the impacts of energy efficiency and load management.

However, our newly implemented LoadSEER forecasting tool allows us to simulate the impact that our corporate load and DER forecasts might have on the distribution system. This will allow us to better understand how loading on the distribution system might change into the future with and without the impact of each type of DER. We note however that LoadSEER cannot identify any voltage constraints associated with DER so there are limitations. LoadSEER primarily provides insight into the impact that forecasted DER growth might have on system loading, and does not consider whether DER can actually be hosted at the forecasted locations; that level of analysis still requires detailed modeling using a load flow tool such as Synergi Electric. While we currently plan the distribution system based on native loading (the system loading without the load-masking impact of DER generation), understanding both net loading and native loading will help us to anticipate the range of possible loads that may actually manifest on the system in various conditions. This probabilistic assessment will help better inform distribution planning when conducting risk analysis and developing project plans.

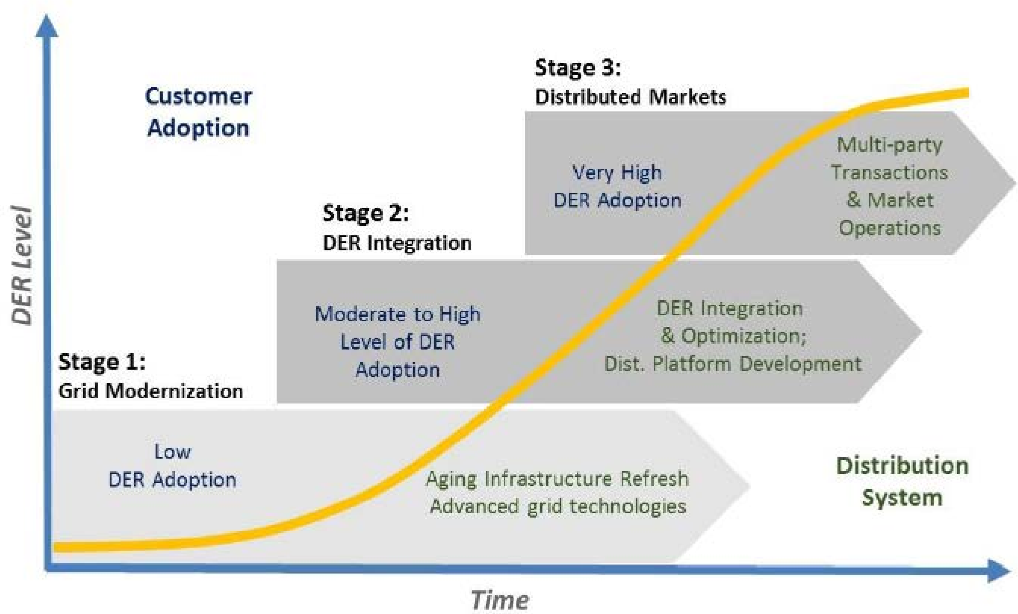
LoadSEER will allow us to integrate forecasts for DER into the distribution system planning forecast to help our planners understand the impacts that continued DER growth might have on distribution system loading in the future. We do note that the impact of DER is very locational, meaning that local conditions such as distance from the feeder, size of the conductor, feeder loading, amount of other DER present and the size of projects will all influence how well DER can be accommodated without additional impacts. The company cannot always predict where developers will place solar gardens and therefore more granular forecasts will be less accurate. LoadSEER will be able to provide directional insights but further studies will be needed during the interconnection process to fully understand whether DER can be connected in a certain location.

While there are no definitive answers at this point as to how, and how fast enhanced planning for DER will occur, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run,"– is important.

We agree that a staged and measured approach to enhanced planning is necessary. Numerous efforts from states, the DOE, and other organizations have used the customer driven Distribution System Evolution Framework shown below in Figure 2 to describe how the growth in DER adoption and related policies correspond to the distribution modernization capabilities required. Public policy varies on a state-by-state basis, and state policy is a key driver of DER adoption. As policy evolves and penetration levels of DER increase, we recognize the importance of distribution system planning and capabilities to keep pace. Utilizing a "walk, jog, run" approach helps define the roadmap identifying the technology, processes and steps needed to accommodate higher levels of DER, streamline processes, all while meeting reliability and safety objectives

Various changes in both distribution planning and operations are needed in each stage to ensure reliable distribution operations – all resting on foundational elements that enable increased utility tools and information to be in place. Much of the recent and expected DER growth in Minnesota is from CSG, which are present on 15 percent of the feeders in our state. In considering the staged evolution portrayed in Figure 2 below, we believe Minnesota is migrating to Stage 2 in terms of DER penetration, which the DOE further describes as grid modernization, focusing on "enhancing reliability, resilience and operational efficiency while addressing aging infrastructure replacement." We are starting to take some Stage 2 actions to address the pockets of high DER penetration and to avoid similar issues from arising on other parts of our system as DER more broadly expands.

Figure 2: Distribution System Evolution (Source: DOE)

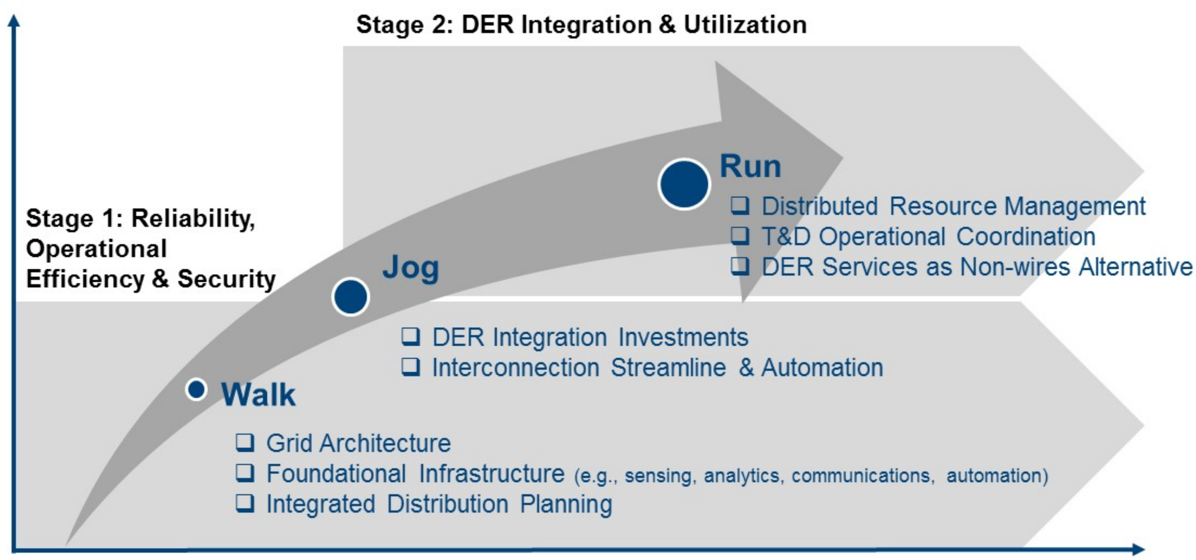


Source: *See Modern Distribution Grid, Volume III: Decision Guide*, Page 15, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

The investments that we are currently making in asset health and grid modernization, such as ADMS help to lay the foundation for continued resiliency and reliability as we deploy more grid modernization investments.

The below Figure portrays the timing and pace considerations for DER integration and utilization. Stage 1 includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication and other systems such as the FAN and ADMS, both of which are part of our near-term advanced grid plans; it also includes integrated distribution planning, which our LoadSEER tool supports.

Figure 3: Timing and Pace Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

Stage 1 is also focused on other foundational infrastructure we are intending to implement, including additional sensing, analytics, and automation capabilities such as the FLISR initiative, included in the Company's multi-year rate cased filed concurrent with this IDP on November 1, 2021[1]. Finally, we note that we are also taking Stage 2 actions – exploring integration of hosting capacity analysis with the interconnection process among other things, which we will continue to focus on with stakeholders in

[1] Docket No. E002/GR-21-630.

2022.[2] According to this concept, we are progressing from Stage 1 into Stage 2, with DER integration actions occurring in in concert with maturing our foundational advanced grid capabilities.

Using these concepts as a base, we provide a snapshot of how we contemplate evolving our planning tools and process, applying to our tools, process steps, and actions as sophistication of analysis and processes increase over time as Table 1 below. We note that this Table is an extension of Tables 1-3 in *Appendix A1: System Planning*, which portrays our present planning tools.

Table 1: Planning Tools Evolution

		Current Process Steps					Future Planning Actions				
	TOOLS	**Forecast**	**Risk Analysis**	**Mitigation Plans**	**Budget Create**	**Design & Construct/ EDP Memo**	**Long Range Plans**	**Interconnection Processing****	**Scenario Planning**	**Integrated Resource Planning**	**Locational Net Benefit Analysis**
Current Tools	**Synergi Electric**		X	X			X	X			X
	MS Excel		X		X		X				
	CYMCAP		X								
	GIS			X			X	X	X		X
	SCADA	X									X
	Workbook (internal)		X	X	X	X					X
	DRIVE***		X	X				X			
Expanded Tools	**LoadSEER***	X					X	X	X	X	X
	ADMS	X							X		
	SAP					X					

*** *LoadSEER* replaced DAA, which we removed from this chart**
**** Planning has larger role in interconnection process**
***** Hosting Capacity becomes integrated into planning process**

Walk Jog Run

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[2] *See* the Company's evaluation of investments needed to increase the cadence of its hosting capacity to monthly and at the same time, affect improvements/integration with the interconnection process in Docket No. E002/M-20-812. Although the Order is not yet issued, verbal decisions at the Commission's September 30, 2021 hearing would require continued stakeholder engagement on the Commission's hosting capacity analysis priorities. *See* Docket No. E999/CI-16-521 IN THE MATTER OF UPDATING THE GENERIC STANDARDS FOR THE INTERCONNECTION AND OPERATION OF DISTRIBUTED GENERATION FACILITIES ESTABLISHED UNDER MINN. STAT. § 216B.1611

II. DER FORECAST METHODOLOGIES

In this Section, we present our forecasts for each DER type and summarize our forecast methodologies, which respond to IDP Requirement 3.C.1 as follows:

> *In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.*

This section also responds to IDP Requirement 3.C.2, which requires the following:

> *Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.*

We have fulfilled these DER forecasting requirements to the best of our ability. We discuss each type of DER in turn below, providing our forecast, as well as the information that informed the forecast.

A. DER Forecasting in the Industry

In this section, we discuss the state of the industry with respect to DER forecasting. DER penetration analysis and forecasting at a granular *feeder* level for purposes of informing distribution planning is complex and likely less accurate than doing so at a system level. System planning involves forecasting each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecasted by all different types. Each type has different characteristics and impacts on the system. This exponentially complicates an already complex feeder-level planning process. There are tools and software, in its early stages, that could be used to accomplish this more complex forecasting.

However, precisely and accurately predicting where DER adoption may occur on a feeder or other more targeted geographic location is still challenging.. There are several existing models to predict DER adoption, using policy outcomes, macro-economic factors, or rooftop potential. However, an EPRI technical report notes several shortcomings of these models, including the challenges in making granular adoption forecasts for individual circuits, challenges verifying consumer behavior, and scarce information about the physical premises that impacts actual potential.[3]

In short, it is challenging to predict which customers will adopt which technologies, and what the impact on the circuit associated with those customers will be. This is exacerbated in Minnesota with comparatively low adoption levels for PV, EV, and energy storage. Predicting accurate forecasts for new and emerging technologies at a system level is challenging, based in part on the lack of good historical, predictable data inherent with a fledging market. At a circuit or feeder level this issue becomes more exacerbated and more unpredictable, as there are accuracy issues with forecasting at smaller geographic levels. In addition, there is not a significant sample size of historical installations on a circuit to use for trend analysis and forecasting. Nevertheless, we are taking a measured approach to develop or acquire the capabilities, methodologies, and tools that will facilitate this type of complex analysis.

We have made it a priority to enhance our forecasting capabilities. We include DER in our bulk system forecasts, we have incorporated more detailed historical data into our modeling, and we have implemented a new advanced planning tool (LoadSEER) to identify more granular inputs and impacts of DER on feeder-level load forecasts. We also expect to evolve our forecasting capabilities over time to include new approaches.

We intend to expand our use of LoadSEER for distribution planning to understand the locational and temporal impacts of DER. LoadSEER can probabilistically spatially allocate bulk system-level forecasts for DER to various specific locations on feeder circuits. While this capability is present in the tool, we are still working to understand how this capability works, and the right way to use the capability to produce the most realistic results possible.

Although more sophisticated planning tools can provide more forecasting granularity, the challenge of achieving a more geographically accurate forecast in an emerging market remains. Market adoption in an early adoption stage is less predictable, there is less historical information, and the dynamic and competitive nature of the market impacts local adoption trends. By taking a measured approach, we are able to learn from early adopters in the industry and in turn reduce long run implementation and

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[3] *See* Applying Discrete Choice Experiment Modeling to Photovoltaic Adoption Forecasting, Electric Power Research Institute, Palo Alto, CA, p. 13 (November 22, 2017).
See https://www.epri.com/#/pages/product/3002011011/?lang=en

integration costs. That said, we used our present tools and methodologies to inform the forecasts we provide in this IDP.

B. DER Forecast – Distributed Solar PV

We offer several programs to customers interested in solar as a renewable opportunity. Specifically, we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. Until its discontinuance, customers also had the opportunity to participate in the Minnesota's Made in Minnesota program. In addition, for larger systems we offer a net-metering option. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.

1. Reference Case Assumptions

In determining our Reference Case, we updated our goals to be consistent with 2021 legislative outcomes that increased and provided incentive Solar*Rewards funding for 2021-2023. The funding for the Made in Minnesota awards program was eliminated in 2017. We assumed net-metering only system additions would continue at current annual levels through the IDP planning period. We based attrition and completion lag rates on historical analysis of canceled and completed projects and applied these to program application forecasts to derive final installation estimates for 2021-2023.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting cumulative additions of 886 MW through 2021 in this filing. For our Reference Case assumptions through the IDP planning period, we assume Solar*Rewards Community adjusts down to approximately 6 MW by 2031, which takes into account the significant early adoption of CSG, the reduction in tax benefits, and the potential for more interconnection distribution constraints.

Table 2 below provides our Reference Case forecast of distributed solar PV additions.

Table 2: Reference Case – Per-Year Distributed Solar Additions (MW/AC)

Year	Solar* Rewards	Made in MN	Made in MN Bonus	Net-metering	S*R Community
<=2021	40	15	5	54	886
2022	7	0	0	15	38
2023	7	0	0	15	65
2024	6	0	0	15	73
2025	3	0	0	15	79
2026	1	0	0	15	39
2027	0	0	0	15	20
2028	0	0	0	15	13
2029	0	0	0	15	10
2030	0	0	0	15	9
2031	0	0	0	15	6
Total	**64**	**15**	**5**	**199**	**1,238**

2. *Medium and High Forecasts*

The Medium and High scenarios hold the Reference Case for Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in most cases, that these programs are substitutes for each other. Therefore, the incremental growth in one category is interchangeable with another category.

We used the average of a Bass diffusion and an economic model to derive the forecast of rooftop solar. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Economic models use a simple payback to estimate potential adoption.

The Bass Diffusion model is calibrated using, state specific, historical solar installed capacity through December 2020. Additionally, we have incorporated into both, the Bass diffusion and economic model, a factor for the percentage of customers unable to install solar on their roof, for various reasons (i.e., renters, shaded roof, inability to access the roof…) The main variables impacting adoption in the economic payback model are installation and maintenance cost, inverter replacement, investment tax credit, utility rates and capacity factors. Models and estimates are updated as new data becomes available and estimates can vary significantly

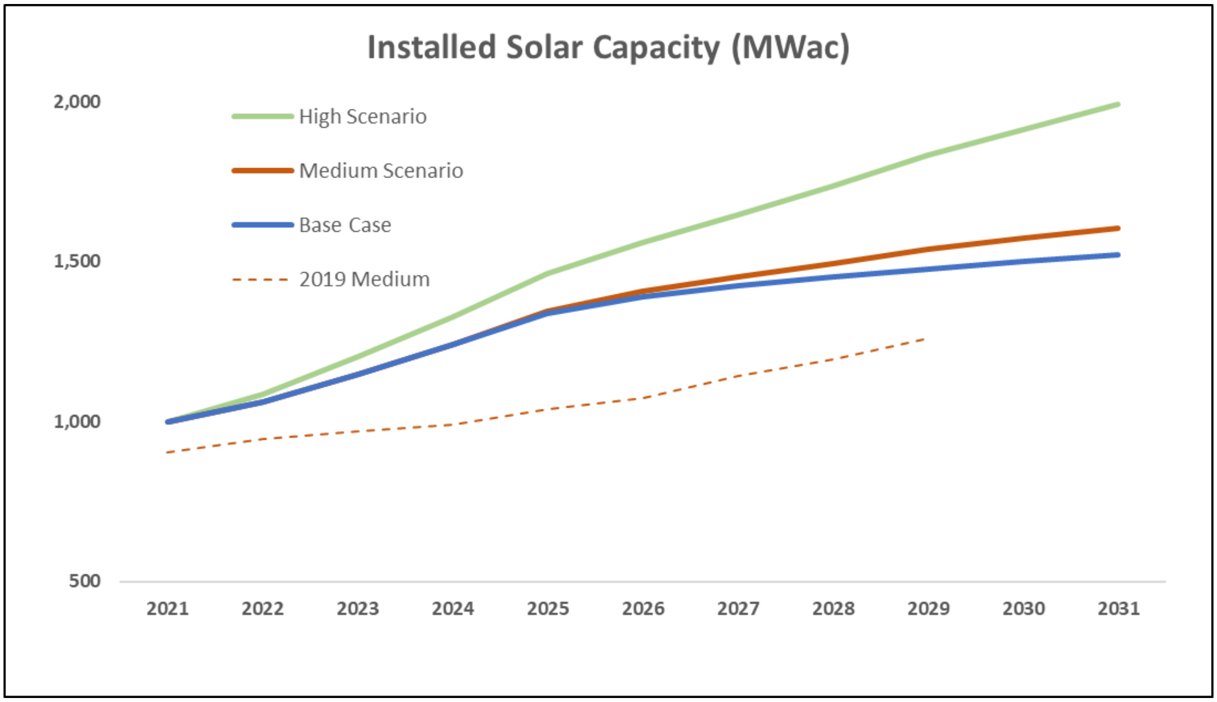
We created a high economic payback scenario using a combination of lower installation cost and higher savings. The high scenario assumes the installation costs are 10 percent lower than the medium scenario. The high scenario for the Bass Diffusion model was created using data from states that reflect high historical adoption rates. The medium scenario model results indicate around 1,605 MW for total installed distributed solar by 2031. The High scenario installed solar around 1,994 MW by 2031.

We provide a tabular and graphical view of the forecast in the following Table and Figure.

Table 3: Distributed Solar PV Forecast

	Total Base (MWac)	Total Medium (MWac)	Total High (MWac)
2021	1,001	1,001	1,001
2022	1,060	1,060	1,084
2023	1,147	1,147	1,202
2024	1,240	1,243	1,327
2025	1,338	1,345	1,462
2026	1,392	1,407	1,561
2027	1,426	1,452	1,648
2028	1,453	1,494	1,736
2029	1,478	1,539	1,833
2030	1,502	1,573	1,912
2031	1,522	1,605	1,994

Figure 4: Distributed Solar PV Forecast



C. DER Forecast – Distributed Wind Generation

We presently have very little distributed wind our system, approximately 16 MW. We believe future DER growth will primarily be through solar PV and distributed storage. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption compared to wind. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we do not provide a forecast in conjunction with this IDP.

D. DER Forecast – Distributed Energy Storage

Through mid-2021, we have received 164 interconnection applications for connecting energy storage to our Minnesota electric distribution system. From these storage system applications, 92 were either complete and in operation or granted permission to operate.[4] The current total behind the meter battery storage installed on our Minnesota distribution system is approximately 0.65 MW. We provide an annual breakdown of storage applications received and completed below:

[4] The remaining applications are in various stages of study, testing, and design and construction.

Table 4: Storage Applications – NSPM State of Minnesota

Time Period	# of Applications	Cumulative In-Service or PTO*
2017	17	6
2018	24	29
2019	28	49
2020	50	81
Mid-2021	45	92
Total	**164**	

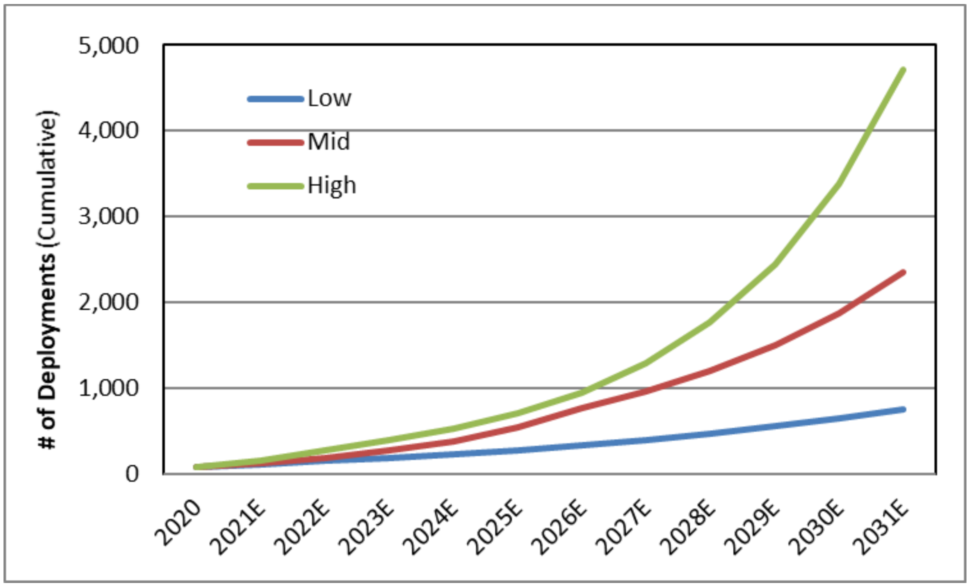
* PTO = permission to operate

In order to forecast distributed storage for our system, we utilize available data from industry consulting firms that specialize in tracking current market conditions and forecasting trends in energy storage. We have found that the availability of detailed market information on distributed energy storage is limited for the state of Minnesota. Wood Mackenzie however, currently publishes a quarterly report (U.S. Energy Storage Monitor), which provides high-level trends and forecasts that can be utilized to extrapolate a possible scenario for distributed energy storage within the Company's Minnesota electric distribution system.

For **Scenario 1** entitled "High," we utilized the actual completed energy storage units for NSP Minnesota as of the end of 2020 and then applied the forecasted forward growth rates as provided by Wood Mackenzie's most recent forecast for behind the meter storage additions. For **Scenario 2,** entitled "Mid," we utilized a Bass Diffusion model calibrated using the historical actual number of storage systems installed in the NSP Minnesota service area. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Currently all of the energy storage systems that have been installed are paired with a solar PV system. Therefore, the modeling technique to develop **Scenario 3** entitled "Low," utilizes as an input the Bass Diffusion forecast for solar PV and estimates that up to 25% of those systems will incorporate energy storage.

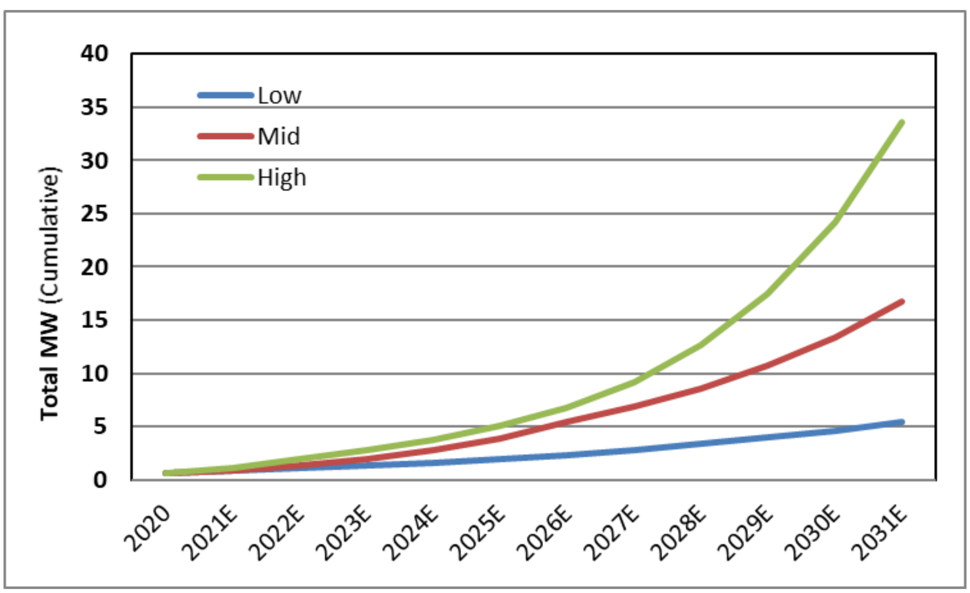
Scenario 1 results in a cumulative total of 948 energy storage units deployed within the NSP Minnesota electric distribution system by the end of 2026, while the "Low" case estimates a cumulative total of 332 units deployed. In 2031, the respective forecasts indicate a cumulative total of 4,718 units (High) and 761 units (Low), as shown below.

Figure 5: NSP Distributed Storage Forecast – Minnesota (number of systems)



Utilizing all scenarios in conjunction with an estimated average MW for each respective unit deployed, the total cumulative MW of distributed energy storage is not expected to exceed 35 MW by 2031.

Figure 6: NSP Distributed Storage Forecast – Minnesota (total MW)



Due to the emergent state of distributed energy storage within Minnesota, we note that the various scenarios developed are sensitive to externalities such as policy changes (e.g., incentive changes), technology changes (e.g., improvements in existing battery technologies and new disruptive battery technologies), and possible geopolitical risks and post-COVID supply chain disruptions that could negatively impact the availability of raw materials.

E. DER Forecast – Energy Efficiency

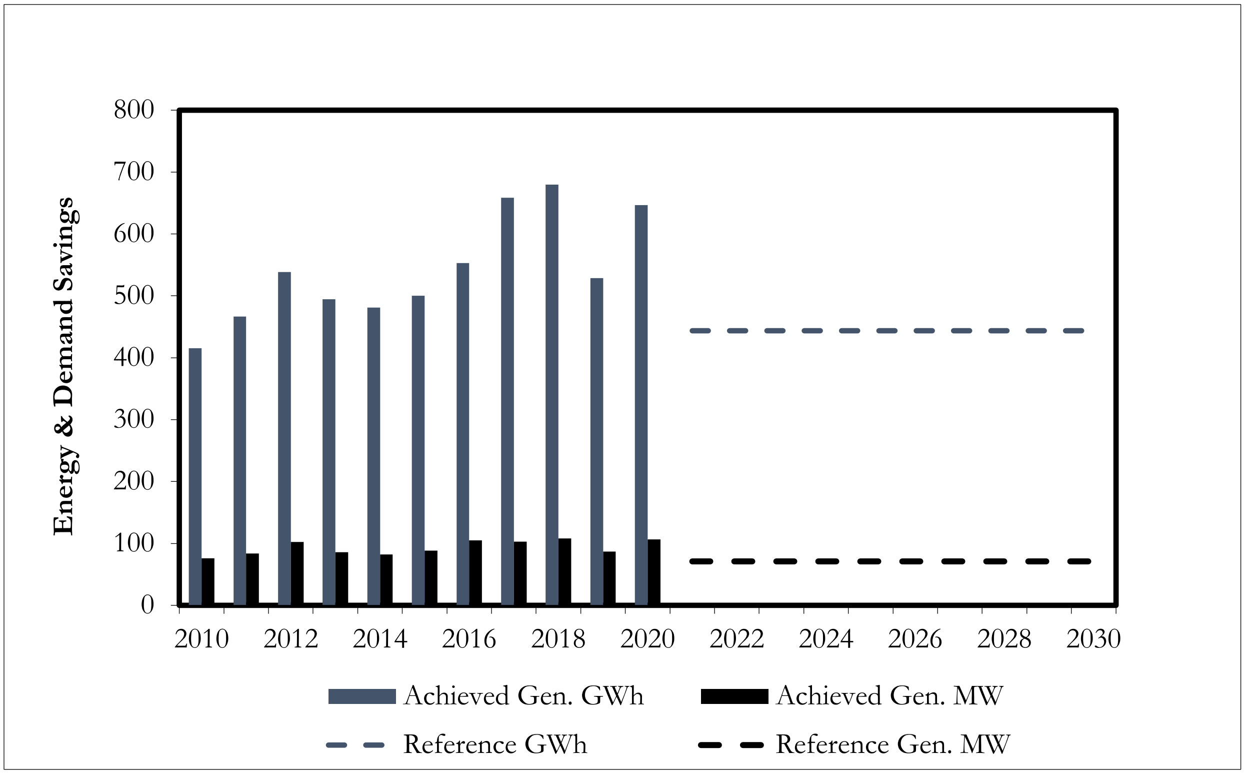
Xcel Energy has one of the longest-running and most successful Demand Side Management (DSM) programs in the country. Between 1990 and 2020, the Company spent $1.78 billion (nominal) on Minnesota DSM efforts, while saving nearly 10,991 GWh of energy and 3,886 MW of demand. Our actions to consistently adapt and judiciously grow our customer offerings have proven worthwhile as we continue to meet and exceed the state's statutory energy savings targets.

In addition to delivering energy and cost savings for customers, energy efficiency reduces the capacity need on the distribution system while providing significant benefits in carbon reduction.

1. Forecast

Our Reference Case for Energy Efficiency is set at 1.5 percent of retail sales energy savings, which is the statutory goal for Minnesota. The graph below shows historical and forecast energy efficiency annual achievements included in the forecast reference case.

Figure 7: Minnesota Energy Efficiency Forecast – Reference Case



2. *Sensitivities*

The Company has set forth goals in our 2020-2034 Upper Midwest Integrated Resource Plan (IRP) to significantly increase our energy efficiency efforts.[5] These efforts will be incremental to the 1.5 percent of retail sales energy savings with proposed cumulative goals of 11,795 GWh of energy savings and 2,156 MW of demand savings over the 2020 – 2034 planning period, including the growth of our demand response (DR) portfolio to over 1,500 MW by 2034.

In our IRP, we began the development of DSM scenarios using the Minnesota Statewide Potential Study analysis conducted on behalf of the Minnesota Department of Commerce. The study was used as the primary input for the Company's energy efficiency potential from 2020 through 2034 and included two scenarios: "Program Achievable" and "Maximum Achievable." The two scenarios differ in terms of the percent of incremental cost covered by a utility rebate. The "Program Achievable" scenario estimates adoption of measures given utility rebates equal to 50 percent of

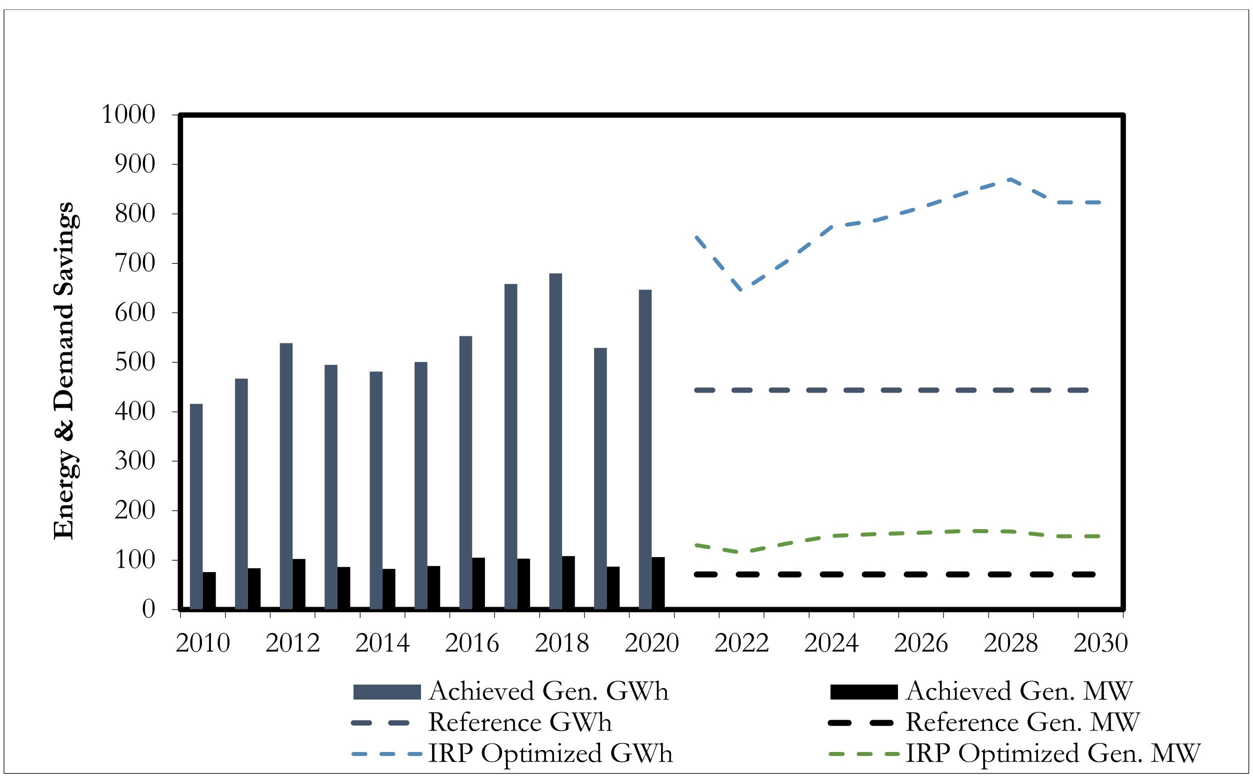
[5] *Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan,* Docket No. E-002/RP-19-368, filed with the Public Utilities Commission, July 1, 2019.

the incremental costs. The "Maximum Achievable" scenario estimates adoption at rebates equal to 100 percent of the incremental costs, effectively removing any cost barrier to adoption. Doubling the rebate levels results in higher potential impacts, but also significantly increases the cost to achieve the incremental impacts.

In addition to the two scenarios outlined in the study, we developed an "Optimized Scenario," which included a higher level of incentives for technologies that consistently save energy during on-peak hours, or hours that have the highest costs to serve, because these measures will be the most cost-effective. This is the scenario we have defined as our forecast which utilizes a retail sales energy savings target of 2.8 percent.

Each scenario was reviewed based on total system costs assuming achievement, expressed as both Present-Value of Revenue Requirements (PVRR) and Present-Value of Societal Costs (PVSC). The Optimized Scenario was determined to have the greatest cost savings under both metrics. The graph below shows historical and forecast energy efficiency annual achievements for the Optimized Scenario compared to those included in the forecast reference case.

Figure 8: Minnesota Energy Efficiency Forecast – Optimized Case



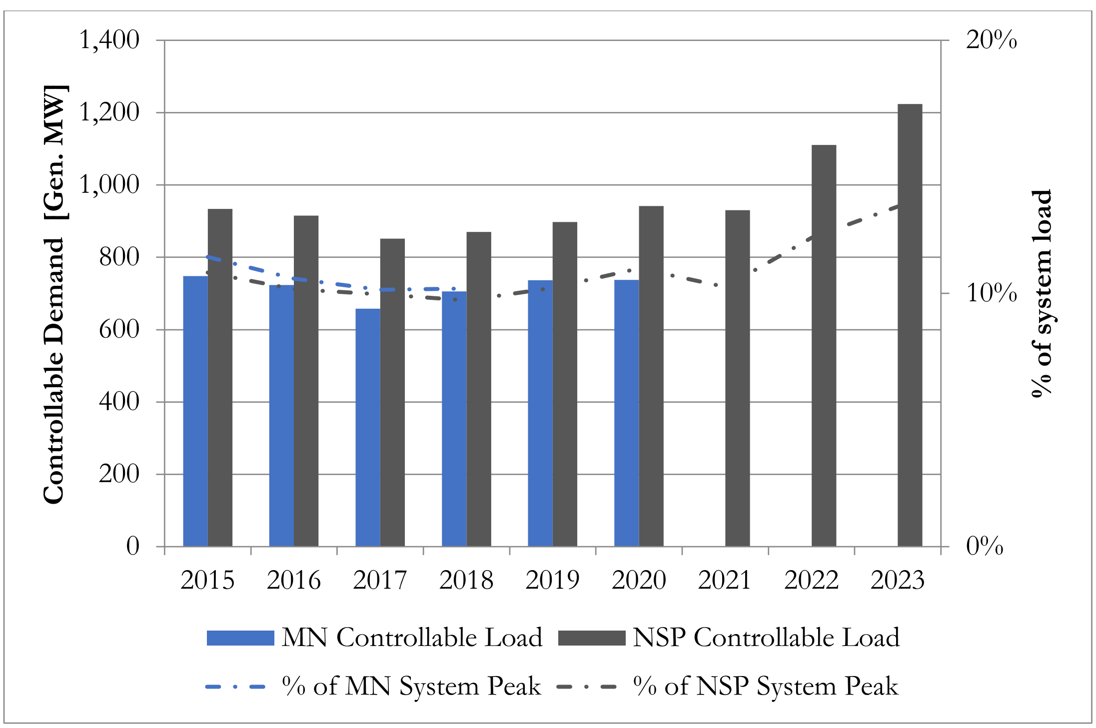
F. DER Forecast – Demand Response

We offer several programs to customers for controlling load during times of system peak. The Residential Demand Response program provides products such as Saver's Switch, AC Rewards, and Smart Water Heaters - all of which provide equipment and participation incentives to residential customers for controlling central air conditioning and eligible electric water loads. For commercial customers we offer our Electric Rate Savings, Peak Partner Rewards, Saver's Switch, and AC Rewards programs – all of which provide either bill credits or interruptible rates to help customers lower their load during utility-initiated curtailment events.

1. *Demand Response Forecast*

As discussed in our 2020-2034 IRP, we are working to increase our DR resources by an incremental amount of 400 MW by 2023. This aggressive path forward is predicated on existing programs, additional interruptible programs, new technologies, and non-traditional demand resources that encourage customer action and participation rather than just utility-controlled resources. Our Reference Case for the IDP matches the IRP analysis providing an increased amount of additional demand response to the system, as can be seen in in the below Figure.

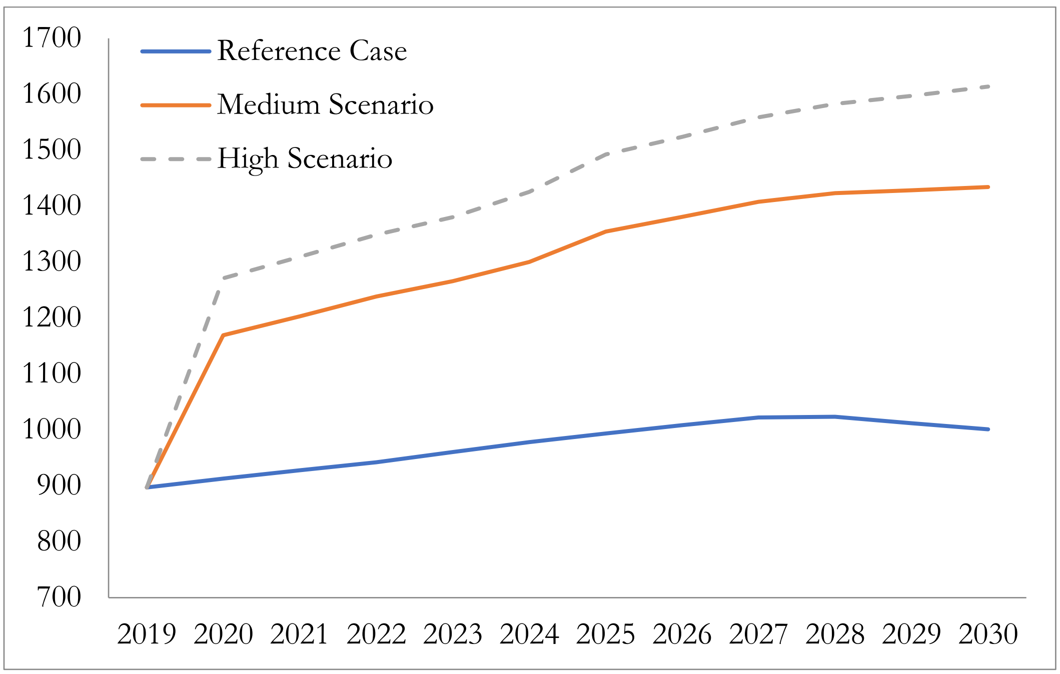
Figure 9: Minnesota Demand Response Forecast – Demand Savings



2. *Sensitivities*

In determining the Reference Case, we review existing programs and forecast future participation including attrition and adjusted commitments. The Medium and High scenarios assume an increase in demand response beyond current program levels. These scenarios are based on the cost-effectiveness analysis by The Brattle Group comparing differing levels of demand response based on customer pricing.[6] These scenarios are explained in more detail within the IRP.[7] We provide a graphical view of these scenarios below.

Figure 10: Scenario Analysis (Gen MW)



Ultimately, the preferred plan utilized the first bundle (additional incremental load identified as cost-effective).

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[6] *See* the Company's July 1, 2019 filing 2020-2034 Upper Midwest IRP, *2019 Potential Study Analysis* conducted by The Brattle Group included in Appendix G2 in Docket No. E002/RP-19-368.

[7] These scenarios are represented in the IRP as Reference Case (Demand Response Forecast), Medium Scenario (Bundle 1) and High Scenario (Bundle 2). The IRP proposes the medium scenario. No adjustments were made to these scenarios in the IRP Supplement, filed June 2020 or in modeling submitted in the IRP Reply Comments, filed June 25, 2021.

3. *Demand Response Considerations in Distribution*

As we begin to refine our forecasting opportunities with updated forecasting tools, modeling software, and future AMI technology - we will gain a more granular view of the load impact of demand response. Today, without knowing the specific load shapes and comparing them to the precise capacity constrained areas it is difficult to predict the impact to distribution. As these processes are refined, we hope to be able to match the needed load to active demand response programs and/or develop programs that can further meet these needs.

While these software tools are being implemented, the Company continues to test opportunities for demand response at a feeder level. In addition, we are conducting research and interest in our existing demand response offerings to determine future program frequency and customer interest as events lengthen and move from events limited to summer months to events happening in all seasons.

We further continue our exploration of new technologies and opportunities to shift load rather than shed only during system peaks.

G. DER Forecast – Electric Vehicles

With an increase of available models, EV adoption has increased to approximately 20,000 EVs in the state of Minnesota as of June 2021.

We currently estimate EV adoption using two modeling techniques: (1) Bass Technology Diffusion, and (2) Economic models. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Economic models use payback to estimate potential adoption and represent the second approach in modeling EV adoption.

We have estimated a low, medium, and high payback scenario for EV ownership compared to traditional internal combustion engine (ICE) automobiles. An average of the two models is used as an estimate of EVs. Our cumulative medium adoption estimate for year 2031 is approximately 6.3 percent of all registered cars and light trucks in the NSP Minnesota service territory in that year.

Our current approach is based on state specific and Xcel Energy service area specific data. The Bass Diffusion model is calibrated using state specific historical EV sales with data through December 2020. Additionally, we have incorporated into both the Bass diffusion and economic models a factor for the percentage of vehicles in urban and rural areas. Presently higher adoption is occurring in urban areas with the rural areas anticipated to ramp-up slowly.

We create high and low economic model scenarios using a combination of battery prices and gasoline prices. The high scenario assumes the battery prices are 20 percent lower than the medium scenario, and gasoline prices are higher by one standard deviation. Similarly, the low scenario assumes battery prices are 20 percent higher than the medium scenario, and gasoline prices lower by one standard deviation. The high and low scenarios for the Bass Diffusion models are created using data from states that reflect high historical adoption rates for the high scenario, and low historical adoption rates for the low scenario.

We note that EV fuel efficiency could be impacted by advances in technology; we currently assume gasoline cars average 24 miles per gallon.

Analysis indicates that battery costs are a significant factor for higher EV prices. Main variables impacting adoption are available tax incentives, price differential between EV and ICE cars, and gasoline prices. Models and estimates are updated annually with new relevant available data and estimates can vary significantly. Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust with additional data available every year.

Our estimates show significant volatility between various scenarios. The estimates are also sensitive to several externalities like policy changes (*e.g.*, incentive changes, cybersecurity requirements, carbon requirements), technology changes (*e.g.*, improvements in existing battery technologies and new disruptive battery or electric motor management technologies, autonomous vehicles, alternate technologies like fuel cell vehicles), geopolitical issues such as trade and tariff issues, availability of raw materials such as lithium, cobalt, nickel, and infrastructure availability.

Additionally, many of the inputs change frequently and could produce significant swings in the model outputs. As can be seen in the below Figures, the range of high and low estimates is fairly large, reflective of the sensitivities, volatility and uncertainty associated with the estimates.

Figure 11: Cumulative EV Adoption Rate (LDV) – NSP Minnesota Service Area

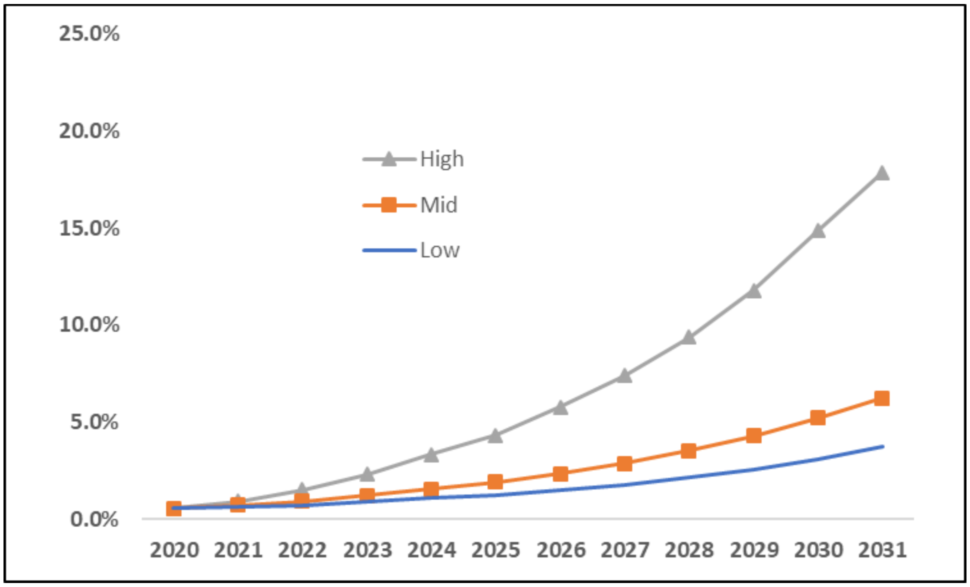


Figure 12: Cumulative Numbers of EVs – NSP Minnesota Service Area

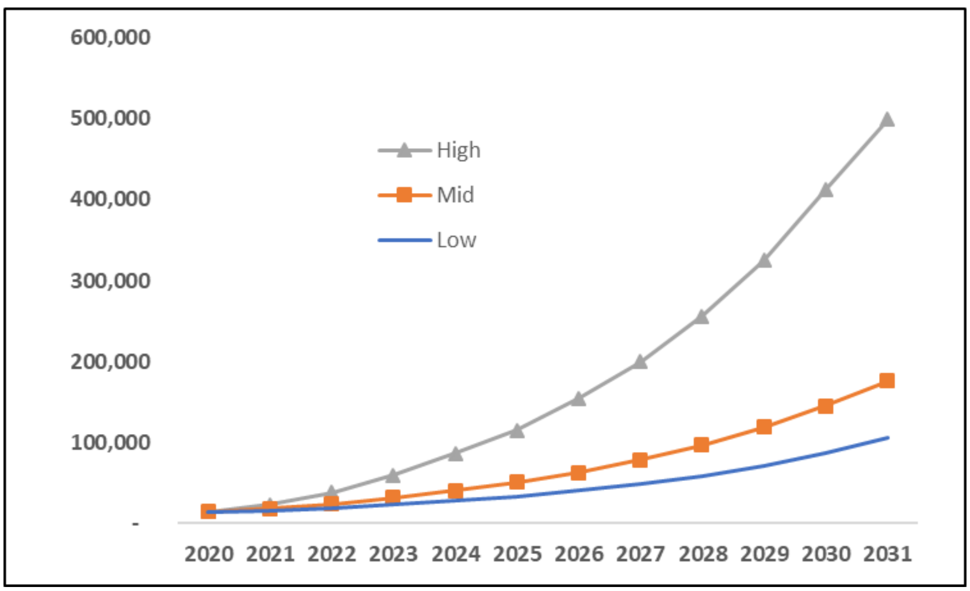
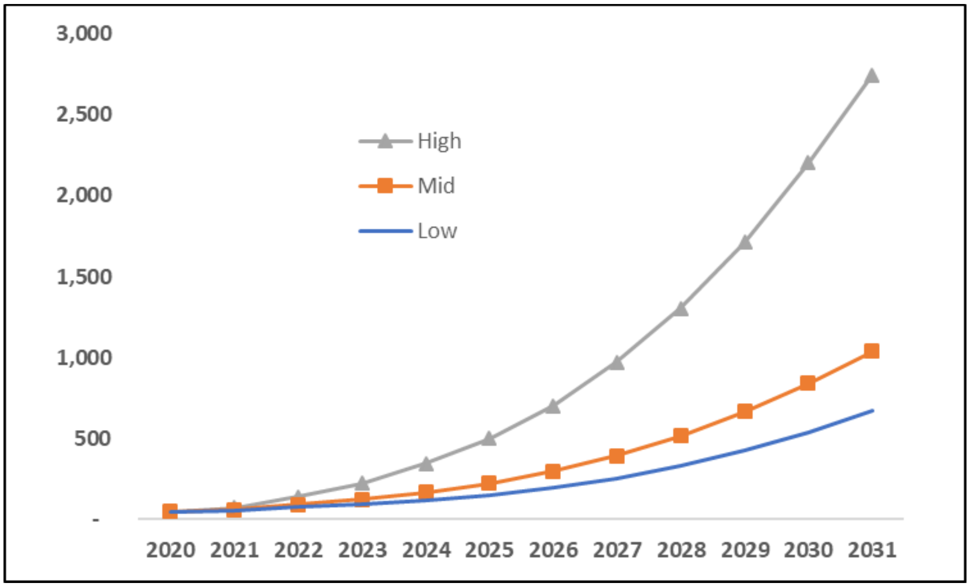


Figure 13: EV Consumption – NSP Minnesota Service Area (GWh)



We utilize estimates from a third-party consultant for medium and heavy-duty electric vehicle adoption and consumption estimates in Xcel Energy service territory. We have made benchmarking part of our annual update process to ensure that our forecast is in-line with estimates from other reputable sources.

APPENDIX F: NON-WIRES ALTERNATIVES ANALYSIS

The discussion in this Appendix responds to IDP Requirement 3.E.2, which requires the following:

> *1. Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*
>
> *2. Xcel shall provide information on the following:*
>
> - *Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)*
> - *A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)*
> - *Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed*
> - *A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.*

We provide this information in compliance with Order Point No. 6 of the Commission's July 23, 2020 Order in Docket No. E002/M-19-666, which requires the Company to engage stakeholders in further advancing our NWA analysis, including the screening criteria, analysis methodology and assumptions, and evaluation parameters. The information in this Appendix also responds to the Company's commitment in our 2019 IDP proceeding to include a broader set of values and revenue streams in future NWA analyses.[1] We held these stakeholder workshops in April 2021, and we include a summary of the outcomes and how we have incorporated stakeholder feedback below.

Finally, we note that in our November 1, 2020 Compliance filing in our 2019 IDP proceeding, we committed to provide an update on the Minneapolis-based Non-Wires Alternative (MNWA) pilot we outlined as part of our Relief and Recovery proposal in Docket Nos. E,G999/CI-20-492 and E,G002/M-20-716. We continued to explore a

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[1] *See* July 23, 2020 Order in Docket No. E002/M-19-666 at page 8.

pilot with the City of Minneapolis and as discussed in Appendix H, this initiative evolved through discussions with our partner organizations more toward supporting communities' resilience to climate change and other stressors rather than an NWA that would defer distribution investment. In this 2021 IDP, we seek certification of what we have now termed the Resilient Minneapolis Project (RMP). See Appendix H for details regarding this project.

I. OVERVIEW

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and non-traditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, we are continuing to see NWA solutions require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g., a battery-only platform or demand response-only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. We have determined that the cost of incorporating DER as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DER have the potential to quickly become a cost-competitive option. As such, we are working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

The below sections note the Commission's requirements and the corresponding aspects of our NWA analysis. We provide the full results of our NWA analysis as Attachment L.

Finally, we note that in past IDPs we have provided an update on our involvement with a non-wires alternative pilot lead by Center for Energy and Environment (CEE) in the Geotargeted Distributed Clean Energy Initiative. This initiative has concluded and CEE's final report (February 18, 2021) is available at: https://www.mncee.org/non-wires-alternatives-path-local-clean-energy-appendices

II. VIABILITY OF NWAS BY PROJECT TYPE

IDP Requirement E.2 requires, in part, that the Company provide

> *…information on …Project types that would lend themselves to non-traditional solutions (i.e. Load relief or reliability)*

In this section we discuss the three project types (mandates, asset health and reliability, and capacity) we consider in our NWA analysis. We also discuss the reasons we believe capacity projects best lend themselves to a non-traditional solution.

A. Mandated Projects

Mandated projects are projects where the Company is required to relocate infrastructure in public rights-of-way in order to accommodate public projects such as road widenings or realignments. For technical reasons, NWAs would not work well for mandated projects. If we chose to not replace distribution infrastructure due to a mandated project, we would leave a segment of customers electrically unserved due to having no physical connection to the Xcel Energy system. Those customers would then need to be served via some other local means, like distributed generation. However, if they were served by some other means, that would take away from the interconnectedness of the distribution system. This is necessary to continue reliable service because it allows the Company the ability to switch customers to other feeders during periods of planned maintenance or unplanned outages. Removing that interconnectedness takes away added flexibility and redundancy that has been intentionally designed into the system and makes operating it more difficult and less reliable. The grid offers many benefits, such as affordable reliability, and removing customers from the grid is not a viable solution for either Xcel Energy or our customers.

Beyond the technical reasoning, these projects generally follow municipal and state funding availability and consequently, are not always specifically represented in our five-year budget, especially beyond one to two years. What makes these projects even more time prohibitive is the fact that they must occur prior to the actual public project taking place. A typical example would include a project that was formally funded by a municipality two years in advance of the start of construction. This means that the municipal project design will be completed within the first year after funding was allocated, giving the Company less than one year to design its project, allocate the necessary funds, and relocate facilities in the affected areas before construction on the municipal project can begin. Implementing a detailed NWA for such a situation would be extremely difficult, if not impossible, to accomplish within such a short period of time given the complexities inherent to a totally unique and new solution that an NWA would offer.

B. Asset Health and Reliability Projects

Asset Health and Reliability projects are projects required to replace equipment that are reaching the end of life or have failed. This is a broad category that covers pole replacements, underground cables, storms, public damage repair, conversions, etc. To maintain the existing reliability of the distribution system we must spend money annually to replace our assets.

Keeping customers connected to the grid is the major reason Asset Health and Reliability projects are not suitable for NWAs. If we chose not to replace distribution infrastructure due to aging assets, there is a high level of risk that certain assets would fail, and customers would experience an outage. To avoid or prevent the outage the customers would need to be served via some other local islanded generation. From a reliability perspective, at some point our customers need to be hooked back up to the distribution grid rather than staying in a permanent microgrid. So, money is spent on infrastructure renewal regardless; it is just a matter of whether it is reactive or proactive replacements.

Unlike the mandated projects, with Asset Health and Reliability projects there is more potential for ongoing costs. A mandated project requires the movement of a particular piece of the system one time. An asset health project, because it is based on condition, can occur at many points on the system. One project could first be needed to replace deteriorating poles, then another needed to address underground cable that is going bad near the customer, then another to replace breakers inside the substation. Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA is not workable.

C. Capacity Projects

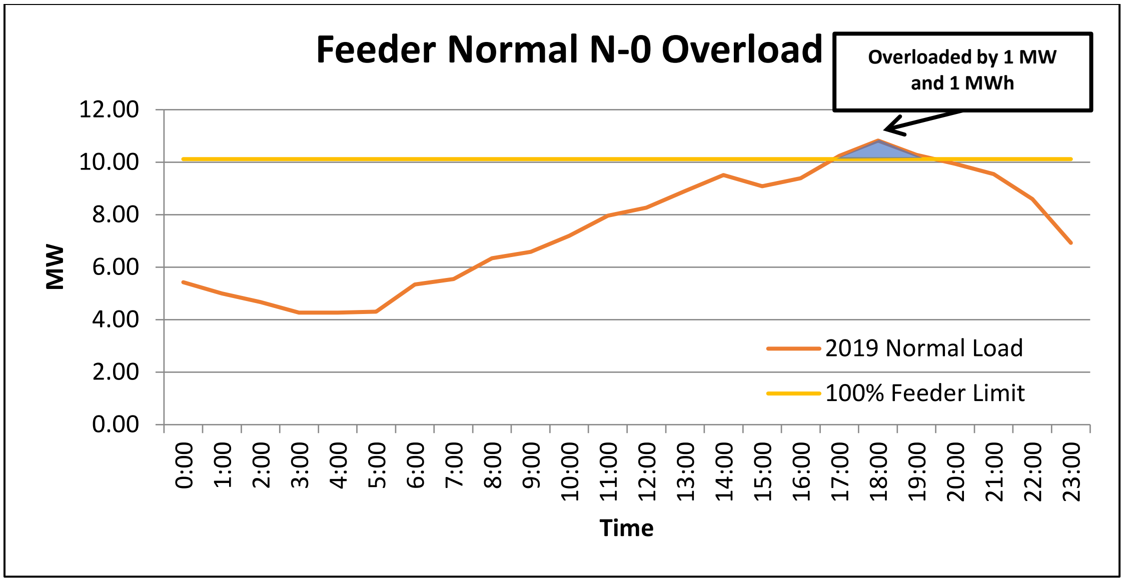
Capacity projects are better suited for NWAs as they are driven by a capacity deficiency that can be offset or otherwise deferred by strategically-sited DER. DER that can generate, discharge, or reduce the consumption of electricity downstream on a feeder can decrease the amount of load that is drawn through the substation and relieve overloads.

Because capacity projects do not have external requirements to build capacity, each project is given a priority score based on a general assessment of costs and benefits, and that score is one of the key drivers for prioritizing projects for selection in the budget. Therefore, without some additional driving need, an NWA must be cost-competitive with a traditional solution to be viable in the budget create process.

Capacity risks are identified in two different categories: N-0 (system intact), and N-1 (first contingency). Existing Distribution Planning Criteria dictate that a project needs to be identified to resolve all N-0 risks greater than 106 percent loaded, and all N-1 risks with more than 3 MVA at risk. The viability of NWAs varies between N-0 and N-1 risks due to the nature of the risk types.

N-0 risks are normal overloads that occur under system intact conditions. These typically are manifested as substation transformers or distribution feeders that have just crossed their 100 percent loading capacity threshold. We provide an illustrative example of an N-0 overload below.

Figure 1: Illustrative N-0 Overload



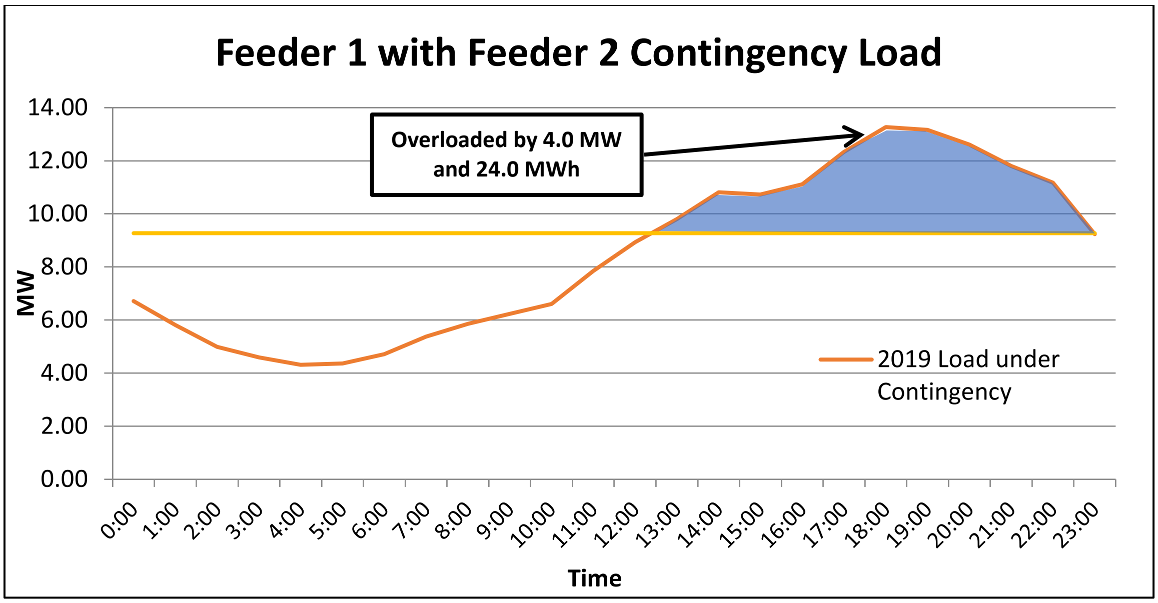
This overload is relatively small with a peak magnitude of 1 MW. Additionally, due to the small magnitude the total duration of the overload is brief as well, yielding a total of approximately 1 MWh overloaded. With a unit cost estimate of approximately $200,000/MWh and $400,000/MW for battery storage, this indicates that the overload could be mitigated with DER for $600,000. This cost estimate is cost-competitive with a typical traditional project to mitigate a comparable overload, which would consist of upgrading feeder cables or conductors, extending a feeder and transferring load, or installing a new feeder.

N-1 overload risks, on the other hand, are significantly less viable for NWAs. N-1 overloads occur when, for loss of a feeder, feeder load is transferred away to adjacent feeders, causing an overload. Per our planning criteria, projects are not required for N-1 risks until they exceed 3 MVA at risk – this means that total magnitude of the overload on the adjacent feeder(s) exceeds 3 MVA. At this level of overload magnitude, the duration of the overload extends by several hours. This excessive duration accumulates significant amounts of MWh overloaded, and in turn inflates the cost to mitigate the risk.

We show an illustrative example of a N-1 overload below. If an outage were to occur for the Feeder 2, the feeder's load would be broken up into sections and transferred to adjacent feeders. In the case of the Feeder 2, the load would be broken up into three sections. The first section can be transferred away to an adjacent feeder without causing any overloads. However, when the second section is transferred away to

Feeder 1, it causes an approximate 4 MW overload. The resulting peak day load curve for Feeder 1 after the Feeder 2 second section load has been transferred is shown below.

Figure 2: Peak Day Load Curve for Feeder 1 after Feeder 2 Second Section Load has been Transferred



The magnitude of the N-1 overload is relatively normal for N-1 risks tied to a project at 4.0 MW at risk. However, just 4 MW of load at risks causes the duration of the overload to extend to 10 hours. Therefore, the accumulated MWh during the overload totals to 24.0 MWh. With a unit cost estimate of $200,000/MWh and $400,000/MW for battery storage, the cost to mitigate this risk rises to $6.4 million. This cost estimate is multiple orders of magnitude higher than a typical traditional project to mitigate a comparable risk. A typical traditional project could consist of upgrading feeder cables or conductors, extending a feeder for a new tie, or installing a new feeder.

The load profile shown above is of similar shape to most feeders that comprise a mix of residential and commercial customers. As such, the cost estimate for the NWA can be considered representative of a typical NWA for N-1 risks of this magnitude. However, even if a 4 MW overload were to occur for only a one-hour duration (totaling to 4 MWh), it would still require $1.8 million of battery storage to mitigate the overload. While this overload duration is unrealistically short, it indicates that the cost to mitigate a 4 MW N-1 overload for even the minimum possible duration would not be cost-competitive with a comparable traditional solution. Therefore, it is not recommended that N-1 risk-driven projects are considered viable for NWAs.

III. TIMELINE

IDP Requirement E.2 requires in part that the Company:

> *…provide information on . . A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation).*

With regard to the timeline that is needed to consider alternatives to any traditional projects, for purposes of this IDP we have assumed we need about three years to appropriately consider and incorporate an NWA solution. This timeline incorporates our internal time for analysis as well as all the steps surrounding a request for proposals (RFP) to actually procure an NWA solution. This includes issuing an RFP, obtaining response, screening the responses, technical and sourcing reviews, and then contract negotiations, and construction. It is our understanding that this timeline is consistent with the approach other utilities have used in similar analyses as well. We note that we believe that as we get more experience in the NWA process, the timeline could moderate a bit. However, we expect that these projects will continue to take a significant amount of lead time.

IV. SCREENING PROCESS

IDP Requirement E.2. requires in part that the Company:

> *… provide information on the…Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed. And, a discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made*

NWA Analysis, from a holistic standpoint, is an emerging analysis that many utilities across the U.S. are just beginning to tackle. Not only do these alternatives use some non-traditional solutions but they also use traditional ones in new ways and may combine solutions to fully mitigate an issue. These complexities along with differing implementation and operational strategies will take time and considerable effort to build and maintain.

We note that we are just at the beginning of the future NWA process. Xcel Energy and the industry as a whole, is trying to create a comprehensive method that will focus on the projects that have the most potential and then evaluate them in an efficient manner against traditional alternatives. We believe much work needs to take place both from the Company and the industry before success can happen. At present, the effort needed to analyze one project for potential NWA is substantial and increases greatly according to the number of risks associated with it.

Recognizing the current IDP requirement to provide an analysis on how NWAs compare in terms of viability, price, and long-term value for projects with a total cost of $2 million or greater is an interim step, we believe long-term that the right approach to identify candidate projects will involve more than a financial threshold.

As we discussed with stakeholders at our NWA workshops, we apply several filters in our screening process including project type, cost, and timeline. We may also consider the number of risks. However, we expect to continue to refine our process to identify projects for NWAs for future reports. We applied the project filters as follows:

Project types – Project types includes mandates, asset health and reliability and capacity projects. As discussed above, mandates and asset health and reliability projects were filtered out.

Costs – Per the Commission's Order, we evaluated projects with costs greater than $2 million. However, we believe there is additional work to be done to best identify the range of projects costs for this filter.

Timeline – The timeline included in this screening process includes projects that fall in the 2023-2025 timeframe due to the timing considerations discussed above.

Risks – If applicable, the number of project risks includes both N-0 and N-1 risks.

IDP Requirement E.1 requires the following:

> *Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*

Using the above screening process, the below table provides the list of capacity projects over $2 million that fall within the required timeline. Fourteen projects fit the screening criteria for further evaluation as shown below.

Table 1: Initial Projects Evaluated

Project	2022	2023	2024	2025	2026	22-26 Total
Install Kohlman Lake KOL Feeder	$0	$0	$0	$0	$4,520,000	$4,520,000
Install Viking VKG Feeder	$0	$0	$50,000	$4,050,000	$0	$4,100,000
Install Wyoming WYO Feeder	$0	$50,000	$2,556,000	$0	$0	$2,606,000
Reinforce Veseli VES TR1	$0	$200,000	$2,550,000	$0	$0	$2,750,000
Install Zumbrota ZUM TR	$0	$0	$0	$100,000	$2,950,000	$3,050,000
Install Chemolite CHE TR03	$0	$0	$0	$0	$4,200,000	$4,200,000
Install Goose Lake GLK TR3	$0	$0	$0	$1,130,000	$4,130,000	$5,260,000
Install Orono ORO TR2 & Feeder	$0	$0	$250,000	$3,850,000	$0	$4,100,000
Reinforce Burnside BUR TR2	$0	$0	$100,000	$2,600,000	$0	$2,700,000
Install Cottage Grove CGR TR03	$0	$0	$100,000	$4,100,000	$0	$4,200,000
Install Cannon Falls Trans CTF TR2	$0	$200,000	$1,795,000	$0	$0	$1,995,000
Install Western WES TR3 & Feeders	$0	$0	$0	$0	$5,300,000	$5,300,000
Reinforce Faribault FAB TR1	$0	$100,000	$1,925,000	$0	$0	$2,025,000
Install East Winona EWI TR2	$0	$0	$100,000	$3,100,000	$0	$3,200,000

Today, NWA analysis is very time consuming and manual – especially as the risks associated with a project increase. The process requires that we pull peak load curves for feeders and substation transformers from historical monitoring data and advance that to the forecasted year of interest. Those curves are then blended together, where applicable, for contingency situations that are unique for each. We then tailor and add in demand response (DR), existing generation curves and additional solar if necessary, in order to determine final energy and demand values that can be used to size an appropriate energy storage device. This is necessary for every identified risk that a traditional project is mitigating.

Most capacity projects budgeted at greater than $2 million are intended to solve larger numbers of risks – this vastly increases the complexity of the problems to solve with a NWA, and in turn increases the amount of resources required to conduct the analysis. Projects with fewer capacity risks to solve are more localized and therefore more straightforward. We also look for any opportunities to utilize resources to solve more than one risk, such as optimally placing them at key locations on the system.

We expect future tool enhancements will help make this process less burdensome. Specifically, LoadSEER, for one, will help in the beginning of the analysis by providing the forecasted load curves. While the rest of the process will still be fairly manual for the foreseeable future, we are working within the industry to help affect change and improvement.

V. NON-WIRES ALTERNATIVES ANALYSIS RESULTS

In this section, we outline the results of our 2021 NWA analysis, which examined the fourteen projects that fit our NWA criteria, as outlined in Table 1 above. For each of these projects we focused on the forecasted 2034 peak load curve for each feeder or transformer risk involved. We then applied focused DR in an effort to reduce the load, and followed that with energy storage and/or solar generation to make up the remainder of the deficiency. In some instances, we had existing solar on affected feeders and banks that we accounted for in the analysis as well. We provide the results of the analysis, along with the load curves and assumptions used in Attachment L.

We only considered DR for the N-0 risks. This is partially due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data such as individual customer loads. By focusing on the N-0 risks at this time, we are looking to develop a process, observe the value, and determine next steps for all risks.

Table 2 below summarizes the fourteen projects, their costs, and the risk deficiencies that drive those costs. We discuss each of these project analyses in detail in Attachment L. We also clarify that these results reflect the method we have used to-date to evaluate NWAs. As we noted earlier, we engaged with stakeholders and explored a broader approach to evaluating NWA beginning in 2022, which we discuss in Section G below.

Table 2: 2021 NWA Candidate Projects – Results Summary ($ millions)

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA	Cost of Traditional Project
Install Kohlman Lake KOL Feeder	7	11.25	50.39	$17.0	$4.52
Install Viking VKG Feeder	3	10.3	62.6	$17.9	$4.1
Install Wyoming WYO Feeder	5	14.38	97.14	$28.5	$2.5
Reinforce Veseli VES TR1 & Feeder	3	10.99	69.75	$41.8	$2.8
Install Zumbrota ZUM TR	2	10.97	73.34	$41.8	$3.0
Install Chemolite CHE TR03	5	28.82	151.18	$11.8	$4.0
Install Goose Lake GLK TR3 & Feeders	8	29.53	179.03	$37.9	$6.4
Install Orono ORO TR2 & Feeder	3	15.40	279.70	$68.9	$4.1
Reinforce Burnside BUR TR2	3	17.8	135.06	$69.6	$2.7
Install Cottage Grove CGR TR03	4	64.27	321.39	$46.6	$4.2
Install Cannon Falls Trans CTF TR02 & Fdr	4	17.43	141.13	$108.0	$2.0
Install Western WES TR3 & Feeders	9	34.97	185.33	$95.4	$5.3
Reinforce Faribault FAB TR1	5	32.3	234.31	$125.8	$2.0
Install East Winona EWI TR2	6	21.79	166.46	$115.6	$3.2

We also note that in some instances, the NWA is not able to fully solve all of the risks that the traditional project solved, which makes a meaningful comparison challenging. This is in part due to contingency situations where an NWA would have to act as a microgrid for large amounts of energy. The costs for such an NWA solution would be substantially greater. The NWA solutions also solve the risks by reducing the loading down to 100 percent of the capacity rating, which means that any new load growth would create the need for an expanded or new NWA solution. In comparison, traditional capacity projects contain "spare capacity" due to the standardized equipment increments associated with the distribution system infrastructure components involved in a traditional mitigation project; this results in our ability to accommodate some new growth in the near-term.

VI. ADVANCING OUR NWA ANALYSIS

As we have noted, we engaged with stakeholders in 2021 to explore ways to advance our NWA analysis, including screening criteria, analysis methodology and assumptions, and evaluation parameters. We also explored how we might include a broader set of costs and benefits in future NWA analyses, which is sometimes referred to as "stacked values." In this section, we summarize our stakeholder process and outline the changes to our NWA methodology that we propose to make for our 2022 NWA analysis.

A. Stakeholder Engagement

We held two virtual NWA-focused workshops, one on April 23, 2021 and the second on April 30, 2021. We also had a substantial discussion about NWA in our overall IDP workshop on September 17, 2021 where we outlined what we had heard in the earlier NWA workshops and how we incorporated that into a proposal for future analyses. We summarize the workshops here and provide more details about them in Attachment I.

1. Workshop 1 – April 23, 2021

In the first workshop, we discussed the national view of NWAs, our current NWA methodology, and we introduced nationally recognized NWA attributes and valuation concepts. Stakeholders provided feedback regarding the attributes of five primary NWA types: energy efficiency, DR, storage, solar, and the combination of solar + storage. At the end of the workshop, we asked stakeholders to complete a "homework assignment" in preparation for the second workshop where we planned to discuss specific additional values and valuation concepts.

The homework was a MS Excel spreadsheet of potential benefits and costs to consider related to NWAs that we developed based on the National Standards Practice Manual by the National Energy Screening Project (NESP). We requested stakeholders to identify which of the benefits and costs are quantifiable, what sources they suggest to quantify them, ideas on how they should be integrated into an NWA analysis, and whether there are other values they would like to see added for consideration. Some of the questions we received included informational background around elements of the NWA process, questions around future considerations for NWAs, and for direction on available public documents about NWA that might be helpful to better understand an expanded NWA valuation model and methodology. Overall, we received positive feedback from stakeholders on this workshop.

2. Workshop 2 – April 30, 2021

We met with stakeholders for the second NWA focused workshop on April 30, 2021. In this session, we recapped the first workshop and addressed some questions we had received and required follow-up. Some of these follow-up items included feedback regarding industry reports offered by stakeholders, an overview of Minnesota's Value of Solar calculation, and an overview of the current demand side management cost-effectiveness analyses. We then focused on NWA valuation concepts and how to factor in other costs and attributes of alternative and traditional solutions. We used a variety of participant polls that corresponded with the homework from the first workshop that asked stakeholders to prioritize and rank the additional potential values. Further following-up on the homework we asked stakeholders to complete in advanced of the second workshop, we stepped through each category of stacked benefit with the participants – discussing how it might be valued and how much weight it might have in terms of the overall valuation of an NWA.

Finally, in the overall IDP workshop, we illustrated the current NWA process, discussing the concepts behind the proposed NWA methodology, and went through an example NWA project from both a current-valuation methodology approach and the conceptual approach we propose in this IDP for use beginning with our 2022 NWA analysis.

B. Proposed Future NWA Analysis Methodology

After considering stakeholder feedback, we have developed a future NWA methodology that we propose using beginning with our 2022 NWA analysis.

1. Comparison of Current to Proposed Methodology Framework

The updated NWA methodology we propose would potentially apply a significant number of additional values to all projects. The process has two main steps: (1) First, we conduct an initial cost and feasibility screening and projects that have a reasonable cost-benefit result progress to the second step, which is (2) we would conduct a detailed study. If the results of the detailed study and resulting sourcing process is cost-effective and meets the distribution system need, the NWA would get engineered and in-serviced. We note that the NWA solution is assumed to defer risks for 10 years from in-servicing.

Table 3 below summarizes the differences in methodology between the proposed and current approaches to NWA screening.

Table 3: Summary of Key Aspects of our Current and Proposed NWA Screening Methodologies

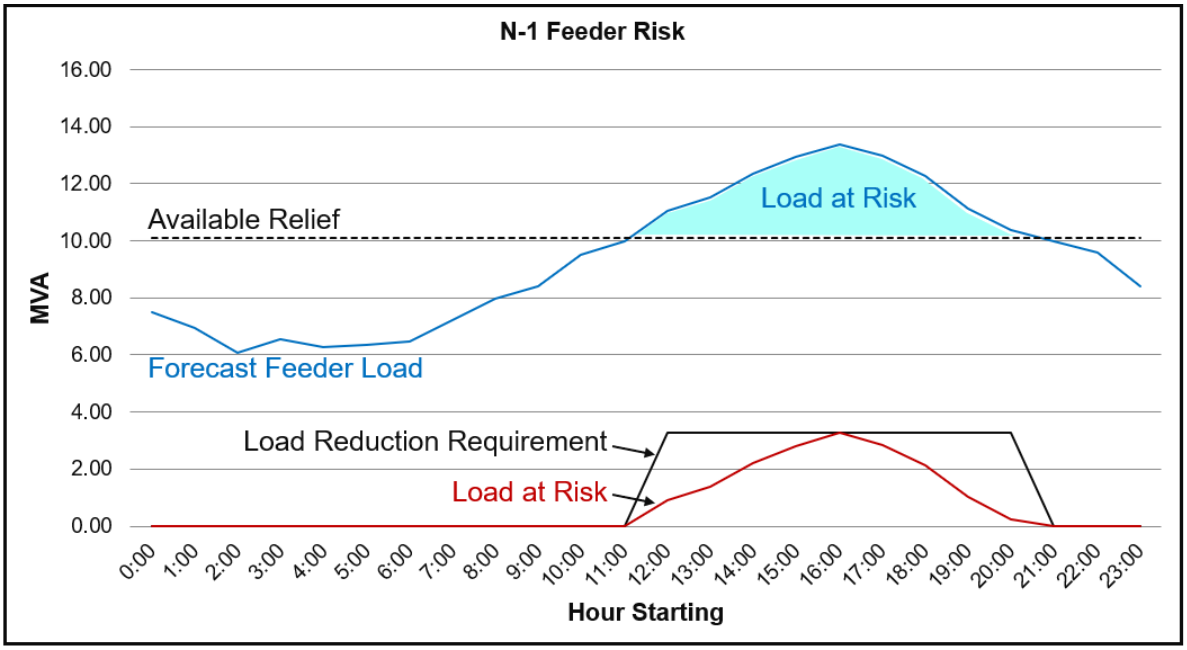
Aspect/Component	Current Method	Proposed Method
Timeframe	Full NWA lifetime	10-year deferral period
Ownership Model	Utility ownership	Utility ownership or third-party load reduction contract
Load Reduction Requirement	Exact MWh of load at risk on peak day	Peak output for the duration of the risk
Stacked Values	No stacked values included	Additional stacked values included
Prorated Values	No pro-rating; full values included	Values prorated for just the load reduction period (ARR split)
Solar Performance	PVWatts TMY simulation for one location in Minnesota	PVWatts TMY simulation for multiple locations in Minnesota

We discuss each of these key aspects in more detail below:

Timeframe and Ownership Model. Within the current NWA screening process, the full lifetime of the NWA is considered. This assumes utility ownership, maintenance, and operation of the NWA solution. In the proposed methodology, we solve the risk for a 10-year deferral period and also perform the cost-benefit screening based on this 10-year deferral period – not the full NWA useful life. This aligns the cost-benefit screening process with how we currently expect to structure potential NWA load reduction contracts in the future. This also has the effect of improving the cost-benefit screening performance of potential NWA projects. Within this framework, we assume a contracted load reduction level, with the possibility to work with either a third-party or utility ownership.

Load Reduction Requirements. In the current methodology, NWA risk is viewed as an exact MW and MWh need based on peak day loading. In the proposed method, NWA risks are viewed as full peak output for the duration of the risk. This enables the Company to account for uncertainties in the forecasted load shape. This approach to load reduction is consistent with NWA load reduction contract structures seen in the industry. Figure 3 below illustrates the current load reduction approach in blue, with the proposed load reduction method in red at the bottom.

Figure 3: Load Reduction Requirement



Stacked Values. Within the initial cost-benefit screening, we conduct a comprehensive assessment, where we analyze market inputs and develop stacked values with the resulting data. Some stacked values that we consider in this stage include the following, as defined in the National Standards Practice Manual:

- Avoided Energy Generation
- Avoided Generation Capacity + MISO Reserves
- Avoided Transmission Capacity
- Avoided Transmission Losses
- Avoided Distribution Capacity
- Program Administration
- Interconnection Fees
- Avoided GHG Emissions + Other Environmental

For projects with reasonable cost-benefit results, we begin to consider more stacked benefits when conducting the detailed study – also as defined in the National Standards Practice Manual:

- Avoided Distribution System Losses
- Avoided Distribution System O&M
- Distribution System Voltage

- Credit and Collection
- Risk – Utility/Host Customer
- Reliability – Utility/Host Customer
- Resilience – Utility/Host Customer
- Host Customer Non-Energy Impacts
- Resilience – Societal
- Economic & Jobs
- Public Health
- Low-Income Societal
- Energy Security

We also note that where practicable and applicable, we quantified a particular stacked benefit based on existing valuation methods (e.g., Value of Solar, Integrated Resource Planning).

Prorating Values. This means, prorating NWA costs and stacked values proportional to the fraction of NWA output that solves the system risk. For example, consider a 1 MW solar installation that produces 2,000 MWh annually, but only 400 MWh throughout the year are during the needed load reduction period. In this case, costs and benefits would prorate to 20 percent of the total to reflect the portion of the NWA necessary to solve the risk and defer the traditional solution. This structure reflects NWA approaches at other utilities and allows NWA providers to leverage projects for other needs or uses cases outside of the load reduction period.

Solar Performance. In the current methodology, PVWatts TMY simulation results for one location in Minnesota are used as a representation of solar performance in all projects analyzed in Minnesota. Our proposed methodology expands this to use PVWatts TMY simulation results for multiple locations in Minnesota to allow for more accurate simulations based on the geographic location of the project being studied.

2. *Comparison of Current to Proposed Cost Screening*

Taking the above stacked values into consideration, the cost screening formula evolves into an incremental net impact in the proposed NWA methodology. In the current methodology, an NWA solution's cost-effectiveness is determined by as shown in Figure 4. We note that in the current process, an NWA would be considered more cost effective than the traditional solution if the cost benefit ratio is *less than 1.0*.

Figure 4: NWA Cost-Effectiveness Calculation – Current Methodology

$$Cost\ Ratio = \frac{Total\ NWA\ Cost}{Traditional\ Solution\ Cost}$$

In the proposed methodology, an NWA solution's cost effectiveness is viewed in terms of its incremental costs and benefits. When incremental net impact is less than zero, the NWA is cost-effective. Below is the calculation for our proposed methodology.

Figure 5: NWA Cost-Effectiveness Calculation – Proposed Methodology

$$Incremental\ Net\ Impact = Incremental\ Costs - Incremental\ Benefits$$

We believe an illustrating the differences between the current and proposed NWA methodologies by using an actual project as an example helps explain the application of the formulas and concepts above. In this example, a traditional solution addresses three feeder N-1 risks and one feeder N-0 risk by installing a new feeder and transferring load. The cost estimate for this traditional solution is $4.1 million.

When approaching this project from the current methodology, the magnitude of the overload of each individual risk resolved by the traditional solution is assessed. NWA solutions are constructed for each risk and selected based on cost effectiveness. For this example, optimal energy storage placement can mitigate multiple risks, cutting total costs for the NWA. Table 4 below illustrates overloads for this traditional solution. We note that this chart correlates with the Viking project that we analyzed as part of our 2021 NWA analysis as detailed in Attachment L.

Table 4: Current Methodology Cost Summary for Install Viking VKG Feeder

Capacity Risk	Overload Magnitude			Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	7.55	49.95	0.00	2.9	1.60	7.55/49.95	$17,973,715
N-1 FDR RISK 2	2.40	11.85	Mitigated with optimal energy storage placement				
N-0 FDR RISK 1	0.35	0.84	Mitigated with optimal energy storage placement				
Total			0.00	2.9	1.60	7.55/49.95	$17,973,715

With a traditional solution cost of $4.1 million and an NWA solution of $18.0 million, the cost-effectiveness of this project is:

Figure 6: Cost Effectiveness Calculation – Current Methodology

$$Cost\ Ratio = \frac{\$18{,}000{,}000}{\$4{,}100{,}000} = 4.39$$

Based on our current methodology, this project is not considered to be cost-effective because the cost ratio is greater than 1.0.

When we assess the same project using our proposed NWA methodology, the cost-effectiveness changes significantly. Table 5 below details the incremental net impact utilizing our proposed methodology:

Table 5: Proposed Methodology Cost Summary for Install Viking VKG Feeder

Capacity Risk	Overload Magnitude			Optimal DER Solution			Estimated Net Impact
	MW Overload	Overload Duration (Hours)	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)	
N-1 FDR RISK 1	7.95	13	0	2.9	15.0	8.6/82.7	$1,712,000
N-1 FDR RISK 2	2.45	9	Mitigated by optimal battery placement				
N-0 FDR RISK 1	0.40	4	Mitigated by optimal battery placement				
Total			0	2.9	15.0	8.6/82.7	$1,712,000

In our proposed methodology, the stacked values applied to the project are shown in detail in Table 6 below. We also outline our assumptions and calculations of the stacked values in part C below.

Table 6: Stacked Values (millions)

Impact Name	Cost/Benefit	Value
Avoided Energy Generation	Benefit	-$1.45
Avoided Generation Capacity and MISO Reserves	Benefit	-$0.88
Avoided Transmission Capacity	Benefit	-$0.04
Deferral Benefit	Benefit	-$1.31
Solar Cost	Cost	$1.78
Battery Cost	Cost	$4.86
Interconnection Fees	Cost	$0.03
Avoided Greenhouse Gas Emissions and Other Environmental Impacts	Benefit	-$1.28
	Incremental Benefit	-$4.95
	Incremental Cost	$6.67
	Incremental Net Impact	$1.72

With an incremental cost of $6.67 million and an incremental benefit of $4.95 million, the cost effectiveness of this project is:

Figure 7: Cost-Effectiveness Calculation – Proposed Methodology

$$Incremental\ Net\ Impact = \$6.67M - \$4.95M = \$1.72M$$

This project is not cost-effective due to the incremental net impact being greater than zero. However, as seen in this example, the application of stacked values and changes in our methodology results in a considerable improvement to how the NWA project fares in relation to a traditional utility solution.

C. Stacked Values Assumptions and Calculations

Table 7: Global Assumptions

Assumption	Value	Source/Basis
Deferral Period	10	Currently expected structure of potential future NWA load reduction contracts
Inflation Rate	2%	Current Integrated Resource Plan
Discount Rate (weighted average cost of capital (WACC)	6.47%	Current Integrated Resource Plan
Year 1	2025	
Year 1 Annual Average On Peak Marginal Energy Cost	$21.52/MWh	Value of Solar
Year 1 Annual Average Off Peak Marginal Energy Cost	$14.68/MWh	Value of Solar
Battery Roundtrip Efficiency	85%	2020 NREL ATB
Year 1 Surplus Capacity Credit	$53,633/MW	Current Integrated Resource Plan
Year 1 PPA Cost	$36.29/MWh	2020 NREL ATB
Battery Energy Cost	$223,000/MWh	2020 NREL ATB
Battery Power Cost	$405,000/MW	2020 NREL ATB
Battery Useful Lifetime	15 years	2020 NREL ATB
Average Interconnection Study Cost	$13,000	Estimated from fee schedule in interconnection process
Levelized Avoided Emissions Benefit	$35/MWh	Value of Solar
Year 1 Transmission Capacity Credit	$2,485/MW	Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plans (Docket No. E999/CIP-16-541, September 29, 2017 Decision)
Transmission System Losses	96%	Current Integrated Resource Plan

Table 8: Project-Specific Values

Assumption	Value	Source/Basis
Year 1 Traditional Solution Cost	$3.764 million	Estimated value based on project scope and historical averages
Load Reduction Need #1	• 4.83 MW • 13 hours per day • 5 days per week (weekdays only) • 4 months per year	Estimated load reduction need based on forecast project risks
Load Reduction Need #2	• 3.12 MW • 9 hours per day • 5 days per week (weekdays only) • 4 months per year	Estimated load reduction need based on forecast project risks
NWA Demand Rating	7.95 MW	Estimated load reduction need based on forecast project risks
PV Rating	15 MW	Estimated optimal value
Battery Storage Capacity	82.7 MWh	Estimated optimal value
Battery Power Capacity	8.6 MW	Estimated optimal value
PV Annual Output During Load Reduction Period	6,073 MWh	Estimated based on NREL PVWatts simulation
PV Annual Output	26,984 MWh	Estimated based on NREL PVWatts simulation
Battery Annual Output During Load Reduction Period	6,322 MWh	Estimated based on one complete cycle per day
Battery Annual Output	26,553 MWh	Estimated based on one complete cycle per day
NWA Annual Output During Load Reduction Period	12,395 MWh	Battery and PV output
NWA Annual Output	53,537 MWh	Battery and PV output
Number of Interconnection Points	2	Estimated NWA scope

Figure 8: Calculation – Avoided Energy Generation (Benefit)

$$\begin{aligned}&\mathit{Avoided\ Energy\ Generation}\ [\$]\\ &\quad = \mathit{PV\ Avoided\ Energy\ Generation}\ [\$] + \mathit{Battery\ Avoided\ Energy\ Generation}\ [\$]\end{aligned}$$

Figure 9: Calculation – PV Avoided Energy Generation (Benefit)

$$PV\ Avoided\ Energy\ Generation\ [\$] = \sum_{y=1}^{Deferral\ Period} PV\ Annual\ Output\ During\ Load\ Reduction\ Period\ [MWh] * Year\ 1\ Annual\ Average\ On\ Peak\ Marginal\ Energy\ Cost\ [\$/MWh] / \text{Transmission System Losses } [\%] * \left(\frac{1 + Inflation\ Rate}{1 + Discount\ Rate}\right)^{y}$$

Figure 10: Calculation – Battery Avoided Energy Generation (Benefit)

$$Battery\ Avoided\ Energy\ Generation\ [\$] = \sum_{y=1}^{Deferral\ Period} Battery\ Annual\ Output\ During\ Load\ Reduction\ Period\ [MWh] * \left(Year\ 1\ Annual\ Average\ On\ Peak\ Marginal\ Energy\ Cost\ [\$/MWh] - \frac{Year\ 1\ Annual\ Average\ Off\ Peak\ Marginal\ Energy\ Cost\ [\$/MWh]}{Battery\ Roundtrip\ Efficiency\ [\%]}\right) / \text{Transmission System Losses } [\%] * \left(\frac{1 + Inflation\ Rate}{1 + Discount\ Rate}\right)^{y}$$

Figure 11: Calculation – Avoided Generation Capacity and MISO Reserves (Benefit)

$$Avoided\ Generation\ Capacity\ and\ MISO\ Reserves\ [\$] = \sum_{y=1}^{Deferral\ Period} NWA\ Demand\ Rating\ [MW] * Year\ 1\ Surplus\ Capacity\ Credit\ [\$/MW] / \text{Transmission System Losses } [\%] * \frac{NWA\ Annual\ Output\ During\ Load\ Reduction\ Period\ [MWh]}{NWA\ Annual\ Output\ [MWh]} * \left(\frac{1 + Inflation\ Rate}{1 + Discount\ Rate}\right)^{y}$$

Figure 12: Calculation – Avoided Transmission Capacity (Benefit)

$$
\begin{aligned}
&\mathit{Avoided\ Transmission\ Capacity}\ [\$] \\
&\quad = \sum_{y=1}^{\mathit{Deferral\ Period}} \mathit{NWA\ Demand\ Rating}\ [MW] \\
&\quad * \mathit{Year}\ 1\ \mathit{Transmission\ Capacity\ Credit}\ [\$/MW] \\
&\quad / \text{ Transmission System Losses [\%]} \\
&\quad * \frac{\mathit{NWA\ Output\ During\ Load\ Reduction\ Period}\ [MWh]}{\mathit{NWA\ Annual\ Output}\ [MWh]} * \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{y}
\end{aligned}
$$

Figure 13: Calculation – Deferral Benefit (Benefit)

$$
\mathit{Deferral\ Benefit}\ [\$] = \mathit{Year}\ 1\ \mathit{Traditional\ Solution\ Cost}[\$] * \left(1 - \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{10}\right)
$$

Figure 14: Calculation – Solar Cost (Cost)

$$
\begin{aligned}
\mathit{Solar\ Cost}\ [\$] = &\sum_{y=1}^{\mathit{Deferral\ Period}\ [years]} \mathit{PV\ Annual\ Output\ During\ Load\ Reduction\ Period}\ [MWh] \\
&* \mathit{Year}\ 1\ \mathit{PPA\ Cost}\ [\$/MWh]\ * \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{y}
\end{aligned}
$$

Figure 15: Calculation – Battery Cost (Cost)

$$
\begin{aligned}
&\mathit{Battery\ Cost}\ [\$] \\
&\quad = (\mathit{Battery\ Storage\ Capacity}\ [MWh] * \ \mathit{Battery\ Energy\ Cost}\ [\$/MWh] \\
&\quad + \ \mathit{Battery\ Power\ Capacity}\ [MW] * \ \mathit{Battery\ Power\ Cost}\ [\$/MWh] \\
&\quad + \ \mathit{Battery\ Power\ Constant}\ [\$]) \\
&\quad * \frac{\mathit{Battery\ Annual\ Output\ During\ Load\ Reduction\ Period}\ [MWh]}{\mathit{Battery\ Annual\ Output}\ [MWh]} \\
&\quad * \frac{\mathit{Load\ Deferral\ Timeframe}\ [years]}{\mathit{Battery\ Useful\ Lifetime}\ [years]}
\end{aligned}
$$

Figure 16: Calculation – Interconnection Fees (Cost)

$$\begin{aligned}&Interconnection\ Fees\ [\$]\\&\quad = Number\ of\ Interconnection\ Points * Average\ Interconnection\ Study\ Cost\ [\$]\end{aligned}$$

Figure 17: Calculation – Avoided GHG and Other Avoided Environmental Impacts (Benefit)

$$\begin{aligned}&Avoided\ Greenhouse\ Gas\ Emissions\ and\ Other\ Avoided\ Environmental\ Impacts\ [\$]\\&\quad = PV\ Annual\ Output\ During\ Load\ Reduction\ Period\ [MWh]\\&\quad * Levelized\ Avoided\ Emissions\ Benefit\ [\$/MWh] * Deferral\ Period\ [years]\end{aligned}$$

D. Summary

In summary, we appreciate the input and engagement of stakeholders in examining and offering feedback on our current and proposed NWA analysis methodologies. The stakeholder process and industry NWA evolution and tools shaped the proposed methodology we propose to begin using with our 2022 NWA analysis. We believe the approach, stacked values, and the cost screening changes we have outlined are a reasonable and practicable way to assess whether an NWA will cost-effectively defer a distribution upgrade.

APPENDIX G: DISTRIBUTED INTELLIGENCE CERTIFICATION REQUEST

I. INTRODUCTION

Northern States Power, doing business as Xcel Energy, requests certification – pursuant to Minn. Stat. § 216B.2425 – for its investments in and development of the Distributed Intelligence (DI) capabilities of its new electric meters. Specifically, the Company is seeking certification for the foundational capabilities necessary to use DI and the deployment of its first wave of uses for DI. As discussed in the Company's 2019 Integrated Distribution Plan (IDP), the meters being installed for the Company's Advanced Metering Infrastructure (AMI) initiative are equipped with DI technology.[1] To realize the full potential of our new AMI meters, we need to make additional investments to support the DI components of the meters, and we are now seeking certification for such investments.

The Riva 4.2 meter the Company selected through a competitive process to replace our aging meter infrastructure is manufactured by Itron Inc. (Itron) and has cutting edge DI capabilities. Essentially, each meter contains the equivalent of a small computer that can process data in real time at the meter – harnessing powerful capabilities that will support applications that can help customers better understand and reduce energy usage, and help the Company detect and respond to issues on the distribution system in a way that AMI meters without DI capabilities cannot. On-meter computation is necessary to unlock these advances because practical limitations on bandwidth otherwise make processing of second and sub-second data from hundreds of thousands of meters infeasible.

Xcel Energy is now in the process of developing the physical and information technology (IT) infrastructure necessary to leverage the meter's DI capabilities, focusing on use cases that align with our strategic priorities to lead the clean energy transition, enhance the customer experience, and keep customer bills low. We plan to begin with the DI capabilities that will improve our understanding of the distribution grid and enhance customers' access to information regarding their energy consumption. We anticipate that developing these initial DI use cases will not only maximize early benefits of the meters for our customers, but will also provide the Company with knowledge and experience that will allow us to further realize the capabilities of this emerging technology.

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[1] AMI is a component of the Company's grid modernization plan, which the Minnesota Public Utilities Commission certified as an outcome of the Company's 2019 IDP.

Our first wave of DI uses include three initial customer-facing uses and three initial grid-facing uses. On the customer side, our initial uses are HAN connectivity, energy analysis, and EV detection. These involve connecting to customers and providing them useful information regarding their energy usage via applications on their mobile devices, which will connect to the meter using Wi-Fi. On the grid side, the first use cases, secondary equipment assurance, meter bypass theft detection, and connectivity, will help us to detect and resolve potential problems on the distribution grid and improve the geospatial mapping of our secondary system, which will improve our system modelling and hosting capacity analysis. Ultimately, we will build upon these initial capabilities and we expect DI to help the Company and our customers unlock benefits of grid-modernization beginning in the next few years and continuing for the following decade.

As the Company marches toward our vision of an 80 percent reduction in carbon emissions by 2030 and 100 percent carbon-free electricity by 2050, DI is among the tools that will facilitate our progress. The analytics made possible through DI have the potential to make customers more than just consumers of energy – giving them the capabilities and information to be active participants in their energy usage. With detailed information, customers can change their behavior in ways that promote energy efficiency and demand response, saving on energy bills while also providing benefits to all customers through grid benefits and carbon reductions. Similarly, DI analytics will extend the Company's advanced capabilities for the distribution system to enable more precise monitoring and control at the edge of the grid, enabling greater reliability and lower costs to customers for managing the system.

Section II begins by providing background regarding the related ADMS, AMI, and FAN projects. Section III then discusses the standards for certification under the Minnesota statutes and Commission precedent. Section IV provides an explanation of DI, describes the DI capabilities of the Riva 4.2 meter, and discusses the benefits of DI in general terms. We then move on to our plans to deploy DI in Section V, including our investments in foundational DI capabilities, the customer and grid-facing use cases (and potential future uses of DI that may build upon those initial uses), and our budget. In Section VI, we discuss data security and data access. Then, we explain how our DI foundational capabilities and initial use cases satisfy the standards for certification in Section VII before concluding in Section VIII.

II. BACKROUND

Since 2015—and consistent with the legislature's amendment of Minn. Stat. § 216B.2425 that same year to allow for the certification of distribution modernization projects—the Company has been in the process of modernizing our distribution system, moving to one in which both the Company and our customers have deeper insights into their energy usage and are able to take actions to optimize that usage and the integration of distributed energy resources (DER). In 2015, we sought certification for our Advanced Distribution Management System in our first Grid Modernization Biennial Report,[2] which the Commission granted the following year.[3] In our 2019 IDP, we sought certification for AMI and the Field Area Network (FAN),[4] and the Commission granted both requests on July 23, 2020.[5] This year, our ADMS control centers went live and the ADMS system has performed well. Installation of the new AMI meters begins in 2022 and FAN installation is underway with the installation of 123 of the 201 network devices needed for the 2022 meter deployment.

In our 2019 IDP, in connection with our request for certification for AMI, we discussed the potential DI capabilities of the AMI meters we had chosen, stating:

> [T]he AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and will be updated with new software applications, much like customers can currently update their mobile devices with applications.[6]

In its July 23, 2020 Order granting certification, the Commission stated:

> [b]eing able to see load in real time, understand their impact, and shape or shift load through advanced rates and other demand response methods can help reduce system costs and give customers more control over their energy consumption.[7]

In our application for AMI certification, we also explained that the advanced capabilities of the new meters "would be phased in over the next several years," and that we were sequencing our investments so as to preserve our flexibility to adapt to the evolving customer and technological landscape.[8] Now, as we are beginning the

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[2] *In the Matter of Xcel Energy's 2015 Minnesota Biennial Transmission & Distribution Projects Report*, Docket E999/M-15-439, Grid Modernization Report (Oct. 30, 2015) at 11-15.
[3] *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, Docket E-002/M-15-962, Order Certifying Advanced Distribution Management System (ADMS) Project Under Minn. Stat. §216B.2425 and Requiring Distribution Study (June 28, 2016).
[4] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket E-002/M-19-666, Integrated Distribution Plan (Nov. 1, 2019).
[5] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects (July 23, 2020).
[6] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket E-002/M-19-666, Integrated Distribution Plan (Nov. 1, 2019) at 8.
[7] *Id.* at 15.
[8] *Id.* at 173, 176.

installation of AMI meters across our service territories, we are taking the next step in phasing in the advanced capabilities of the meters, and are seeking certification of investments we will be making to begin taking advantage of the DI capabilities of the AMI meters.

As we discuss further below, to realize the benefits of DI, there must be backend physical infrastructure, such as additional hardware and data center space, IT architecture, and developed and deployable uses for DI capabilities. Since our last IDP, we have been studying the technology and developing our plans for DI. Now, we are putting in place the physical, organizational, and architectural infrastructure for DI, including developing initial uses of DI that will provide value while also facilitating future uses of the technology that are more complex.

III. CERTIFICATION STANDARDS

In 2015, the Minnesota legislature amended subdivisions 2 and 3 of Section 216B.2425 of the Minnesota Statutes, to provide for the certification of grid modernization transmission and distribution projects proposed by utilities, and at the same time, amended Section 216B.16, subd. 7b, to allow the timely recovery of prudently incurred costs of certified projects through the Transmission Cost Recovery (TCR) Rider. Accordingly, if development of the foundational architecture and infrastructure for DI and deployment of the first wave of DI applications is certified by the Commission, Xcel Energy will be able to subsequently seek recovery of those DI project costs through the TCR. We note that the Commission has previously clarified that "certification does not constitute a pre-judgment of whether costs will be recovered through riders or base rates. Certification simply permits a utility to request rider recovery in the future, which the Commission may approve or deny based on the facts available at the time."[9]

The legislature has not established specific criteria for the Commission to apply in making certification determinations, and the Commission indicated in 2016 that certification decisions would be made on a case-by-case basis with more detailed criteria being developed over time, if necessary, as the Commission gains more experience with grid modernization.[10] Subsequently, in a 2018 Order, the

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[9] *Id.* at 17.

[10] *In the Matter of Xcel Energy's 2015 Biennial Distribution-Grid-Modernization Report*, Docket E-002/M-15-962, Order Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. § 216B.2425 and Requiring Distribution Study (June 28, 2016) at 9.

Commission listed the following factors for the Company to address when requesting certification:

i. details on why the project is necessary for grid modernization;
ii. how it is in the public interest;
iii. how it is consistent with the Commission's Guiding Principles for Grid Modernization (Docket 15-556);
iv. the intended objectives for the project;
v. a description of the available alternatives to meet the intended objectives;
vi. a cost benefit analysis of the project; and
vii. potential interrelation with other initiatives, projects, and Xcel's long-term grid modernization plans.[11]

The Commission's Guiding Principles for Grid Modernization, which are referenced in item (iii) from the list above are:

i. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
ii. Enable greater customer engagement, empowerment, and options for energy services;
iii. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
iv. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
v. Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.[12]

While these criteria are not definitive and the Company anticipates that the Commission will continue to engage in a flexible, case-by-case analysis, they do provide useful guidance regarding issues relevant to the Commission's consideration of this certification application. Accordingly, this application uses a discussion of the factors listed above, including the Guiding Principles for Grid Modernization, to demonstrate that our project to enable and develop the DI capabilities of the new AMI meters should be certified.

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[11] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program* and *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report*, Dockets E-002/M-17-775 and E-002/M-17-776, Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request (Aug. 7, 2018) at 9.

[12] *In the Matter of the Commission Investigation on Grid Modernization*, E-999/M-CI-15-556, Staff Report on Grid Modernization, (Mar. 2016) at 14.

IV. DISTRIBUTED INTELLIGENCE

Xcel Energy is seeking certification for our development of the foundational capabilities of DI, including the deployment of the first wave of customer and grid-facing solutions using DI. As an initial matter, however, we explain DI.

A. Definition of DI

DI, or "distributed intelligence" involves the "distribution" of computer processing and analytics to localized devices and platforms. It is also sometimes referred to as "edge computing" or "grid-edge computing." As a general matter, DI can involve the distribution of computer power and analytics to any sort of localized "smart device." Such devices are becoming more common (they are sometimes referred to as the "Internet of Things" or "IOT") – and DI, in this broad sense, could conceivably have advantages in a variety of industries and areas of life. However, the specific form of DI that is the subject of this application involves the Company's new AMI meters. Each individual meter will have computer processing capabilities, and the individual meters will not only communicate with Xcel Energy's larger IT infrastructure, but are also able to communicate with each other using "peer to peer" communication, which is an important component of the Company's overall DI plans. Using software specifically developed for a purpose, commonly referred to as "applications" or "agents," the Company will be able to carry out some computer processing on the meters, which allows for a localized analysis of the data collected by the meters.

DI is a new and innovative technology for electric utilities. We are aware that Tampa Electric Company has installed DI-capable meters and is deploying some grid-facing DI applications; however, they appear to be the only peer utility within the United States to have done so thus far. Xcel Energy is, therefore, one of the pioneers in this area, and we were able to use that status to negotiate favorable terms for the purchase of the DI-capable meters.

B. Capabilities of the Meter Chosen by Xcel Energy

The AMI meter Xcel Energy has selected and will be installing in Minnesota between 2022 and 2024 is the Riva 4.2 meter manufactured by Itron. The Riva 4.2 is equipped with the computer hardware necessary to allow DI capabilities, but was priced similar to AMI meters without DI capabilities. The Company was, as a result, able to purchase DI-capable meters without additional cost. **[PROTECTED DATA BEGINS**

PROTECTED DAT ENDS] has a computer processor, 2GB of flash memory, and random access memory (RAM). The meters each come pre-loaded with the Linux operating system. Figure 1 below shows the Riva 4.2 meter's external appearance.

Figure 1: The Itron Riva 4.2 Meter

The Itron Riva 4.2 also contains components allowing for multiple communication methods. Each meter contains a Wi-Fi radio that can be used to communicate with the Company's field technicians and a customer's Home Area Network (HAN), a two-way mesh radio that allows for communication with other meters and the Company's backend systems via the FAN, and a Power Line Carrier device that allows for communication through the distribution conductors.

To take advantage of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** and its capabilities, however, the Company must make the foundational investments discussed below. Without these, the foundational DI capabilities cannot be developed and DI use cases cannot be deployed. In that case, the Riva 4.2 meters would have the more limited functionality of non-DI AMI meters. The meters would, for example, measure voltage and current and could provide meter reads at set intervals or on-demand via the FAN and automatically notify the Company if a customer's power goes out – but communication to customer devices via the HAN would not be possible, nor would the distributed analysis capabilities that are further described below.

C. Benefits of DI

To understand why DI is an innovative technology and the types of benefits it brings, it is important to contrast DI with the conventional model of computer processing "intelligence." Traditionally, when we and other electric utilities analyze data from meters (and other important system data), we have done so using software that is installed in and running on servers located in data centers. Today, without DI, data comes into the Company's core IT systems, is analyzed, and then actions of some type may be taken based on the results of that processing. The meter reading and billing systems are a classic example of the traditional model. Energy usage data from individual meters is collected (either manually or electronically), and it is transmitted to Company systems where software running on servers located in data centers calculates monthly bill amounts based on that energy usage data and the applicable rates, and customers' bills are generated. The computer "intelligence" used in those processes is not distributed, it is centralized.

Without DI, the energy usage data the Company can analyze (in our data centers) is limited to 5 or 15-minute interval energy usage information. While 5 or 15-minute interval data is an improvement on what was available from earlier meters, it is not as granular as the data that can be analyzed using DI.

With DI, some computer processing occurs on the meters themselves. The Company will still have and need its core IT infrastructure and there will still be centralized processing. DI *augments* those centralized capabilities; it does not replace them. For example, it is still necessary to generate customers' monthly bills using software running on centralized Company servers. However, there will also now be additional processing hardware located at the individual customer homes and businesses to perform localized tasks. This is the "edge" of the distribution grid, which is why DI is sometimes referred to in the utility industry as "grid edge" computing. This opens up new possibilities for implementing software applications that can assist customers in understanding their energy usage and the Company in understanding the performance of the distribution grid.

While AMI meters can be designed and constructed so as to collect data at intervals much shorter than every 5, 15, or 60 minutes, bandwidth limitations have made it impractical for utilities to collect data of that granularity on a broad scale. The FAN, for example, does not have the bandwidth to allow second-by-second (or more granular) data to be transmitted to the Company's IT systems for back-end analysis, and it would be cost prohibitive to construct a communications network with the bandwidth that would allow for transmission of a continuous or nearly continuous flow of data from every meter throughout the system. As a result, there are limits to the Company's ability to analyze data from meters using only its more centralized capabilities.

However, DI creates new possibilities. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] That sub-second data can be analyzed using the meter's own computing capabilities, and then the results of that on-meter analysis, which are less voluminous than the raw metrology data, can be transmitted to the Company's back-end systems and can also be sent to customers via, for example, a mobile application. The transmissions to our back-end systems will take place every 15-minutes. Within the back-end systems, the results of the on-meter analysis may be further analyzed and/or combined with information from other sources. The decentralization of computer processing through DI thus allows us to analyze data from individual meters to a degree that would not otherwise be feasible.

While traditional revenue metering needs are well met with basic AMI interval metering, there are valuable insights for the Company and its customers that can be gleaned from higher-resolution data. Because the quality of the data is more detailed, that improved data can yield better information and ultimately better outcomes. For example, many power quality and reliability issues are best identified through the high-resolution data, which can help identify the cause of voltage flicker or the source of harmonics, as well as better characterize the impacts of system outages and disturbances. The granular data can also be analyzed to learn about energy usage within a customer's home or business, which can provide useful insights for customers regarding their own behaviors and the performance of their appliances and devices.

DI also opens up additional possibilities because of the peer-to-peer (or meter-to-meter) communication capabilities. Adjacent meters will be able to communicate with one another, and the power quality and load information they can share may allow applications running on the meters to better characterize the state of the distribution system and identify potential problems. For example, the Connectivity use case discussed below in Section V.C.3 will use communication between meters to improve our information regarding the secondary system.

V. THE COMPANY'S DI DEPLOYMENT PLANS

In 2019, Xcel Energy began a process to develop an overall DI strategy as follows: (1) taking inventory of DI capabilities and considering use cases; (2) prioritizing use cases based on value to customers or the system and complexity; (3) identifying what we consider core, foundational capabilities to be deployed, and (4) developing a blueprint for bringing the identified DI products to our customers.

As result of that four-step process, we developed a Roadmap for our planned deployment of DI. Following the Roadmap, the Company is now working to develop the foundational capabilities to deploy DI, and will also deploy initial DI use cases; it is these capabilities and use cases that are the subject of this request for certification. The Company's initial use cases will be both customer facing, or those that relate to the use of electricity within the customer's premises, and grid facing, which are the uses of DI that relate to the operation and reliability of the distribution grid. The Company is implementing DI in this sequence because the foundational capabilities are necessary for the initial use cases, and the initial use cases will provide us with the experience and tools to use in later deploying future use cases. As an alternative, the Company could choose to focus initially on only grid-facing uses of DI (as at least one other electric utility is doing); however, we have chosen to deploy both initial customer- and grid-facing use cases because of the forecasted benefits to our customers. Figure 2 below provides an overview of the Roadmap.

Figure 2: DI Roadmap

Distributed Intelligence

Applicability to product and service roadmap

	DAY ONE (2022)	NEAR TERM (2022-2025)	FUTURE (2025+)
ENHANCE THE EXPERIENCE	• Energy Usage Dashboard • Enhanced Web and Mobile Apps • Enhanced Outage Notifications • Green Button Connect My Data	• Emergency and Safety Notifications • Energy Usage Alerts and Notifications • Personalized Notifications • Power Quality Analysis	• Artificial Intelligence Enabled Notifications • Smart Premise Restoration • Smart Safety Disconnect
KEEP BILLS LOW	• Enhanced Communication Options with Behind the Meter Systems (HAN)	• Whole Facility Monitoring • Rate Advisor • Time Varying Rates • Virtual Energy Audits	• Smart Rates • Enhanced Automated Demand Response
CLEAN ENEERGY		• Demand management optimization • Enhanced access to battery storage and electric vehicles • Green notifications and controls • Enhanced DER enablement	• Enhanced DER management and control • Enhanced Microgrid Integration

Enabled or enhanced by Distributed Intelligence

In broad terms, we are beginning by developing foundational functionality, with complexity and analytic capabilities increasing in the future. In addition to providing immediate benefits, our work on the initial planned customer- and grid-facing use cases will also require us to develop analytical capabilities that should enable a wide spectrum of additional use cases. In the future, those additional use cases will extend more granular data and analytics-driven insights to customers and potentially enable customer control and automation in their home or business. Prioritization of these future use cases will be based on insights and knowledge gained from deployment of the foundational solutions. There are two sets of foundational use cases that we are planning to develop and deploy in the near future and for which we are seeking certification: (1) foundational customer-facing solutions, which include customer energy analytics and insights, HAN connectivity, and electric vehicle detection to support existing vehicle programs, and (2) foundational grid-facing solutions, which include secondary equipment assurance, power theft detection, and connectivity.

A. Development of Foundational Capabilities

By the end of 2021, the Company expects to complete foundational capability development to enable the initial use cases described below. Namely, creating the infrastructure and architecture to operate DI, completing testing and development of the initial HAN connectivity capability, testing available grid-facing solutions, along with an associated real-time energy usage mobile application, and exploring load disaggregation capability via both on-meter and back-office analytics. These capabilities create the basis for foundational capabilities to be deployed in 2022 as meters are installed for both the grid and to customers, as discussed below.

The architecture development work involves the creation of the software to effectively, reliably, and securely integrate the DI of the new meters with Xcel Energy's back-office systems. This includes integration with existing meter data and customer information systems, as well as development of the core load analytics capability which unlocks much of the potential for future applications. Infrastructure development consists of data center infrastructure (including servers, storage, and network infrastructure) and other hardware to support DI implementation. The advanced meters themselves contain DI capabilities, but additional hardware is necessary to store data and host those processes that interact with the meters. Use case development consists of software development, conceptual development, and testing.

B. Customer-Facing DI Use Cases

Customer-facing applications are those that provide insights and tools to customers to allow them to better understand and manage their energy usage. These applications leverage the meter's ability to monitor electric usage within the home or business. As with other DI use cases, the meter is used for localized analysis of data collected by the **[PROTECTED DATA BEGINS** **PROTECTED DATA**

ENDS]. The results of the on-meter analyses will be subject to further processing and then shared with the customer via the appropriate communication channel, primarily through a customer web portal or mobile application.

The Company has three categories of customer-facing DI use cases planned for near-future deployment, and, as with grid-facing uses of DI, then plans on implementing more complex uses of DI once it has the benefit of the lessons learned and the analytics derived from those initial uses. The three initial use cases, for which the Company is seeking certification are: (1) HAN connectivity, (2) energy analysis, and (3) electric vehicle detection.

1. HAN Connectivity

This use case involves connecting customers to the meter located on their premises using Wi-Fi. The initial application will allow customers to get kW and kWh reads from the meter using a mobile application offered by the Company and a corresponding DI application running on the meter that communicates with the mobile application using industry standard communication protocols. We expect this capability will initially appeal to our most energy conscious and technological savvy customers.[13] By giving them real-time access to their energy usage, customers will be able to accurately observe and control how they use energy.

The following sample screenshots depict a customer successfully logging-in using the Company's test mobile application and receiving confirmation that the customer's Home Area Network is connected and thus ready to receive information directly from the meter using Wi-Fi.

[13] Research indicates that a broad class of residential customers will be interested in engaging once additional insights, like those offered by the next use case discussed below, are available. The HAN connectivity use case will serve as a building block for that broader engagement.

Figure 3: Sample Customer Login and Connection Screens

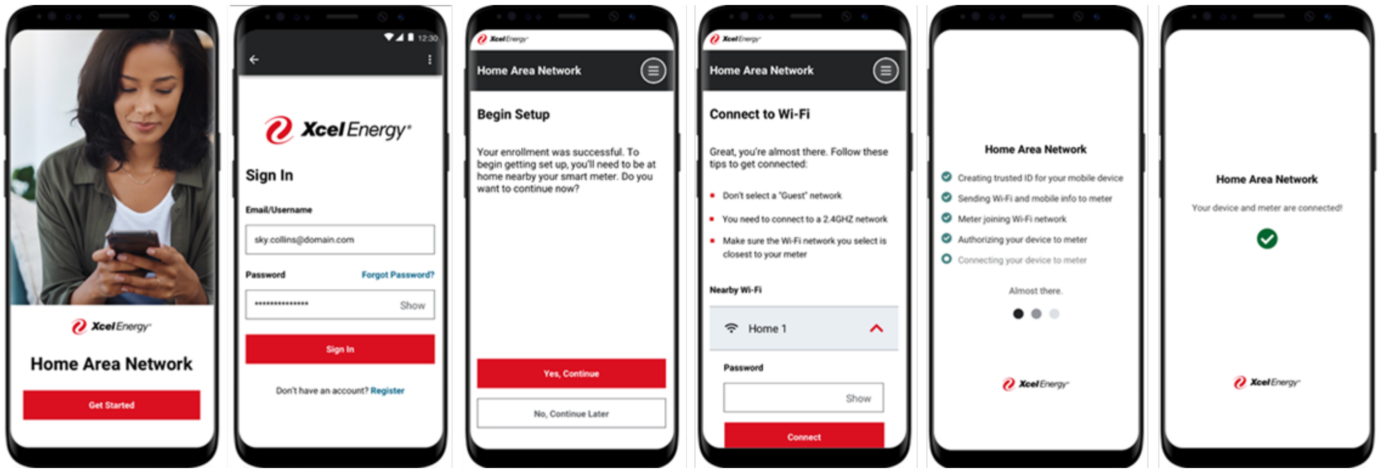
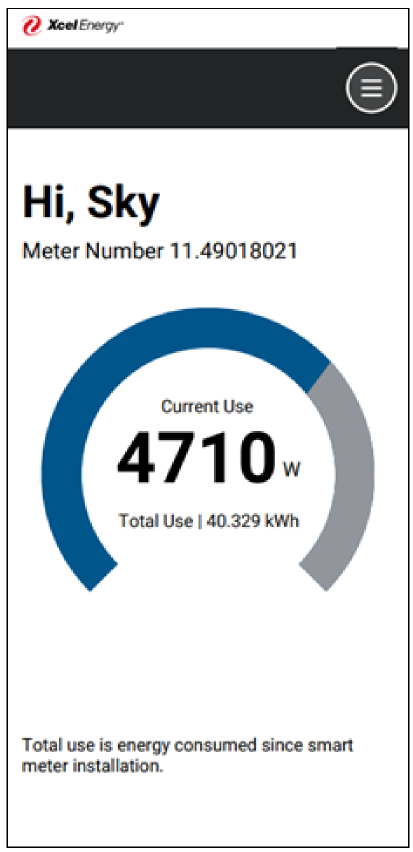


Figure 4: Sample kW and kWh Read



The basic functionality provided by this use case is an important building block. The deployment will give us ability to test internal systems to deploy DI applications and orchestrate the DI ecosystem, including software on the meter, as well as the back-end systems that enable a full solution.

In short, many of the customer-facing use cases, including the energy analysis use case discussed below, require connectivity into the home using Wi-Fi, all of which the HAN connection enables. Given the practical bandwidth limitations of any widescale communications network such as the FAN, it is Wi-Fi that will allow the Company to provide truly real-time information to customers – and it is Wi-Fi that will eventually enable direct communication with a broader array of smart devices.[14]

2. Energy Analysis

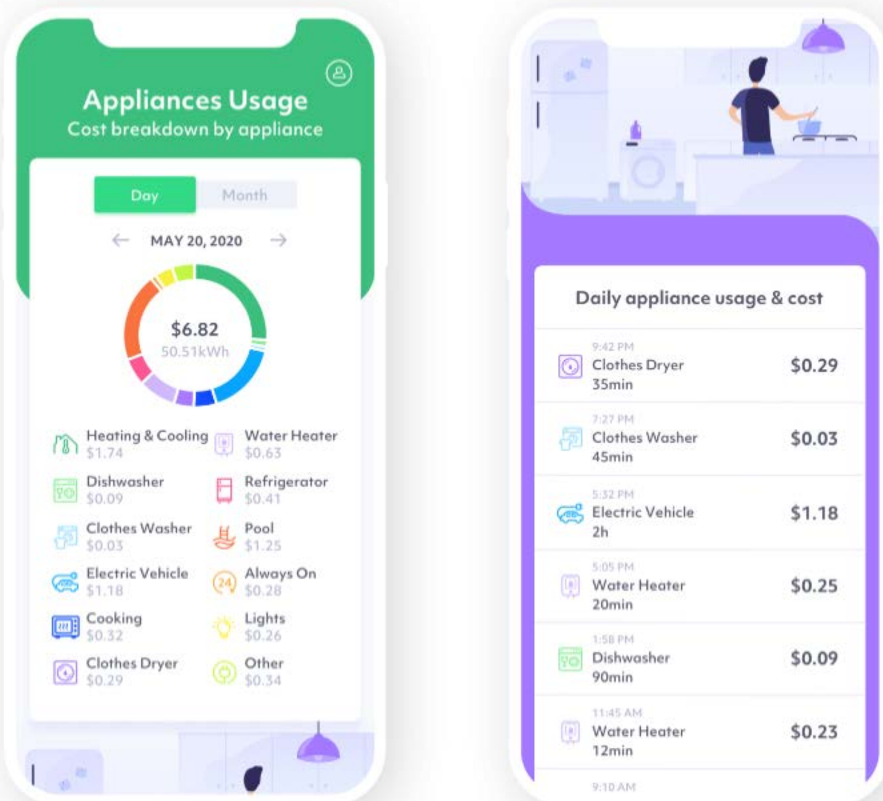
Through focus groups, we have learned that customers often have a misunderstanding of what uses the most energy in their homes and often equate energy saving efforts to "turning the lights off" which, in reality, does not have a particularly significant impact when compared to other possible actions. As a result, customers who want to reduce their energy usage for financial and/or environmental reasons often do not have the information to empower them to make knowledgeable decisions regarding the use of equipment in the home.

Using appliance disaggregation, the energy analysis use case will allow customers to see which appliances use the most energy and how that impacts their monthly utility bills. Sometimes referred to as "nonintrusive load monitoring," appliance disaggregation utilizing DI will involve the analysis of an overall usage signal in order to determine which appliances are in use and estimate the load attributable to each. Individual types of appliances have characteristic features, such as the manner in which they start up, that can be detected by examining second-level and sub-second data available through DI. Crucially, this analysis does not require that customers have smart appliances. Instead, a load disaggregation application running on the meter will perform on-meter analysis of the data gathered by the meter, which, when combined with further back-end processing, can provide reliable and detailed disaggregation information to customers.

After issuing a Request for Proposal (RFP), we are currently in discussions with a vendor who has developed such an application. We anticipate that energy analysis information could be provided to customers via a mobile application. The following sample screenshots depict the type of information that might be provided.

[14] The Company will use the 2030.5 communications protocol promulgated by the Institute of Electrical and Electronics Engineers (IEEE) for communication via the Wi-Fi radio. The 2030.5 protocol can be used for various energy management functions including load control and management of DER.

Figure 5: Conceptual Screenshot for Energy Analysis



The smartphone application, which will directly connect with the meter using Wi-Fi, will provide customers with near real-time disaggregated information regarding their energy usage and notifications designed to prompt changes in energy usage. The notifications and suggestions offered by the smartphone application can encourage the shifting or shedding of load during periods of peak demand. Those customers with smartphones who participate will be empowered to change their energy consumption behavior. The resulting changes in customer behavior will save our customers money on their monthly bills, which is reflected in the cost-benefit analysis presented in Section VII.E. In addition to that direct financial benefit for customers, the change in customer behavior facilitated by the energy analysis use case will also benefit the environment and should lower the Company's costs due to reductions in peak demand. Further, as is discussed below, the capabilities developed by this use case can later be expanded upon to further improve our ability to encourage and incentivize the shedding and shifting of load.

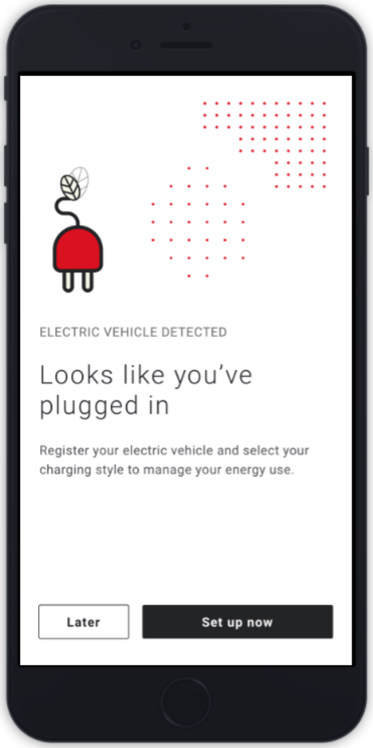
3. *Electric Vehicle Detection*

When a customer first plugs in an electric vehicle (EV) at their premises, an extension of the same technology that enables the energy analysis use case discussed above could also be used to detect the presence of that EV. That can enable several important benefits for both the customer and the Company. From the Company's standpoint, it provides critical information regarding growing EV penetration on the system, allowing us to better manage and plan distribution operations for significant increased load and the resulting changing load dynamics. From the customer's standpoint, EV detection can provide a channel to introduce customers to programs and rates that best suit their budgets and needs. The use of these programs and rates can lower the costs of EV ownership, and thus promote transportation electrification, which has important carbon emission reduction benefits.

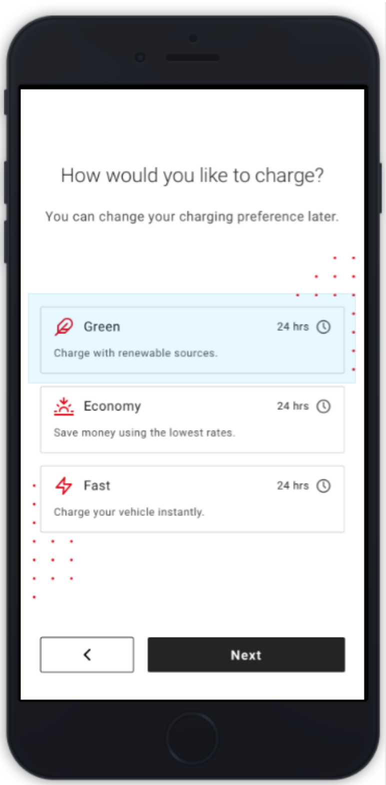
While it is early in conceptual development, the sample screenshot shown below as Figure 6 provides an example of how EV detection might function using a mobile application. EV detection could also be addressed using the same mobile application as energy analysis, which is depicted in the second sample screenshot below, Figure 7.

Figure 6: Conceptual Screenshot for EV Detection

Potential Screen



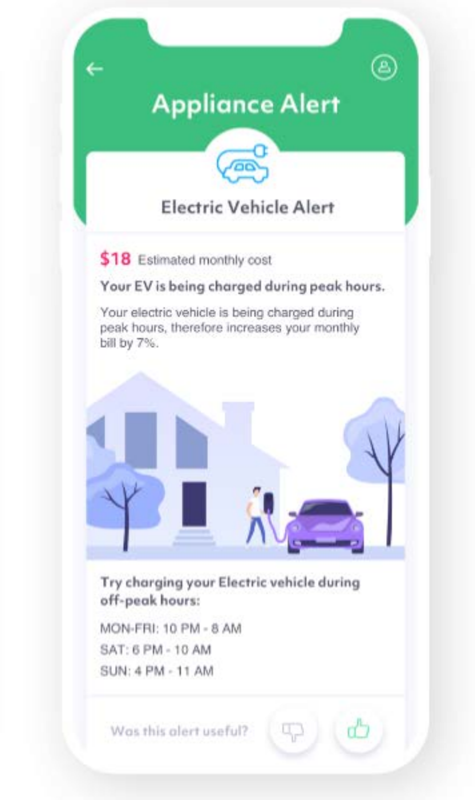
As the EV Detection DI Agent identifies a potential EV is plugged in, a notification would bring the customer to a mobile application page requesting them to "set up" their electric vehicle with Xcel Energy.



On a subsequent page, the customer could select their charging preferences, which would inform service and rate selections that would help the customer meet their goals.

Over time, EV detection could also function in the context of an energy analysis application, as shown in the conceptual sample screenshot below.

Figure 7: Conceptual Screenshot for EV in Energy Analysis



Our customers will benefit because EV detection will help them find the right rates and programs for their budgets and needs. Also, when applicable, it will encourage vehicle charging during periods when rates are lower. By keeping EV ownership costs lower, we will be promoting transportation electrification, which has carbon emission reduction benefits. In addition, there is grid-facing benefit to EV detection, as it will encourage charging during off-peak periods and will provide information regarding the prevalence and location of EVs.

4. Future Use Cases

While the Company is seeking certification for deployment of the use cases discussed above, we also plan to explore and, as appropriate, further the development of additional customer-facing applications. The experience the Company gains from deploying initial applications and, in some cases, the analytical capabilities of those initial applications will facilitate future use cases. Various potential applications are under conceptual development, and we are particularly interested in the following categories:

Enhanced Behind the Meter Connectivity via HAN. We expect residential customers, in particular, will engage with our initial offering of real-time usage and demand data via the mobile application. However, different solutions may be required in order to create the most value for customers with more sophisticated energy management capabilities and technologies. Over time, these offerings may expand into using on-meter applications (in conjunction with back-end processes) and the meter's Wi-Fi radio for direct demand management or demand response offerings.

Energy Insights. Building off the disaggregation capability from the initial energy analysis use case, a variety of additional features and capabilities can be implemented. Based on initial customer feedback, additional features may include personalized savings tips, appliance health alerts, and behavioral demand response. These expanded capabilities can further encourage and incentivize load shedding and load shifting behaviors.

Expanded Electric Vehicles Functionality. We anticipate expanding upon the initial EV use case by providing personalized savings tips, increased charging analytics, and potentially expanding into managed EV options.

Safety and Security. There are a variety of potential safety and security applications that may be developed that in many ways rely on the foundational capabilities described in this certification request, including responding to unusual usage patterns, and alerting customers to home wiring issues.

C. Grid-Facing DI

Grid-facing applications will provide insights to Xcel Energy to better plan and more effectively operate the system. These applications leverage the meter's ability to function as an edge-of-grid sensor, monitoring the system's performance all the way to the customer's service at the very edge of the secondary voltage portion of the system. As with other DI use cases, the meter is used for localized analysis of data collected by the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, and the results of those analyses can then be shared with the Company's back-end systems and/or other meters in the vicinity.

There are three fundamental types of grid-facing applications:

- Applications that gather data for analysis (e.g., connectivity);

- Applications that provide notification by exception (e.g., secondary equipment assurance, meter bypass detection); and,
- Applications that provide for local control.

The Company's initial planned deployments, for which it is seeking certification, fit into the first two categories. The DI applications for our initial grid-facing use cases have already been developed by Itron and are available for deployment. Our approach to grid-facing DI is to begin with applications that have already been developed and are available for purchase, and then continue to develop and deploy progressively more complex applications which will provide progressively more valuable insights.

1. Secondary Equipment Assurance

Secondary conductors carry power between the Company's distribution transformer and customers' meters. Our system in Minnesota has nearly 980,000 secondary conductors. When problems arise with the secondary conductors, the result can be outages, partial outages, and voltage fluctuations which disrupt our customers' homes and businesses and can lead, in some instances, to customer equipment malfunction.

Historically, it was not feasible for utilities to monitor this portion of the grid. There are simply too many individual conductors, and it would be cost prohibitive to install monitoring devices on all of them or even a substantial subset. Instead, when a problem develops, we often first learn of the issue because a customer notices (for example, lights within a home may be flickering) and then calls and requests assistance. In that example of the flickering lights, we would respond by sending a worker to investigate and, if appropriate, install a temporary recording voltmeter.

AMI meters with DI capability offer, for the first time, a practical solution to this problem. To monitor the secondary portion of the system, we will leverage two DI applications: (1) the High/Low Impedance Detection application, and (2) the Open Secondary Neutral application. Both these applications are designed to proactively identify issues and allow us to solve them before the customer is aware that a problem is developing. Crucially, these are foundational applications, and the algorithms within them form the core computing means for subsequent applications.

High/Low Impedance Detection. This application monitors the health of connections and can detect certain deterioration of the energized conductors. Deteriorating or loose connections, as well as deteriorating conductors, tend to progress to failure over time, at which point the customer will experience a partial or complete outage. But prior to that point, customers can experience voltage fluctuations causing customer complaints due to light flicker or equipment malfunction. However, even if there are flickering lights or other signs of a developing problem, customers may not notice or may not contact Xcel Energy. This application running on the meter can take current and voltage meter data collected by the meter and analyze them to calculate the impedance; then, it can send an alert to our system if the impedance falls outside of a normal range or increases consistently, which are signs that a problem is developing. These alerts will provide early detection that will allow us to resolve issues before they become costly or dangerous. In addition, early detection allows us to resolve issues as part of scheduled maintenance work and can, therefore, eliminate the need for a field crew to be immediately dispatched in an outage situation, which ultimately will save O&M costs in rates.

While unusual, a high impedance connection in the meter socket or within equipment leading to the socket can generate enough heat to start a fire. High impedance detection, together with the internal temperature monitoring capabilities of our Riva 4.2 meters, will go a long way to further reducing this potential.

In addition, together with Itron, we are exploring the potential to identify and notify the Company if the impedance is too low – a situation that could develop if a transformer size is increased, as may be necessary as more electric vehicles are charging. While we have design guidelines meant to preclude this problem, this application could provide additional assurance.

Open Secondary Neutral. Occasionally, customers may experience an unbalanced voltage problem if a neutral connector opens. When this happens, some lights within a home appear dim, while others are brighter than normal. However, because the home or business continues to have electricity and the damage develops slowly, the problem is often not immediately obvious to the customer. In addition, issues with neutral connectors are difficult to detect and involve intensive manual labor and/or voltage tests. The Open Secondary Neutral application will monitor the system and notify the company if an open neutral is detected, which will allow us to avoid the time and expense associated with manual inspections and proactively resolve problems, thereby reducing customer complaints and damage to their equipment.

The benefits of these grid-facing applications are difficult to quantify with complete certainty; accurate records of these specific problems are not available because the Company has not tracked these specific issues nor had the technology to systematically do so until now. Nevertheless, we estimate that out of the annual average of over 2,750 related service calls per year, approximately 1,000 may be attributable to the equipment issues these applications would identify. Shortening troubleshooting time will provide value, but the highest value will be to customers, as we will be able to rectify most of these issues before customers even notice a problem.

2. Meter Bypass Theft Detection

Diversion – or theft – by meter bypass occurs when a person intentionally alters a meter installation or otherwise bypasses the electrical meter, such that some or all of the power consumed does not pass through the meter and is therefore unbilled. Diversion implicates both safety and financial ramifications. Such action is illegal and is done while equipment is energized, typically by unqualified persons. The bypass work thus puts the person performing it at risk and the result is often a public safety and fire hazard.

Today, the Company typically becomes aware of diversion primarily through identification during site visits, as a result of data analytics, or if someone informs the Company or authorities regarding the bypass. The Company becomes aware of approximately 12 bypass diversions each year. Itron has an application currently available to detect meter bypass diversions. Given that the Company does not have reason to believe that meter bypass diversions are common, the most important benefit of this use case would be to eliminate the public safety hazards created by diversion.

3. Connectivity

Knowing the precise location of the customer's premises and how it is connected to the grid is foundational to the Company's ability to plan and operate our system and to keep our customers better informed regarding outages. The mapping of customers to the system is maintained in our Geospatial Information System (GIS), which forms the basis for all of our system planning, operation, and modeling. Though we believe our current GIS information is fairly good, we also know that gaps do exist – particularly with our secondary system data. These gaps exist because, with prior generations of connectivity model technology and historic use cases for the data, the Company did not have the capabilities nor the need to gather and maintain the scope and precision of system data required for a modern grid. As such, legacy manual mapping sources, which served as the basis of GIS data migration, did not contain secondary asset information or some primary system attributes that now are also needed. Today, however, we need that precision for efficient outage management, automated operations, DER interconnections, and future advanced grid capabilities.

When locations are not correctly mapped, that results in less accurate ADMS solutions, planning models, and hosting capacity calculations. Highly accurate detailed distribution system data is critical to building system models and performing the complex engineering studies necessary to optimally integrate distributed energy resource (DER) generation with the distribution grid. This GIS model is also used by several other functions at Xcel Energy, notably our Outage Management System (OMS). To improve our asset data, the core DI application will leverage the meters' Power Line Carrier (PLC) communication devices to enable the meters to self-identify themselves to each other and form groups that we can compare with distribution transformer groupings, which are mapped in GIS. These comparisons will identify outliers that need correction.

The benefits of grid-facing connectivity use cases are improved accuracy in outage management and notification, and improved accuracy in planning and operational modeling, including ADMS. It will also improve the accuracy with which we analyze potential DER interconnections.[15] This specific application will identify and correct the connectivity to mis-mapped customers, reducing this source of error. All processes that rely on the connectivity model in our GIS, including outage management, will benefit from the improved data. Going forward, this use case can also be used to maintain the accuracy of our GIS mapping after modifications to the secondary system.

4. *Future Use Cases*

While the applications discussed above are currently available for deployment, we also plan to explore and as appropriate, further the development of additional grid-facing applications. Though we are not seeking certification for the future use cases, the development of foundational capabilities and the experience the Company gains from deploying initial applications and, in some cases, the analytical capabilities of those initial applications will facilitate future use cases. Various potential applications are under conceptual development, and the Company is investigating the potential deployment of the following categories of grid-facing DI uses.

DER Hosting Capacity. The connectivity use case will improve our hosting capacity analysis through more accurate GIS data. This potential future use case would take things further by using the meters to identify local (secondary system) limitations to DER (generation, load, and impedance), which could improve the speed and accuracy

[15] We previously informed the Commission that implementation of our AMI project would provide opportunities for improvements to the data available for hosting capacity analysis. *In the Matter of the Xcel Energy 2020 Hosting Capacity Report Under Minn. Stat. § 216B.2425, Subd. 8*, E002/M-20-812, Hosting Capacity Analysis Report (Nov. 2, 2020), Attachment F at 11. This DI use case provides just such an opportunity.

of our analyses of DER hosting capacity and allow for some automation of that process. This should facilitate the development of DER resources.

Transformer Load Management (TLM). This potential use of DI would involve the use of applications running on local meters to monitor, in real-time, the load on a local transformer. Initially, such monitoring would result in alerts to the Company when transformers are at risk for overloading. However, the Company has also contemplated a scenario in which meter-based monitoring is combined with localized load control. Under this scenario, the load on the transformer could be reduced by, for example, temporarily halting the charging of local EVs. The Company believes this application will be crucial as EV and beneficial electrification loads increase. TLM would be a non-wires alternative allowing for more use of existing system capacity. It is expected to significantly reduce the number of distribution transformers that need to be replaced.

Primary Location, Open Primary Conductor, and Vegetation Detection. These applications will help pinpoint outages, reducing outage durations and identifying the cause of transient faults.

Capacitor & Regulator Operation and Health. These applications will detect mis-operations and optimize maintenance.

Power Quality. These applications will enable high-end power quality monitoring (harmonic distortions, transients, flicker analysis, etc.), improving the efficiency of investigations into power quality problems.

Smart Emergency Load Reduction. These applications would facilitate a prioritized and effective emergency load reduction.

D. Project Budget for DI

1. Capital Costs

The capital costs of deploying DI solutions consist of foundational architecture development, infrastructure development, and use case development. These use case development budgets are each based on expected development of the three customer-facing use cases, as well as the three grid-facing use cases of similar complexity, discussed above, for deployment in 2022. Table 1 below provides the capital costs broken down by category. As the Company currently has specific plans through deployment of the initial use cases, the capital budget only consists of expenditures in 2021 and 2022. These budgeted expenditures will provide the foundational capabilities and initial use cases to begin using DI. As we move forward and make decisions regarding future use cases, we will budget for and make additional investments as part of our normal course of business.

Table 1: Capital Costs Budget

Cost Category	Detail Cost Category	2021 Budget	2022 Budget
Software Architecture	Internal Development Costs	$ 332,500.00	$ 308,693
	3rd Party Onshore	798,000	$2,778,237
	3rd Party Offshore	199,500	$138,912
Infrastructure / Hardware	Customer-Facing Infrastructure Cost	332,500	991,777
	Grid-Facing Infrastructure Cost	798,000	457,743
	Itron App Package Infrastructure Cost	199,500	585,242
Use Case Development - Grid Facing	3rd Party Onshore Development	-	2,159,391
	3rd party Offshore Development	-	539,848
	Xcel Energy Development	-	899,746
	Itron App Package Development Cost	-	1,463,106
Use Case Development - Customer Facing	3rd Party Onshore Development	-	2,159,391
	3rd Party Offshore Development	-	539,848
	Xcel Energy Development	-	899,746
	Itron App Package Development Cost	-	1,463,106
Total		**$ 2,660,000**	**$ 15,384,787**

The software architecture development work includes the creation of the software to effectively, reliably, and securely run the distributed intelligence platform in Xcel Energy's back office systems. This includes integration with existing meter data and customer information systems, as well as development of the core load analytics capability which unlocks much of the potential for future applications. These costs were derived through coordinated efforts between the Company and third-party consultants who have experience with technology integration.

Infrastructure / Hardware consists of the additional hardware costs for DI as well as development of data center infrastructure (including servers, storage, computers, and network) to support DI implementation. The advanced meters themselves contain DI capabilities, but additional hardware is necessary to store data and host those processes that interact with the meters. These costs were budgeted based on estimated storage and processing capability required to fully enable DI solutions as well as known or benchmark costs for data center equipment.

Use case development includes incremental software development costs for use cases, system integration, and one-time licensing costs. These costs, in essence, represent the incremental costs above the underlying system architecture for each solution or service the Company is developing. The Company forecasted these costs based upon previous experience of the labor required to develop software as well as known or benchmark values for one-time licensing costs. These costs will vary based upon the complexity and degree of integration required per use case.

Consistent with its request for certification, the Company anticipates seeking recovery of these costs and the O&M costs through the TCR Rider. After development of foundational DI capabilities and deployment of the initial use cases, going forward there will be additional investments to develop future use cases. We anticipate seeking recovery for future DI costs using whatever mechanism is deemed appropriate given the timing and nature of the projects in question. This may involve the Company seeking recovery in future rate case proceedings, through the TCR Rider, or through some other mechanism.

2. O&M

The O&M budget largely consists of the estimated annual costs associated with operating and maintaining the investments in foundational DI capabilities and the initial customer-facing and grid-facing use cases. The Company expects DI O&M costs in the following categories: (1) Governance and Change Management, (2) Product Development (3) Sales and Marketing, (4) Customer Service, (5) Third Party Consulting, (6) Architecture Run Costs, and (7) Use Case Run Costs. Table 2 below provides the current estimate of O&M for 2021 to 2026.

Table 2: O&M Budget

Cost Category	Detail Cost Category	2021 Budget	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget
Customer Support and Governance	Governance and Change Management	-	$9,115	$14,921	$14,921	$14,921	$14,921
	Product Development	$152,000	$109,379	$179,058	$179,058	$179,058	$179,058
	Sales & Marketing	-	$27,345	$44,764	$44,764	$44,764	$44,764
	Customer Service	-	$45,575	$74,607	$74,607	$74,607	$74,607
	Third Party Consulting	-	$729,194	$1,193,718	$1,193,718	$1,193,718	$1,193,718
System upgrades and maintenance	Architecture Run Cost	-	$674,505	$1,104,189	$1,104,189	$1,104,189	$1,104,189
	Use Case Run Cost	-	$2,807,399	$4,595,816	$4,595,816	$4,595,816	$4,595,816
Total		**$152,000**	**$4,402,512**	**$7,207,074**	**$7,207,074**	**$7,207,074**	**$7,207,074**

Governance and change management costs represent the labor involved in overseeing the selection, prioritization, and implementation of DI enabled solutions across and within the Company. Due to the degree of impact that DI may have on existing operations, these resources and activities are critical to ensuring the full value of DI is realized. The costs are based on a bottom up analysis of the existing and some incremental labor resources that would be required, as well as an assumed percentage of time dedicated to DI which is based on the number and complexity of use cases deployed. There is also an assumed split of internal Company resources and third-party resources to fulfill these functions.

Product development costs represent labor involved in the development of new use cases, including data science, product management, and technical field resources. Customer Solutions developed this portion of the budget based on previous experience in developing and managing programs in areas such as Demand-Side Management and reflect the complexity and degree of relation to existing solutions or services that may already exist. There is also an assumed split of internal Company resources and third-party resources to fulfill these functions.

Sales and marketing costs represent the labor involved in raising customer awareness of DI enabled solutions, which are more technical in nature than many existing programs. The Company developed this portion of the budget based on previous experience in marketing of services in more technical areas such as Demand Response and Electric Vehicles and it reflects the complexity and degree of relation to existing solutions or services that may already exist. There is also an assumed split of internal Company resources and third-party resources to fulfill these functions.

Customer service costs represent the labor involved in supporting customers requiring assistance as they engage in these new services, which are more technical in nature than many existing programs. This portion of the budget was developed based on previous experience in customer service delivery in more technical areas such as Demand Response and Electric Vehicles and it reflects the complexity and degree of relation to existing solutions or services that may already exist. The customer service O&M costs are prorated for 2022 to reflect that the Company expects to offer DI applications and associated solutions to customers part way through 2022. The full annualized customer service costs for the initial DI enabled solutions would be incurred in 2023.

Third-party consulting costs consist of labor associated with bringing in outside expertise to further develop and refine the business case, technology architecture, internal governance, and product and change management associated with DI. These costs are based on previous experience with large technology and business change projects, and are reflective of costs obtained through competitive RFP processes.

The ongoing software architecture run cost represents the costs of maintaining and operating the architecture. This value was estimated as 20 percent of the total investment cost for the architecture, based on previous experience with software technology deployment and work with third-party consultants who have experience rolling out technology integration. The 20 percent was assumed to cover software licenses and other fees that would typically be considered O&M.

The ongoing use case run cost represents the costs of maintaining and operating the individual use cases. This value was estimated as 20 percent of the total investment cost for each DI enabled solution, based on previous experience with software technology deployment and work with third-party consultants who have experience rolling out technology integration. The 20 percent was assumed to cover software licenses and other fees that would typically be considered O&M.

3. Estimated Customer Bill Impacts

Keeping customer bills low is an Xcel Energy strategic priority and is a central consideration of our grid modernization efforts. As we have discussed, the investment in DI foundational capabilities and initial DI use cases will provide significant value to our customers. It will however also have an impact on customer bills, resulting from the increased revenue requirement due to our investments and O&M spending necessary to implement the this initiative.

As we did when we proposed certification of AMI and FAN in our 2019 IDP, we have performed a high-level revenue requirement analysis for 2022 through 2026 to illustrate the incremental revenue requirement and estimated bill impact of the DI foundational capabilities and initial use cases. While we did not perform an exhaustive class cost of service model for this subset of investments and O&M expenses, this analysis provides an estimate of the monthly bill impact for a typical residential customer.

We estimated the bill impact by utilizing a series of allocation assumptions applied to the DI costs, using allocators consistent with our 2022 proposed Class Cost of Service Study in the MYRP rate case we submitted on October 25, 2021. Appropriate allocators were applied to distribution capital, distribution O&M, and the remaining costs to develop an estimated residential class revenue requirement. We then divided the estimated residential class revenue requirement by the sales forecast for each year. This results in an estimated overall cost per kilowatt hour (kWh). We then calculated an estimated bill impact based the average monthly residential customer usage of 600 kWh. This assessment shows an estimated 2026 bill impact for our DI investment of approximately $0.31 per month for an average residential customer.

VI. DATA SECURITY AND DATA ACCESS

The Company takes our responsibility to secure and protect data regarding our customers' energy usage very seriously. As we develop the foundational capabilities for DI, one of our focuses is putting into place the appropriate cybersecurity infrastructure and procedures. Our foundational grid modernization and thus, DI infrastructure and architecture, are designed and are being implemented with a robust and multi-faceted approach to cybersecurity. Because each individual meter will be connected to Xcel Energy's backend IT systems, the Company is acting to protect both the privacy of customer energy usage data (CEUD) and the secure and stable operation of our own IT infrastructure.

DI will facilitate improved customer access to CEUD, and the Company will continue to comply with applicable requirements, including those set forth by the Commission in its January 19, 2017 Order in Docket No. E,G999/CI-12-1344 and its November 20, 2020 Order Adopting Open Data Access Standards and Establishing Further Proceedings in Docket Nos. E,G999/CI-12-1344 and E,G999/M-19-505.

The customer-facing applications discussed in Section V.B. above will allow our customers access to their own granular CEUD using their own mobile phones, provided they complete the necessary verification processes. With regard to building level and public purpose data aggregation, monthly kWh consumption data is sufficient for benchmarking purposes and there are no known aggregation standards for more granular data, including the data that can result from DI-enabled analysis. Accordingly, the Company does not plan aggregating more granular data, including that derived from DI analysis, to provide to building owners and public entities.[16]

As the initial DI use cases are deployed, the Company will continue to comply with applicable requirements, and will keep the Commission apprised of its data access and privacy practices through compliance filings, currently required in Docket Nos. E,G999/CI-12-1344 and E,G999/M-19-505.

VII. DI MEETS THE CRITERIA FOR CERTIFICATION

As discussed above in Section III, in 2018 the Commission provided seven factors to address with respect to certification, which included the Commission's Guiding Principles for Grid Modernization. In this section, we address those factors, including the incorporated Guiding Principles for Grid Modernization, to demonstrate why development of the foundational capabilities of DI and deployment of the initial grid-facing and customer-facing use cases should be certified. In short, the DI initiative is the implementation of cutting-edge technology that will improve the insights the Company has into the operation of the distribution grid, which should help us detect and remedy problems, and improve customers' insights into and, ultimately, control over energy usage. The capabilities provided by the development of foundational DI capabilities and the development of the initial use cases will also enable future use cases that can, among other things, facilitate the integration of DER and further encourage customer behavior that results in the shedding or shifting of load. DI will, thus, improve the safe and reliable operation of the distribution grid while also facilitating more efficient energy usage. Importantly, DI is one of the technologies the Company is relying on to move to its ultimate goal of 100 percent carbon-free electricity by 2050.

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[16] *See* the Company's December 1, 2020 Compliance Filing, *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities* and *In the Matter of a Petition By Citizens Utility Board of Minnesota to Adopt Open Data Standards*, Dockets E,G999/CI-12-1344 and E,G999/M-19-505, Compliance Filing, Attachment B at 4-5.

In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program and *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report*, Dockets E-002/M-17-775 and E-002/M-17-776, Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request (Aug. 7, 2018) at 9.

A. Why the Project is Necessary for Grid Modernization

Section 216B.2425, subd 3 of the Minnesota Statutes, which provides for certification, addresses the modernization of the distribution grid in terms of the following objectives:

> enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.

DI is itself an innovative technology that advances many of the goals of grid modernization. As discussed above in Sections V.B and V.C, the initial customer-facing and grid-facing use cases will facilitate communication with customers and enhance the reliability of the distribution grid. The initial use cases and the foundational DI investments will also provide the foundation for future uses of DI to further promote the modernization of the distribution grid.

B. DI is in the Public Interest

The initial use cases provide a variety of benefits to the public, which are discussed above in Sections V.B and V.C. More generally, the foundational DI investments and initial DI use cases are in the public interest because they are the next step in developing the advanced capabilities the Commission itself envisions for advanced metering:

> to see load in real time, understand their impact, and shape or shift load through advanced rates and other demand response methods can help reduce system costs and give customers more control over their energy consumption.[17]

C. DI Satisfies the Grid Modernization Principles

DI satisfies the Grid Modernization principles from Docket 15-556 for the reasons outlined below.

1. *DI will maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies*

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[17] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket E-002/M-19-666, Integrated Distribution Plan (Nov. 1, 2019) at 8.

DI is consistent with this Grid Modernization principle. The enhanced insights into the secondary system provided by the grid-facing applications will promote safety, security, reliability, and resiliency. The initial use cases will aid in identifying problems before they arise and contemplated future use cases will also build upon these capabilities. The Company will have better insight into the condition and operation of the distribution grid, which will allow it to detect and resolve issues before they impact customers.

2. *DI will enable greater customer engagement, empowerment, and options for energy services*

The DI capabilities of the new meters will enable the Company to provide customers with more detailed information regarding their energy usage, which will empower them to make decisions for financial and/or environmental reasons. The Company also anticipates that options for energy services will, in the future, be enabled by DI.

3. *DI will help the Company move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies*

DI is itself a new technology that promotes efficiency, and its inherent flexibility may provide a platform that enables other new technologies. As new distributed technologies are developed and deployed, the Company may determine, depending on the technology, that software applications running on individual meters can help monitor, control, or interact with those new technologies. When it is appropriate to do so, the Company would then be able to remotely install such software on the meters. By putting the foundational capabilities for DI into place now, Xcel Energy is positioning itself to be able to act nimbly in response to future innovations.

4. *DI can promote optimized utilization of electricity grid assets and resources to minimize total system costs*

The capabilities of the grid-facing DI applications will help us optimize our grid assets and resources. The initial grid-facing applications, which are discussed above in Section V.C, will help us to more quickly and efficiently identify and address problems with the distribution system. We anticipate that future uses of DI, which the development of foundational capabilities and deployment of initial use cases will facilitate, will promote an optimized utilization of assets. In particular, the contemplated future Transformer Load Management (TLM) use case could significantly reduce the number of distribution transformers replaced.

5. Facilitate comprehensive, coordinated, transparent, integrated distribution system planning

The Company will be better positioned to conduct comprehensive, coordinated, transparent, and integrated distribution system planning as result of DI. The Connectivity grid-facing use case, discussed above in Section V.C.3, will facilitate more accurate system modelling by reducing GIS mapping errors, and the granular data regarding the performance of the secondary system will provide additional inputs into the planning process. Through improved insights into energy end-uses, such as through EV detection, our planning and forecasting will be significantly enhanced. We will be able to better leverage scenario-based planning to ensure timely, correctly sized system investments to meet our customers' needs.

D. The Intended Objectives for DI

One of our intended objectives with DI is to empower customers by providing them with greater information regarding and control over their energy usage. We expect that this will result in improved customer satisfaction, customer savings, greater energy efficiency, and, as a result, reductions in carbon emissions. For that reason, DI is one of the portfolio of technologies the Company believes is important to help achieve its carbon reduction goals.

The Company also intends to improve the reliability and efficient operation of its secondary system through grid-facing use cases involving DI, which are discussed above in Section V.C. Using on-meter analysis of data collected by the meters, in combination with back-end computational processing, the Company will be able to detect and resolve emergent problems before customers even become aware of them.

E. The Company is not Aware of Any Alternatives that Would Satisfactorily Meet the Intended Objectives

The Company could choose not to make use of the DI capabilities of the new Riva 4.2 meters. Under this scenario, the meters would simply be used as AMI meters, which are still a significant step forward in technology from the Automated Meter Reading (AMR) meters that are currently installed at most customer locations. However, this alternative, while feasible and lower-cost in the near future, would not realize the greater objectives the Company envisioned for its AMI initiative.

Another alternative is that the Company could, perhaps, install other smart devices throughout the distribution grid to attempt to achieve some of the same benefits as those available from enabling the DI capabilities of the Riva 4.2 meters. This alternative, however, would require the purchase and installation of an entire set of incremental equipment in addition to the meters. In addition to the additional hardware costs, such a project would also involve software and other IT costs. Finally, we are not aware of any incremental benefits an approach such as this would have as compared to developing the foundational capabilities to enable the DI capabilities of the meters and then deploying initial DI use cases.

F. Cost-Benefit Analysis of the DI Project

We have conducted a cost-benefit analysis (CBA) for the development of the foundational DI capabilities and deployment of initial customer and grid-facing applications. A CBA is a methodology that compares the quantifiable benefits and costs of a project or initiative to evaluate the relative value of a project. The CBA provided, as required by the Commission, is a comparison of the net present value (NPV) of the costs of the DI development of the foundational DI capabilities and deployment of the initial use cases with the NPV of the quantified benefits on a revenue requirement basis. The structure and approach of the model utilized is consistent with the Company's approach to similar cost-benefit analyses in the past, such as those provided to the Commission through our certification request for AMI and FAN in our 2019 IDP in Docket No. E002/M-19-666.

The CBA provides one point of reference when considering the investments in DI. There are limitations associated with a CBA, both with respect to unquantifiable qualitative benefits as well as those quantifiable benefits that cannot precisely be estimated. The resulting benefit-cost ratio should be considered as just one data point in a more wholistic assessment of a project. A more robust assessment would likely include additional factors that could include other potential benefits of future DI uses, the contribution of DI to the Company's carbon emission reduction efforts, the ways in which DI contributes to the Company's and the Commission's goals for grid modernization, benefits to customers that are not quantified, and the needs and goals of other key stakeholders, including the Minnesota Legislature.

In conducting the CBA, we only included customer bill savings for 2022 through 2026 as identified benefits. While we expect DI to provide significant benefits other than bill savings, particularly when the next wave of use cases is deployed, reduced customer bills were the only benefits that the Company could quantify at this time with sufficient certainty to include in the analysis.

The CBA model utilizes the Discounted Cash Flow (DCF) formula and the 2021 NPV for costs and benefits, to determine the value of the DI investment. The model takes the annual capital costs and capital benefits, which are the estimated direct customer benefits, and makes assumptions regarding how those costs and benefits may be reflected in rate base. The model also estimates a net capital revenue requirement as a function of depreciable book and tax lives for the assets. All streams of costs and benefits are discounted across five years using the WACC.

The key costs of the DI initiative include software, architecture, hardware, and system development. In addition to this, there was a contingency estimate added to the forecasted costs of the components and input into the model as a cost. In essence, the model evaluates the full cost of the project to develop foundational DI capabilities and deploy the initial use cases and assumes that we would need to spend the entire contingency amount.

The CBA indicates that the ratio of quantifiable benefits to costs is 0.93. Although this is slightly lower than 1.0 (the level at which quantifiable benefits and costs are equal), it does not take into consideration other non-quantified benefits that are discussed below. Crucially, the development of foundational DI capabilities and deployment of initial DI use cases will position the Company to subsequently deploy future DI use cases which will further benefit the Company, customers, and the environment. Although the Company cannot quantify such benefits at this time, they are expected to be considerable, and it is not unusual for an investment in foundational technology to have a benefit to cost ratio below 1.0.

The CBA is summarized in Table 3 below.

Table 3: DI Foundational Capabilities and Initial Use Cases Cost-Benefit Ratio Net Present Value 2021 (millions)

	Total
Benefits	**40**
O&M Benefits	0
Other Benefits	40
CAP Benefits	0
Costs	(43)
O&M Expense	(26)
Change in Revenue Requirements	(17)
Benefit/Cost Ratio	**0.93**

The approximately $17 million of NPV of the Change in Revenue Requirements results from approximately $2.6 million in capital investments in 2021 and approximately $15.4 million in capital investments in 2022, as noted in Section V.D. All of the 2021 investments are in Software Architecture and Infrastructure /

Hardware, which are investments in the foundational capabilities. However, in 2022, $10.1 million of the $15.4 million represents investments in use case development, approximately half of which are for grid-facing use cases and half of which are for customer-facing use cases.

The CBA is tied to the Company's meter installation schedule. We are estimating benefits will begin to accrue in 2022 as the first DI-capable meters are deployed and customers with the new meters can begin to benefit from the initial customer-facing use cases. Between 2022 and 2026, we estimate that benefits will increase as an increasing proportion of our customer base is able to use the DI capabilities of the new AMI meters. We took a conservative approach and chose not to include benefits beyond 2026, taking as the initial reference the meters to be installed in 2022 and assuming a 5-year life for software. As a practical matter, we expect the customer-facing use cases will continue to create savings for our customers in 2027 and beyond; however, we are not quantifying those likely future benefits for this CBA and they should be considered qualitative benefits.

1. *Quantified benefits*

Customer savings through 2026. As noted above, the quantified benefits included in the CBA are customer bill savings for 2022 through 2026. These are the projected benefits from customer engagement with the initial customer-facing use cases. As we provide our customers with granular and useful information regarding the energy usage, particularly the energy analysis use case, they will be empowered to make decisions which result in lower monthly bills.

Based on Company and third party consultant research into current market characteristics as well as comparative programs across the United States, we assume that 9.75% of customers with AMI meters will enroll in the real-time energy insights service as it becomes available in 2022. Through a variety of engagement methods, including, but not limited to, appliance disaggregation information display (i.e. cost or carbon intensity of specific appliances), energy "hog" notifications (presence of particularly energy intensive device), personalized energy saving tips, and behavioral comparisons, it is projected that those customers will save 5% of their annual energy consumption. As TOU rates are introduced to the broad population of customers beginning in 2024, it is further projected that behavioral changes promoted by this service will result in 3% shift of energy consumption from peak periods to non-peak periods, resulting in further bill savings for those customers.

2. *Non-quantified benefits*

Customer savings after 2026. As noted above, the CBA only incorporates customer savings from 2022 through 2026. However, we expect that the investments in the foundational DI capabilities and initial customer-facing use cases will continue to result in lower monthly bills for engaged customers after 2026.

Environmental benefits. While DI is one of the technologies that will help the Company achieve its carbon reduction goals, we are not able to provide a quantitative estimate of reduced emissions. Consequently, the Company is not providing an estimate of the value of emission reductions in dollar terms using the Commission's environmental cost values. Instead, such benefits must be considered qualitatively. The environmental benefits will largely result from the impact the initial customer-facing use cases have on customer behavior.

Avoided System Costs. The energy insights use case, as described above, is projected to yield significant energy savings and, in time, peak demand reductions, which can be translated into system benefits through the Conservation Improvement Program. These benefits will be proposed through the appropriate CIP mechanism as the services become ready to launch.

Distribution grid reliability and efficiency. The secondary equipment assurance use case will improve our operation of the distribution grid. At the present time, we are not able to present estimates of those benefits; however, we expect they will be reflected in future metrics of the reliable and cost-effective operation of the secondary system.

Public safety. The secondary equipment assurance and meter bypass theft detection use cases will help us locate and remove potentially dangerous conditions, particularly fire hazards.

Planning and modeling. The connectivity grid-facing use case for DI will facilitate better GIS mapping of the physical location of our secondary system. In addition, the EV detection customer-facing use case will improve our information regarding the locations where EV charging takes place. Our system modelling and planning will improve with better data, which should also benefit the DER interconnection process.

Increase Meter Service Life. The Riva 4.2 can be remotely upgraded and the development of the foundational DI capabilities will provide the infrastructure and IT architecture to allow for such upgrades, which will increase the service life of the meters.

Future Use Cases. The experience, infrastructure, architecture, and capabilities resulting from our development of foundational DI capabilities and deployment of the initial use cases will provide an important foundation for future use cases, which are expected to further modernize the grid in ways that benefit our customers and the environment, including an improved DER interconnection process and customer-facing uses of DI that encourage and incentivize behavior that sheds or shifts loads during periods of peak demand.

G. DI Will Facilitate Other Initiatives and Projects

DI is a crucial part of the Company's overall grid modernization plans and is one of the portfolio of technologies that will help the Company achieve its carbon emission reduction goals. DI also has an important role to play in supporting CIP, TOU rates and the expansion of DER.

The Company expects that DI capabilities will be used to facilitate powering quality analysis and hosting capacity analysis in connection with DER. The granular data and customer engagement facilitated by DI should also enable expanded and more detailed TOU rates, which will promote more energy efficient customer behavior resulting in customer savings and reductions in carbon emissions. The experience, infrastructure, architecture, and analytical capabilities resulting from development of the foundational DI capabilities and deployment of the initial use cases will position the Company for these later use cases. In addition, as discussed above in Section V.B, the Company plans to use DI to promote and improve its EV programs to the ultimate benefit of those owning such vehicles. As with TOU rates and DER, this use of DI can promote behaviors that result in reduced carbon emissions.

VIII. CONCLUSION

Xcel Energy is at the forefront of the electric utility industry. DI will provide the Company with tools to better understand and manage its distribution system, and will provide customers with tools to better understand and control their own energy usage. This exciting new technology will benefit the public, Xcel Energy's customers, and the Company's operations. We request that the Commission certify the Company's development of foundational capabilities for DI and its deployment of the initial DI use cases.

APPENDIX H: RESILIENT MINNEAPOLIS PROJECT CERTIFICATION REQUEST

I. EXECUTIVE SUMMARY

A. Introduction

The past two years have brought unprecedented economic and social hardship to the residents of Minneapolis, including economic and health impacts from the COVID-19 pandemic and the civil unrest following the murder of George Floyd. These events have disproportionately impacted Black, Indigenous, and People of Color (BIPOC) communities, and have led to increased efforts to address the racial inequities that persist in Minnesota. They have also focused attention on the fact that BIPOC communities tend to be disproportionately vulnerable to a variety of disruptions, including but not limited to the impacts of climate change, and are seeking ways to improve community resilience to such disruptions.

At the same time, the Company and other stakeholders are seeking ways to integrate into the electric system new distribution-level technologies like distributed solar, battery systems, and microgrids that can deliver a wide array of benefits to the electric system. These benefits, if systems are carefully planned and optimized, include backup power for resilience during outages, mitigation of peaks at the system and feeder level, local distribution system support, deferral of conventional distribution system investments, and emission avoidance, among others.

The Resilient Minneapolis Project (RMP) is a proposed initiative, implemented at three Minneapolis locations with BIPOC-led partner organizations, that seeks to improve communities' resilience to crises while advancing the Commission's objectives for Integrated Distribution Plans (IDPs):

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new projects, new services, and opportunities for adoption of new distributed technologies; and

- Provide the Commission with the information necessary to understand Xcel Energy's short- and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of customer cost and value.

The RMP will be implemented at three locations: (1) the North Minneapolis Community Resiliency Hub; (2) Sabathani Community Center; and (3) the Minneapolis American Indian Center. At each site, the Company will work with partners to install rooftop solar, battery energy storage systems (BESS), microgrid controls, and necessary distribution system modifications to integrate these technologies. These systems will not only be managed with reserve capacity to provide power for critical services during electric system outages, but also – recognizing that outages are today generally infrequent and brief – dispatched and optimized daily to mitigate system peaks, manage and shape demand, and integrate more solar generation.

The Company seeks certification of the RMP under Minn. Stat. §216B.2425 as a grid modernization initiative meeting the statutory criteria for utilities operating under multiyear rate plans.

The remainder of this Appendix is organized as follows:

- Section I provides a summary clarifying the purpose and history of the RMP;
- Section II describes how the Company selected the three RMP sites;
- Section III describes the three sites, including lead partner and supporting organizations, location on the grid, beneficiaries, technologies proposed, current loads, and complementary objectives addressed by the RMP;
- Section IV details estimated costs, anticipated benefits and presents a benefit-to-cost ratio;
- Section V provides an implementation schedule;
- Section VI proposes a process and schedule for reporting lessons learned; and
- Section VII is the Company's request for certification.

B. Community Resiliency

The term "resiliency" is used in different ways in different contexts. Sometimes, it is used to refer to the ability of the electric grid or other infrastructure to recover quickly from an outage or other disruption, and/or "hardening" of electricity assets to withstand increasing extreme weather. At other times, the term is used to refer to communities' own ability to withstand and recover from a variety of disruptions, including but not limited to those related to climate change, by ensuring continued access to electricity and other critical services. This proposal addresses primarily the latter sense of resiliency.

The Urban Sustainability Directors Network (USDN) 2018 paper, *Resilience Hubs: Shifting Power to Communities and Increasing Community Capacity*, provides useful context for the Company's approach in the RMP. That paper defines resilience as:

> "the ability to anticipate, accommodate and positively adapt to or thrive amidst changing climate conditions, while enhancing quality of life, reliable systems, economic vitality, and conservation of resources. Resilience requires community capacity to plan for, respond to, and recover from stressors and shocks. Shocks are major disruptions such as storms, heat waves, derechos, or other extreme weather events – often intensified by climate change – that can disrupt a variety of critical systems. Stressors refer to the everyday issues that make people and communities more vulnerable to those shocks, including epidemic drug use, poverty, aging infrastructure and unemployment – all of which are exacerbated by shocks and make it more difficult to respond and recover… A more resilient community also includes consideration of foundational elements of community quality of life, such as greater access to jobs, more affordable housing, strengthening infrastructure, and stronger social support systems. [1]

In the USDN framework, a Resilience Hub is a facility designed to support residents and coordinate resource distribution and services before, during, or after a natural hazard event. It can also be used year-round as a neighborhood center for community-building and revitalization, to reduce GHG emissions, and improve local quality of life. Resilience Hubs are best designed, according to USDN, by engaging community members, including the most vulnerable, throughout planning and implementation, or what USDN calls "a bottom-up approach centered on community co-development and leadership." Key elements of a successful Resilience Hub include strong community support, an appropriate building where residents can gather to receive critical services, resources for emergencies (food supply, refrigeration, medical services, etc.), and on-site energy resources for a potential extended outage (solar, batteries, standby generators).[2]

This is the type of resilience the Company seeks to support in the RMP, and the collaborative approach we are taking to design the initiative with long-standing and trusted BIPOC organizations in each of the three RMP communities. BIPOC

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[1] *See* https://ppp-ejcc.com/wp-content/uploads/2020/03/USDN-Resilience-Hubs-2018.pdf, page 6.
[2] Ibid, pages 2-5.

communities in Minneapolis tend to be disproportionately impacted by extreme weather and other disruptions (shocks), and disproportionately vulnerable because of pre-existing health conditions, low wealth, historic and continuing discrimination, housing, high energy costs, urban heat island effects, and many other factors (stressors).[3] Working with these partners to improve resiliency means recognizing their existing vulnerabilities, investing in critical infrastructure to help in times of crisis and hasten recovery after a disaster, and ensuring a secure power supply for Resilience Hubs in the event of emergencies or extended outages. It also means – as the USDN paper emphasizes – working closely with our community partners to "co-create" solutions to the resiliency and other challenges they face, and looking for ways to address needs that go beyond what we can include in this IDP.

We will support resilience by providing battery energy storage systems (BESS)-enabled microgrids at each site, paired with solar generation. Resilience Hubs will consist of a customer building or multiple buildings in close proximity, where the Company will own and operate a BESS and associated equipment including islanding switch, microgrid controller and interconnection hardware, interconnected directly to the distribution system in front of the customer's meter. The BESS will be paired with rooftop solar generation and/or standby generators owned by the partner organization. Should there be a grid outage, the system would automatically switch to "islanded" mode, providing back-up power even for an extended outage by managing the available energy stored within the battery, solar and back-up generation assets on site, and reducing loads as needed to ensure the site's critical functions can continue given the available energy.

The Clean Energy Group's Resilient Power Project interactive map[4] shows only two microgrid projects in Minnesota today – OATI's microgrid in Bloomington, and a nature center in Duluth – so the RMP would not only more than double the number of resiliency projects in Minnesota, but would also install the first resiliency projects specifically focused on delivering benefits to under-resourced and BIPOC communities.

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[3] *See*, for example, the Minnesota Pollution Control Agency's mapping of areas of environmental justice concern (https://www.pca.state.mn.us/about-mpca/mpca-and-environmental-justice) and Minnesota Department of Health findings on health equity (https://data.web.health.state.mn.us/web/mndata/healthimpacts).

[4] See https://www.cleanegroup.org/ceg-projects/resilient-power-project/map/.

C. Grid Services

The primary benefit for the RMP site hosts is enhancing resiliency, generally needed infrequently and for brief durations. During normal grid operations, the solar and BESS assets will be managed to deliver a range of grid services. They will be dispatched and optimized to mitigate peaks at the system and feeder level, integrate more solar generation, and reduce emissions. Section IV details the full range of grid services the Company aims to evaluate in the RMP. In Section VI, we discuss how we propose to report lessons learned from managing the assets to deliver these grid services.

Importantly, while these technologies can deliver multiple different grid services, not all can be delivered at once. There is limited experience in how to optimize such systems to deliver the greatest benefits for all the Company's customers while reserving adequate capacity to provide resiliency for the host. Thus, the RMP is also designed to deliver learnings for the Company, which will ultimately benefit all our customers, on optimizing the day-to-day grid services from solar and battery assets.

D. Equity Objectives

Designing the RMP projects in collaboration with BIPOC-led organizations has brought into focus that these communities have broader energy equity objectives that are not limited to serving as Resilience Hubs. These include:

- Energy affordability and reducing energy burden for community residents and businesses;
- Equitable access to renewable energy, and the opportunity to use renewable energy and energy efficiency projects to create jobs and build community wealth in chronically under-resourced and under-invested communities;
- Workforce training, diversification, and BIPOC energy careers; and
- Environmental justice concerns and the desire to reduce or eliminate emissions in neighborhoods that have historically suffered disproportionate pollution impacts.

All our RMP partners are active in workforce readiness and career pathways, in some cases specific to clean energy workforce development. We are designing the RMP projects to link directly to workforce development in solar, energy storage and related areas.

We emphasize that while the primary justification we present for the RMP is couched in terms of the Commission's IDP objectives, and the resiliency and grid services these technologies can deliver, the energy equity objectives in the list above are crucial to our partners and thus to success of the RMP. Most of these equity objectives, with the exception of carbon avoidance, are not directly quantified in monetary terms in the cost/benefit analysis in section IV. They are nonetheless central to our partners and should be considered as important non-quantified benefits.

E. History of the RMP

The RMP concept originated in discussions, going back to our 2019 IDP, with the City of Minneapolis around a Non-Wires Alternative (NWA) Pilot. The Company continued in 2019-2020 to seek locations on the distribution system where an NWA pilot would meet an evident need. In addition, in the 2020 economic recovery docket, the Commission asked utilities to propose investments that could aid in Minnesota's recovery from the COVID-19 pandemic – specifically, "all ongoing, planned, or possible investments that meet the following conditions: provide significant utility system benefits; are consistent with approved resource plans, approved natural gas distribution infrastructure or pipeline safety plans, triennial conservation plans, and existing Commission orders; reduce carbon or other pollutant emissions in the power sector or across economic sectors; increase access to conservation and clean energy resources for Minnesotans; create jobs or otherwise assist in economic recovery for Minnesotans; and use woman, veteran, or minority owned businesses as much as possible and provide documentation of these efforts."[5]

One of the economic recovery investments the Company proposed was an NWA pilot in Minneapolis focusing on rooftop solar, EV charging, battery storage, demand response, and energy efficiency, with an estimated budget of $4 to $8 million. However, as our discussions with Minneapolis continued over 2019 and 2020, the Company struggled to identify an appropriate NWA location, primarily because there were no obvious distribution system locations within Minneapolis with a near-term need for the sort of conventional distribution system improvements that an NWA solution could avoid. It became clear that we needed to broaden our focus for this pilot to include not just NWA, but also community resiliency and economic recovery for BIPOC communities disproportionately impacted by the pandemic. We began reaching out to community groups to identify sites where increased resiliency would

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[5] *See* Minnesota Public Utilities Commission NOTICE, *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*. Docket No. E,G999/CI-20-492 (May 20, 2020).

help ensure safety and facilitate improved delivery of essential services or goods during times of need. We also outlined a new timeline, balancing the need to maintain momentum with the time needed for a collaborative and inclusive process in designing the pilot projects.[6]

The RMP, as the Company is currently pursuing it in collaboration with our community partners, remains consistent with the NWA pilot proposed in 2020 in terms of the technologies proposed and many of the grid services those technologies will be managed to deliver. However, the RMP objectives are now considerably broader than just implementing an NWA pilot to avoid conventional distribution system investments. We are now seeking to enhance community resilience as defined in the USDN paper, as well as deliver an array of grid services during routine, non-emergency operations.

Two learnings have emerged already from our RMP planning stages. First, a genuinely collaborative and inclusive process takes more time than we expected. Consulting with community groups, developing the Request for Applications described in the next section, and working with our partners to flesh out the details of these proposed pilots has taken many months, and will continue to evolve over 2022 and 2023 if the Commission approves the RMP initiative. This is simply the time required for a "co-creation" process which is critical to building trust with community members and ensuring that the projects reflect their interests and priorities. Without that co-creation process, these pilots would likely not be successful because they might not address the communities' core needs.

Second, while our partner organizations are certainly interested in technologies such as solar, batteries and microgrids, their primary objectives are to achieve broader advancements in equity, energy affordability, environmental justice, and opportunities for energy careers. As such, some of our partners have asked the Company to support measures not directly linked to the distribution system but critical to them: replacing outdated HVAC systems, making buildings more efficient, replacing lighting, etc. While those costs are not included in this request for certification, they are crucial to our partners, so the Company is working to support those efforts through our existing programs and external cost-sharing. Increased targets for low-income spending, as well as support for efficient fuel-switching, under the recently passed Energy Conservation and Optimization Act of 2021 may create future opportunities to

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[6] *See* Xcel Energy COMMENTS, *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*. Docket No. E,G999/CI-20-492 (October 16, 2020).

support our partner organizations in their energy goals that are not directly related to the IDP.

II. PROCESS TO SELECT RMP SITES

At the time the Company proposed a City of Minneapolis NWA pilot in the economic recovery docket, we had not yet identified specific locations or partners. Mindful of the larger context of civil unrest, disproportionate impacts on BIPOC communities, and ongoing racial and economic disparities in Minneapolis, we sought to identify sites where implementing community resiliency pilots could also advance equity objectives as discussed above. We took several steps:

A. Request for Applications

The Company developed a Request for Applications (RFA) inviting organizations to propose a resiliency initiative. The RFA explained the goal to enhance community resiliency and the Company's interest in supporting projects that use solar, energy storage, and microgrids to create a Resilience Hub to deliver critical services in the event of an electrical system outage. We suggested Resilience Hubs could include facilities such as community centers, schools, food shelves, hospitals or clinics, transportation hubs, communications infrastructure, etc., but that we would rely on the community organizations themselves to identify the most appropriate locations. The stated objectives were (1) advancing the clean energy future, (2) creating renewable energy projects in under-represented communities, (3) improving outage restoration times, (4) securing facilities' power supply, and (5) creating more clean energy jobs.[7]

We opened the RFA to all Xcel Energy electric customers located in Minneapolis, but specifically encouraged BIPOC-led organizations to apply, and distributed the RFA to such organizations both directly and through contacts in the Mayor's Office, City Council, and other networks. We informed interested parties that we would give preference to projects that employ and train community members and are implemented by a certified minority or woman-owned business or BIPOC-led non-profit organization – a preference the Company also intends to apply when we issue Requests for Proposal (RFPs) in 2022 to select vendors to design and install the chosen technologies. The RFA was issued in March 2021 and we requested responses in April 2021.

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[7] Xcel Energy. Resilient Minneapolis Project call for applications, March 2021.

B. Evaluation Criteria

To select the strongest partners and sites for RMP implementation, we designed a robust and transparent selection process, applying scoring criteria and working with both internal and external reviewers.

We established four minimum criteria that all projects must meet to be scored:

- *Geographic location*: project site is in Minneapolis, pursuant to our NWA proposal in the economic recovery docket.
- *Safety*: project would not violate any local, State or Company safety requirements.
- *Regulatory compliance*: project can be implemented under existing rules and regulations governing Xcel Energy; the goal of RMP is not to create new regulatory frameworks.
- *Physical site requirements*: proposed facility must be structurally and electrically sound and have adequate space for the assets proposed.

We then established eight scoring criteria, with definitions, scores and weights assigned to each, as shown in Table 1 below.

Table 1: Weighted Scoring Criteria for RMP Project Selection

Criterion	Requirement	Scoring	Weight
Scope of project benefits	Project should demonstrate how its benefits extend to the community at large or particular under-served segments of the community.	Project benefits relatively few people = 0 points Project benefits greater number, or benefits a disadvantaged group = 5 points Project benefits large number of people and/or disadvantaged groups = 10 points	15%
Geographic location preference	Projects located within the Northside or Southside Green Zone, or within a City-designated Cultural District, are preferred.	Not in a designated Green Zone or Cultural District = 0 points In a Green Zone or Cultural District = 10 points	5%
Impact on distribution infrastructure	Projects must create minimal need to modify/upgrade the existing distribution infrastructure	Expensive modifications = 0 points Limited modifications = 5 points No modifications = 10 points	15%
Maturity of proposed technology and innovation in application of technology	Projects should deploy proven technologies. More points given to projects that apply proven technologies in a new and innovative way.	Novel or unproven technologies = 0 points Mature or "off the shelf" technologies, standard application = 5 points Particularly innovative application of technologies = 10 points	15%
Project timing	As shown in the project timeline in the application, projects should be ready for construction by mid-2022.	Not ready to begin construction by mid-2022 = 0 points Ready to begin construction by mid-2022 = 10 points	10%
Experience of project lead	The application requests a designated point person or people for project design and implementatoin, and description of their experience and background relative to project planning, energy and/or sustainability.	No point person designated = 0 points Point person with limited relevant experience = 5 points Point person with extensive relevant experience = 10 points	15%
Strength of project team	The Application requests a description of project partners.	Single implementer; no partners = 0 points Multiple partners = 5 points Multiple partners and strong community-based organization = 10 points	15%
Additional resources leveraged	Projects that leverage additional financial or other resources to complement Xcel Energy funds are likely to have greater chances of success.	No financial or in-kind resources proposed to leverage RMP funds = 0 points Some additional resources leveraged = 5 points Significant additional resources, e.g. matching funds requested = 10 points	10%

C. Responses to RFA

The Company received applications from six organizations, all led by and/or serving primarily BIPOC populations in Minneapolis:

1. Renewable Energy Partners: North Minneapolis Community Resiliency Hub

2. Native Sun Community Power Development: Little Earth of United Tribes
3. Seward Redesign Inc: Downtown Longfellow Community (Coliseum Building)
4. Minneapolis American Indian Center
5. Sabathani Community Center
6. Friends of Global Market: Midtown Exchange Campus

Figure 1 below shows the approximate locations of each proposed project, overlain on the City of Minneapolis Northside and Southside Green Zones.[8] The numbering corresponds to the list above and does not reflect any sort of ranking.

[8] The Green Zones, a product of the **Minneapolis Climate Action Plan** Environmental Justice Working Group, are "place-based policy initiative[s] aimed at improving health and supporting economic development using environmentally conscious efforts in communities that face the cumulative effects of environmental pollution, as well as social, political and economic vulnerability." See https://www2.minneapolismn.gov/government/departments/coordinator/sustainability/policies/green-zones-initiative/#:~:text=%20Green%20Zones%20Initiative%20%201%20Background.%20Low-income,was%20created%20by%20the%20City%20Council...%20More%20.

Figure 1: RMP Applicant Approximate Project Locations Overlaid on Minneapolis Green Zones

All six applicants proposed a combination of solar, energy storage, and microgrid technologies, with some also proposing energy efficiency and building envelope measures, efficient electric heating and cooling, electric vehicle charging, building automation, and other technologies. All six applicants are strongly embedded in their respective communities, and all proposed an integrated vision for how these technologies can be employed to improve resiliency, enable distributed generation and storage, create flexible demand to address distribution system constraints, and promote broader objectives of energy equity, affordability, and workforce development. Many of the organizations also house commercial tenants including BIPOC-led businesses and non-profits focused on social services, employment, racial justice and related areas, and explained how their proposed activities would improve energy affordability and support the work of those organizations.

D. Review Committee

Next, we convened an application review committee consisting of internal and external reviewers, balancing technical expertise in distribution technologies, regulatory expertise, and knowledge of the communities and applicant organizations. The Company particularly appreciates the expertise of our external reviewers, whom we recognize here:

- Paul Williams, President and CEO, Project for Pride in Living
- Jonathan Palmer, Executive Director, Hallie Q. Brown Community Center
- Kelly Muellman, Sustainability Program Coordinator, City of Minneapolis
- Patrick Hanlon, Director of Environmental Services, City of Minneapolis

We incorporated feedback from our external reviewers to finalize the scoring criteria above, then sent the applications to our reviewers. The committee reviewed all applications and supporting materials against the agreed-upon criteria. None of the six applications was eliminated based on the four minimum criteria described in section B, so the committee proceeded to score them all against the scored criteria in Table 1. The committee's consensus scores and rankings are shown in Table 2. They represent the average of all reviewers' assigned scores, to which we applied the weighting in the second column to derive the overall weighted score for each project in the bottom row of the table.

Table 2: Final, Weighted Scores for RMP Project Applications

Criteria	Weight	Coliseum	Global Market	MAIC	Sabathani	REP	Little Earth
Scope of Benefits	15%	5	10	9	10	6	0
Location	5%	0	10	10	10	10	10
Impact on Distribution	15%	5	0	10	10	4	1
Technology	15%	4	6	5	7	10	9
Timing	10%	0	5	9	10	10	1
Experience of Lead	15%	3	6	5	10	10	7
Strength of Team	15%	3	4	5	9	10	8
Resources Leveraged	10%	1	0	10	9	10	7
Weighted Scores		**3.1**	**4.9**	**7.5**	**9.3**	**8.5**	**5.1**

We notified the top three applicants of our desire to work with them to flesh out details of their projects and include it in this IDP request for certification. We thanked the remaining applicants and offered to continue conversations with them to support their efforts through existing programs other than the proposed RMP.

III. THREE SITES FOR RMP IMPLEMENTATION

Through the application process described above, the Company selected three sites to implement the proposed RMP. At each site we are working with one of Minneapolis' foremost BIPOC-led organizations, with deep and long-standing relationships in the African-American and Native communities, to improve resiliency while meeting a variety of complementary objectives.

A. Renewable Energy Partners: North Minneapolis Community Resiliency Hub

1. Project Lead and Partners

Renewable Energy Partners (REP) is a state and local-certified Minority Business Enterprise (MBE) based in North Minneapolis and formed in 2014.[9] Its vision is to

[9] This section is derived from REP's website, Firm Capability Statement attached to this filing, and response to Resilient Minneapolis Project call for applications, April 2021.

"address the numerous disparities in our community, including education, skills gaps, and economic participation, to increase the health, wealth, and homeownership of those around us."[10] REP's goals are to 1) develop solar energy and other energy projects with community benefits, 2) provide electrical and construction labor for Minnesota's solar energy market, and 3) training and jobs for BIPOC workers in utility and energy-related careers. Please see the *Firm Capability Statement,* provided as Attachment M, for additional information.

REP currently operates the Regional Apprenticeship Training Center (RATC) at 1200 Plymouth Avenue North to deliver workforce training in emerging energy-related careers. REP has installed a 166 kW rooftop solar installation and 30 kW battery system at the RATC, and also partnered with others to install two community solar gardens designed to serve low-income households: a 365 kW system on North High School, and the 176 kW Emerge Second Chance Community Solar Garden on a nonprofit mattress recycling facility that provides job training for formerly incarcerated citizens.[11]

REP's partners for the North Minneapolis Community Resiliency Hub are Minneapolis Public School (MPS) and the University of Minnesota. MPS will host the solar and battery assets on three of its buildings. The University of Minnesota has an existing partnership with REP to develop clean energy workforce curriculum and training and will continue those efforts through the installation of solar, battery storage, and microgrid technologies.

2. *Location and Beneficiaries*

The North Minneapolis Community Resiliency Hub will be implemented on three MPS buildings: Hall Elementary School at 1601 N. Aldrich Avenue, Franklin Middle School at 1501 N. Aldrich Avenue, and the MPS Nutrition Center at 812 Plymouth Avenue N. These three buildings are just north of Plymouth avenue and a few blocks east of the RATC. Please see the maps provided below.

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[10] Commercial Solar Energy | Renewable Energy Partners | Twin Cities (renewablenrgpartners.com).
[11] See Project Highlights | Renewable Energy Partners | Twin Cities (renewablenrgpartners.com).

Figure 2: East Plymouth Innovation Corridor, showing RATC at west end and the three MPS buildings that will host North Minneapolis Community Resiliency Hub.

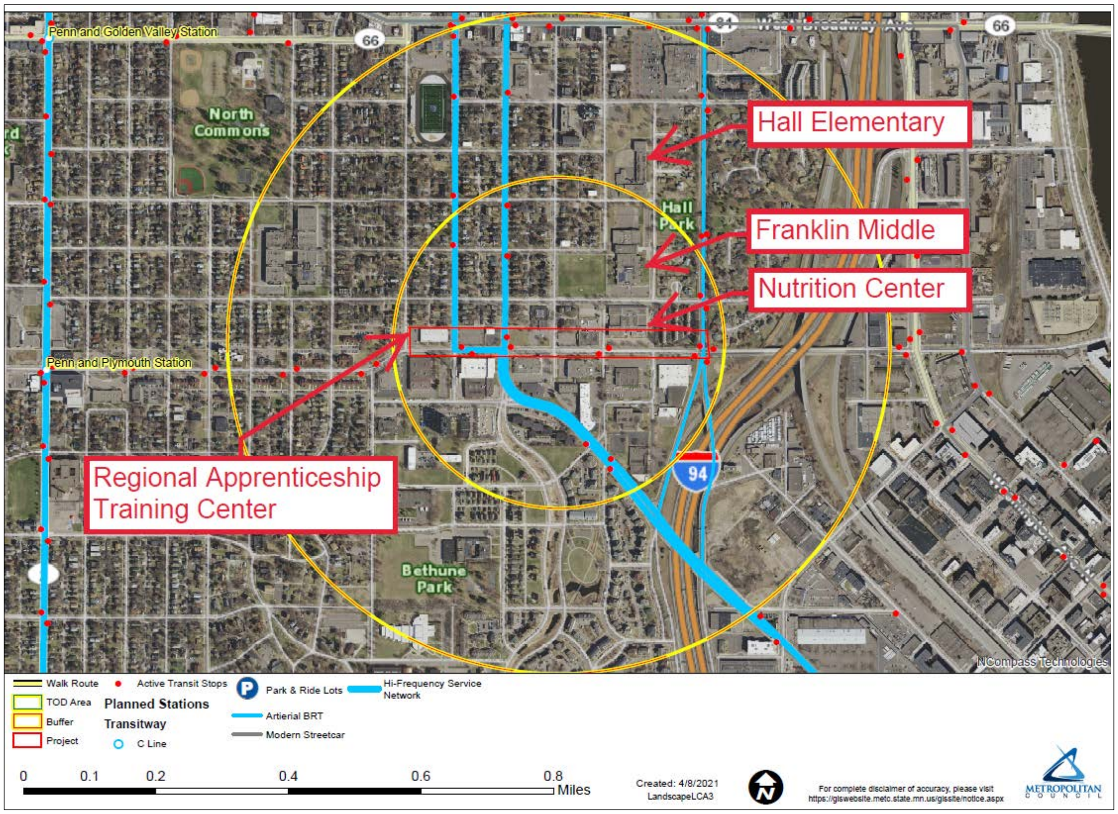

Figure 3: Closer view of North Minneapolis Community Resiliency Hub sites.

Elizabeth Hall	Franklin	Nutrition Center
PV w Roof Aug. Underground Cable	PV Switchgear, Battery, Main Meter	PV Underground Cable

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The project site is within the City of Minneapolis' Northside Green Zone,[12] federal EDA Opportunity Zone[13] and HUD Empowerment Zone.[14] It is also part of the East Plymouth Innovation Corridor.[15]

The area served by the North Minneapolis Community Resiliency Hub is primarily BIPOC and low-income. About 85 percent of Franklin students and 96 percent of Elizabeth Hall students are eligible for Free and Reduced Lunch, compared to 55 percent for MPS overall. The estimated population served by the project is 4,775 residents and 15 businesses, including critical infrastructure such as the Comcast technical center and Hennepin County Service Center.

3. Project Description

The North Minneapolis Community Resiliency Hub aims to create an island-able resiliency hub to provide emergency services to the community. The hub will serve as a base of operations for emergency response, providing essential services such as shelter, cooling center, electricity, food, water, communications, and phone charging in an emergency. The MPS Nutrition Center has capacity to prepare thousands of meals for delivery throughout Minneapolis in the event of an extended outage.

The proposed technologies are:

- 1.1 MW rooftop solar PV, spread across the three buildings
- 1.5 MW / 3 MWh lithium-ion Battery Energy Storage System (BESS)
- Adaptive microgrid controller, designed to balance DER generation with load and provide multi-site balancing in emergencies

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[12] The Northside Green Zone addresses the environmental justice overburden in North and Northeast Minneapolis and designs and implements a plan of action to improve environmental and population health, and social, economic and environmental justice. The Northern Green Zone includes the Northside neighborhoods of Hawthorne, McKinley, and Near-North, and the western portions of the NE neighborhoods of Marshall Terrace, Sheridan, Bottineau, and St Anthony West. See https://lims.minneapolismn.gov/Boards/ngz.
[13] U.S. Economic Development Administration Economic Opportunity Zones are designated economically distressed communities where private investments, under certain conditions, may be eligible for capital gain tax incentives. See https://www.eda.gov/opportunity-zones/.
[14] U.S. Department of Housing and Urban Development Empowerment Zones are designated areas of high poverty and unemployment that benefit from tax incentives provided to businesses within their boundaries. See https://www.hud.gov/hudprograms/empowerment_zones.
[15] *See* https://www.nordiccitysolutions.com/hackathon-challenge-1-north-minneapolis-epic-corridor-energy-and-climate-mitigation/

- Electric gear to interconnect and enable islanding of the three MPS buildings from the surrounding distribution system

The rooftop solar arrays will be financed, owned and operated by REP and its partners, and net metered. The cost of these is not included in this request for certification. REP has committed to explore longer-term community ownership of the solar assets.

The BESS, microgrid controls and all electric gear will be owned and operated by Xcel Energy, and the cost of these items is included in our request for certification. Xcel Energy will manage the BESS to sustain the load of the MPS buildings in the event of an outage, with a primary emphasis on maintaining food preparation and refrigeration at the Nutrition Center and secondary emphasis on providing community gathering sites. In routine, non-outage operation, the RMP assets will be managed to provide grid benefits including peak shaving, load shifting and demand management for the benefit of all customers. We discuss in Section IV how the RMP assets will be dispatched to provide a range of grid services, and in Section VI how the Company will report on lessons learned.

REP has expressed interest in installing a system for remote monitoring of the solar/BESS/microgrid assets at the RATC, to provide additional training for students and visibility of the benefits for the community. We are exploring how to enable such a system within security constraints.

Both Hall Elementary and Franklin Middle currently have diesel generators for emergency backup power. We would aim to reduce or eliminate operation of these generators once the BESS is installed, reducing or eliminating emissions from diesel combustion.

4. Loads and Distribution System Constraints

The table below shows energy data for the three North Minneapolis Community Resiliency Hub buildings in 2020. Note these figures may be lower than typical due to the pandemic.

Table 3: Energy Data – Resiliency Hub Buildings (January – December 2020)

Premise	Total usage (kWh)	Highest monthly peak (kW)	Lowest monthly peak (kW)	Power factor (kVar)
Hall Elementary	408,352	355	112	0.67-0.77
Franklin Middle	998,545	403	215	1
Nutrition Center	1,794,773	537	317	0.86-0.89

The feeder that serves these three Minneapolis Public School buildings is at relatively high capacity in our 2030 forecast, but is not yet at the point where distribution system upgrades are projected to be needed in our current forecast, so no capex deferral value has been assigned to this project in our cost/benefit analysis. If significant load growth were to occur on this feeder – e.g. due to electrification, and/or the new development that REP hopes to support all along the East Plymouth Innovation Corridor – the resiliency investments could take on additional value by deferring conventional distribution system investments that could otherwise be needed, but we have not assumed that here. As part of our reporting summarized in Section VI, we will monitor load growth on this feeder and evaluate whether, over time, the capex deferral value of the RMP technologies grows as a result.

5. Complementary Objectives Addressed by Project

In addition to its direct benefits as a Resilience Hub and distribution system benefits, the North Minneapolis Community Resiliency Hub will reinforce the workforce development and training objectives of the RATC. Project construction will include significant participation from minority businesses and employ BIPOC workers from the neighborhood. The Resiliency Hub will serve as a demonstration and teaching tool for RATC students in solar, battery systems, and microgrid controls, in both the installation and operational phases. Workforce development, career pathways and STEM education will be integrated into the area around the Resiliency Hub which has been designated as the STEM Learning District for MPS. Building a robust STEM learning environment and supporting demonstrations of advanced energy systems are also key components of REP's partnership with the University of Minnesota.

6. Supporters

The North Minneapolis Community Resiliency Hub concept has received support from the Northside Green Zone committee and Northside Residents Redevelopment Council. For the broader initiatives of which the Resiliency Hub is part – the RATC, community solar at North High, and redevelopment of the East Plymouth Innovation Corridor – REP has engaged a network of community-based organizations for community engagement and public education. These engagement partners include North High Site Council, Plymouth Christian Youth Center, Pillsbury United Communities, Juxtaposition Arts, University Research and Outreach Center, Northside Green Zone, Minneapolis Climate Action, and Phyllis Wheatley Center.

The City of Minneapolis and Hennepin County have also provided funding support for the East Plymouth Innovation Corridor. The University of Minnesota has a formal partnership with REP to develop curriculum and training for emerging energy careers in North Minneapolis, as well as hosting an advanced demonstration of solar-plus-storage with microgrid controls at the RATC.

B. Sabathani Community Center

1. Project Lead and Partners

Sabathani Community Center was established in 1966 with a mission to provide people of all ages and cultures with essential resources that inspire them to improve their lives and build a thriving community.[16] Sabathani has served as a pillar for community identity, empowerment, and social change for over 50 years. Sabathani serves over 43,000 community members in South Minneapolis each year with community-oriented, culturally sensitive services and programming including:

- Neighborhood Food Shelf, a permanent emergency food security resource distributing over 1 million pounds of food to approximately 10 percent of Minneapolis' population annually
- Senior Outreach, providing health and wellness services, community service and social engagement, and culturally specific outreach services to seniors
- Community-based Health and Wellness: services targeting high-risk, under-resourced populations to help address disparities in health outcomes
- Clothing Closet to provide clothing and household goods to low-income individuals and families
- Senior Housing Development Project, a 48-unit residential development providing affordable housing for seniors 55 and older, slated to open October 2021

[16] This section is derived from Sabathani Community Center's website and Sabathani's response to Resilient Minneapolis Project call for applications, April 2021.

- Community Businesses: a lease program offering commercial space for rent at affordable rates to 20+ minority-owned businesses and nonprofits including African American, East African, and Latinx-owned. Tenants include Community Action Partnership of Hennepin County, Multiple Choice Adult Day Care, Somali Family & Youth Services, Connections to Independence (support for youth in foster care), Kids Care Zone (daytime childcare), Out Front MN LGBT, Narcotics Anonymous, Association for Training on Trauma and Attachment in Children (ATTACh), and various mental health providers including licensed social workers, therapists, and psychologists who offer free, sliding-scale, and multilingual care services to clients.

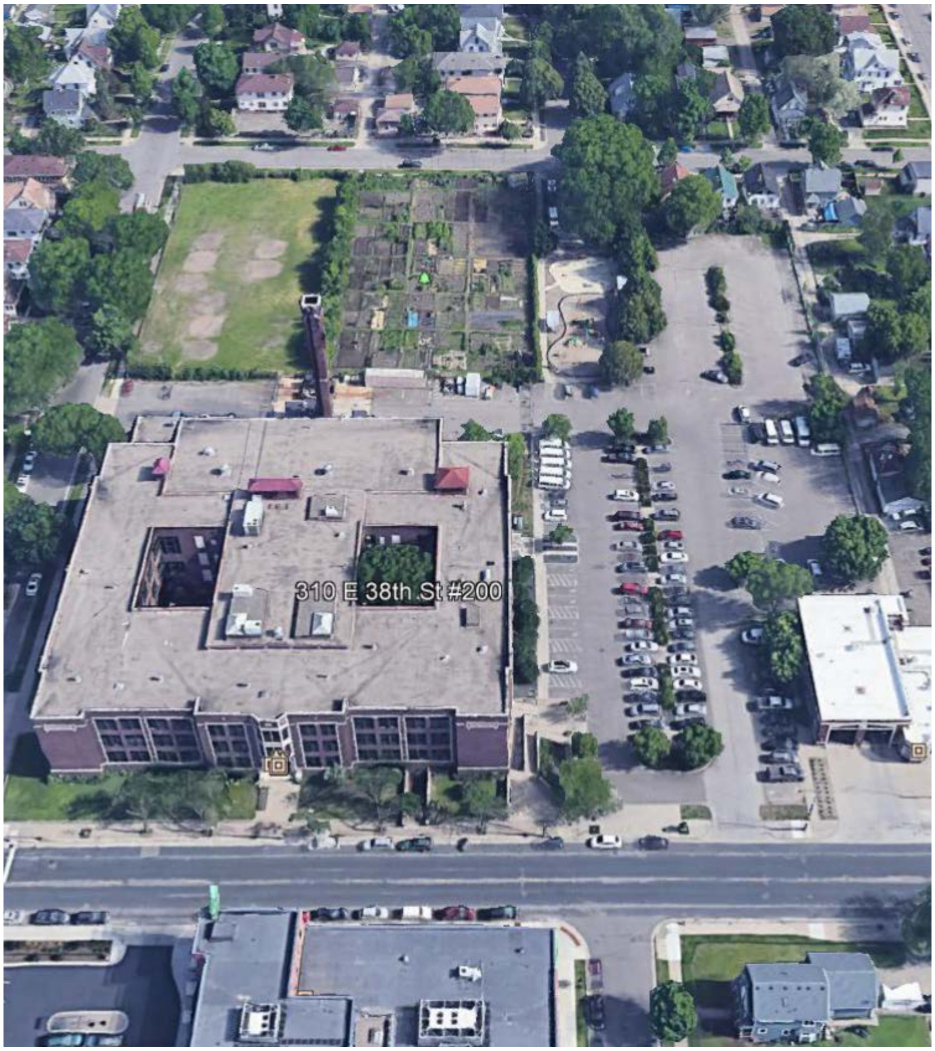
The population Sabathani serves are 87 percent BIPOC, and 80 percent live below the poverty line in the most disinvested neighborhoods of South Minneapolis (Central, Bryant, Phillips, and Powderhorn). Sabathani's leadership and the majority of staff and board members are people of color.

Center for Energy & Environment (CEE) has partnered with Sabathani over the past several years for energy assessment, redesign and retrofit options. CEE provided a One-Stop Efficiency Shop assessment of potential lighting upgrades at Sabathani. Elevate Energy, based in Chicago, has provided Sabathani a preliminary solar resource analysis, and will continue to engage to support the solar component of this project.

2. Location and Beneficiaries

Sabathani is located at 310 East 38th Street in South Minneapolis. Sabathani estimates the area served by a community resiliency hub would extend from Nicollet Avenue on the West to Bloomington Avenue on the east, and from 36th Street on the north to 40th Street on the South, with an approximate population of 72,000 people and over 30 businesses.

Figure 4: Sabathani Community Center



Sabathani is at the core of the 38th Street Thrive Cultural District approved by the Minneapolis City Council in early 2021, with a vision to "continue the legacy and heritage of a deeply rooted African-American community by preserving our economic vibrancy, creative identity, and affordability that strengthens the vitality, resilience and partnership of the people who live and work in the district."[17] Notably, the 38th Street Thrive strategic plan envisions creating a Resilience Hub at Sabathani to "enhance our ability to recover from traumas, disturbances, shocks or stresses due to climate changes, power outages, medical outbreaks, fires or other human-caused disasters…" and "serve as a facility in supporting the community before, during, and after disruptions by 1) mitigating climate change using resilient energy systems, 2) providing

[17] *Thirty-Eighth Street Thrive Cultural District Strategic Development Plan*, February 2021.

opportunities for the community's benefit with a solar farm cooperative, 3) providing local emergency management and communication, 4) coordinating the distribution of essential resources - shelter, water, food, medical supplies etc. when needed, and 5) creating a mobility hub with bike lanes, bus transit, bike parking and wheelchair accessibility, etc."[18] Funding through the RMP – while it cannot support every one of these objectives – would enable Sabathani to move forward on key aspects of this vision to become a Resilience Hub for the 38th Street Thrive Cultural District.

3. Project Description

Sabathani's RMP application notes that "the resilience of the surrounding community is directly tied to the health and resilience of the Sabathani Community Center and the services that it offers... Sabathani's uninterrupted operations are critical to community resilience. The technologies proposed below… will serve as a demonstration to the surrounding community as well as all of Xcel Energy's customers of how even older buildings such as Sabathani can contribute to a clean energy future and be made significantly more resilient in the face of future extreme weather events. They will also provide grid services on a daily basis, including peak shaving, voltage control, and demand response."[19]

The proposed technologies are:

- 240 kW AC rooftop solar PV system, sized based on a preliminary solar assessment from Elevate;
- 1 MWh (500 kW, two hour) BESS; and
- Electric gear to interconnect and enable islanding of Sabathani from the surrounding distribution system.

The BESS, microgrid controls and all electric gear will be owned and operated by Xcel Energy, and the cost of these items is included in our request for certification. Xcel Energy will manage the BESS to sustain critical loads at Sabathani in the event of an outage, including food preparation, community sheltering spaces, medical and emergency services, etc. In routine, non-outage operation, the RMP assets will be managed to provide grid benefits including peak shaving, load shifting and demand management for the benefit of all customers.

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[18] Ibid. at pp. 40-41.
[19] Sabathani Community Center response to Resilient Minneapolis Project call for applications, April 2021.

In Sabathani's case it is important to note that the proposed resiliency investments (i.e. solar, BESS, microgrid) are only one piece of broader energy objectives that are centered on improving energy affordability in order to continue delivering Sabathani's core services and offering affordable rent to BIPOC-owned tenant businesses. Sabathani occupies a 100-year old building that is inefficient and has very old heating, cooling and lighting systems, and currently pays about $18,000 per month for gas and electric service. In its RMP application, Sabathani proposed measures to upgrade its HVAC system, make the building more efficient, reduce energy costs, and reduce emissions. These included:

- Variable refrigerant flow (VRF) system, capable of providing both heating and cooling, to replace two 55-year old natural gas fired steam boilers and 104 thirty-year old in-room ceiling mount air conditioning units. Sabathani is evaluating either a geothermal (water-source) VRF system, which they believe would allow for complete electrification of the building's heating systems since it would be capable of meeting the building's heating loads even on the coldest winter days, or an air-source VRF system, which would be less expensive but could still meet much of Sabathani's heating load (and all of the cooling). Sabathani is also open to other efficient HVAC options. The Company is working with Sabathani to support an HVAC engineering study to explore these options.
- Building envelope efficiency measures, reducing energy loss and both electricity and gas utility bills. Sabathani proposes to insulate to R-30 and air seal under the roof.
- Lighting retrofits, replacing T8 fluorescent lights throughout the building with LEDs. These lighting retrofits are estimated, based on a One-Stop Efficiency Shop assessment, to provide 107 kW in demand savings, which will significantly lower total load and allow the BESS to sustain the building's load for longer during an outage. The Company is working with Sabathani to support lighting retrofits through CIP rebates and Minneapolis Green Cost Share funding.
- Building automation system, tying together the various installed technologies and providing the controls necessary to operate Sabathani efficiently and enable it to be grid interactive (schedule heating and cooling loads, lighting schedules, providing demand response, reducing demand to critical loads during an outage)

Note the costs of the measures in the list above are not included in this request for certification, since they are not directly tied to IDP objectives. The Company understands the priority Sabathani places on these investments, however, so is working actively with Sabathani to identify ways to fund all or a portion of them through rebates from the Company's Conservation Improvement Program (CIP) offerings, City of Minneapolis Green Cost Share funds, and other external funding.

4. *Loads and Distribution System Constraints*

Sabathani is a 188,257 sq. ft. building with a current peak annual load of 330 kW. Over the last three years, monthly peak demand has ranged from almost 350 kW to as low as 100 kW during autumn months of 2020 (presumably affected by mild temperatures combined with reduced operations during COVID). Annual energy use pre-pandemic was over 1 million kWh.

The feeder that serves Sabathani is approaching full capacity in our 2030 forecast, but is not yet at the point where distribution system upgrades are projected to be needed in our current forecast, so no capex deferral value has been assigned to this project in our cost/benefit analysis. If significant load growth were to occur on this feeder – e.g. due to electrification or other factors – the resiliency investments could take on additional value by deferring conventional distribution system investments that could otherwise be needed, but we have not assumed that here. As part of our reporting summarized in Section VI, we will monitor load growth on this feeder and evaluate whether over time the capex deferral value of the RMP technologies grows as a result.

5. *Complementary Objectives Addressed by Project*

Sabathani sees the RMP in the context of its larger environmental and racial justice objectives. Sabathani notes, "the pandemic combined with George Floyd's murder only three blocks away and righteous protests this past year laid bare the systemic racism, power dynamic, and economic disparities which have plagued our community for decades. We cannot return to business as usual…" Sabathani sees its participation in the RMP as investing "in the communities that have been hardest hit by these inequities and committing to fight for a new future where wealth-justice, a clean energy transition, resilient communities and opportunity are built from the ground up by and for the people who live and thrive in this neighborhood."[20]

The South Minneapolis neighborhoods served by Sabathani bear disproportionate environmental and health burdens, including some of Minneapolis's highest asthma

[20] Sabathani Community Center response to Resilient Minneapolis Project call for applications, April 2021.

rates among children according to the Minnesota Department of Health,[21] and are expected to experience disproportionate impacts from climate change-related events. Sabathani's efforts under the RMP begin to address these inequities by reducing pollution locally, improving community resiliency to climate change, and providing a secure gathering space with reliable power to continue providing services in the case of weather-related outages.

Finally, Sabathani is partnering with the City of Minneapolis to launch a solar PV training program that will focus on job training for a diverse workforce. Reimagining and upgrading Sabathani's inefficient building would not only support Sabathani but also provide a city-wide demonstration and training site for renewable energy technologies.

6. Supporters

In addition to its formal implementing partners CEE and Elevate, Sabathani enclosed with its original RMP application letters of support from Minneapolis City Council Vice President Andrea Jenkins and Institute for Market Transformation. Sabathani's RMP activities are strongly supported by these partners as a way to create a model for community resiliency, energy affordability and equity.

C. Minneapolis American Indian Center

1. Project Lead and Partners

The Minneapolis American Indian Center (MAIC), built in 1975, is focused on serving a large and tribally diverse urban American Indian population, numbering well over 35,000 in the eleven-county Minneapolis-St. Paul metro area.[22] MAIC hosts over 10,000 visitors annually, and engages 43 different American Indian tribes along Minneapolis' American Indian Cultural Corridor. MAIC serves as a central meeting location for urban American Indian organizations, community-based organizations, educational institutions, and entrepreneurs from throughout South Minneapolis, surrounding neighborhoods and the greater Twin Cities.

MAIC's programs and services are predominantly focused on Native American children, youth, adults, elders, and families. Most participants are low-income and

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[21] https://www.health.state.mn.us/diseases/asthma/data/quickfacts.html

[22] This section is derived from MAIC's website and response to Resilient Minneapolis Project call for applications, April 2021.

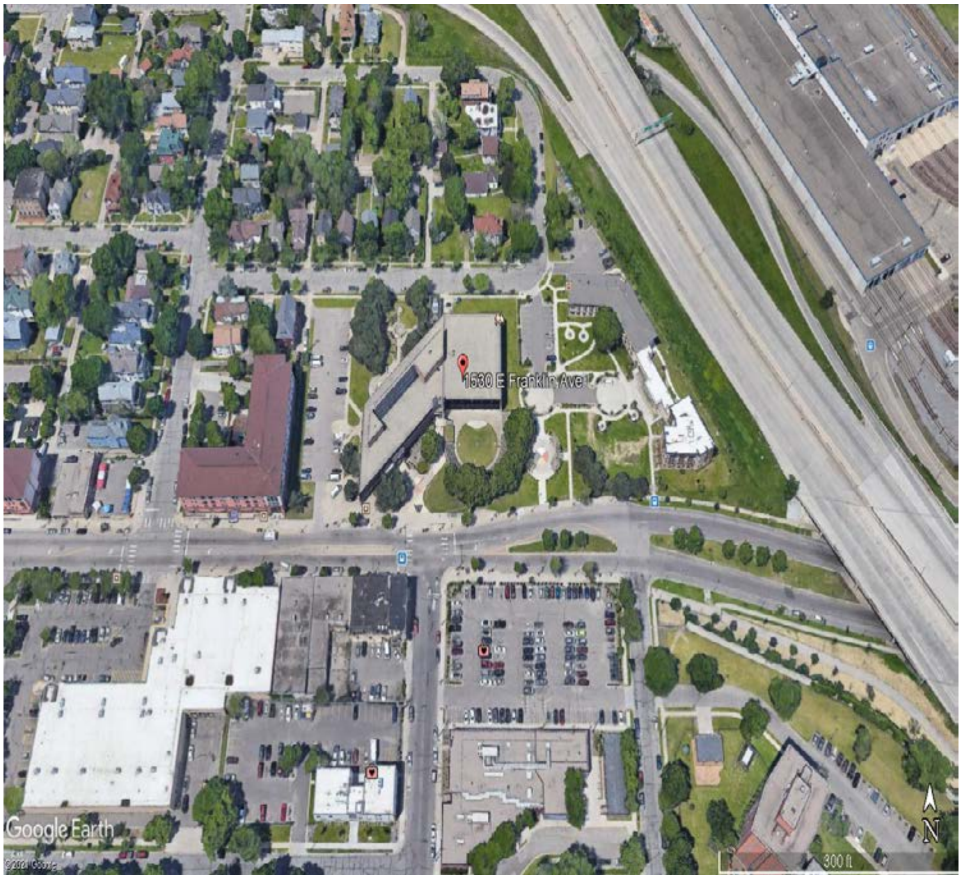
experience significant opportunity gaps in health and wellness, education, access to basic needs and resources, housing, living-wage jobs and career pathways, civic and community engagement, and long-term economic stability and prosperity. MAIC's culturally supportive programming engages urban Native Americans within the context of their own traditions and experiences, promoting positive outcomes and addressing disparities between the Native and mainstream populations. MAIC also functions as a cross-cultural bridge by providing a destination for non-Native people to attend events, seminars, performances, and exhibitions. In particular, its Gatherings Café, Two Rivers Art Gallery and Woodland Crafts Gift Shop draw many diverse visitors to engage in learning and understanding about Native values, traditions and philosophy, providing learning for visitors who would otherwise likely have limited interaction with the broader American Indian community.

MAIC's partners for its planned renovation are Cuningham Group, serving as lead architects under the direction of Sam Olbekson, Native architect and MAIC Board Chair; Emanuelson-Podas Consulting Engineers, serving as mechanical/electrical engineers for the project, with experience in solar arrays and emergency power generation; and Crowley, White, Helmer & Sevig, Inc., who are assisting with MAIC's capital campaign.

2. *Location and Beneficiaries*

The MAIC is located at 1530 E Franklin Avenue, in the heart of Minneapolis's American Indian Cultural Corridor. The approximate population served is 22,015, with an approximate business count of 500.

Figure 5: Minneapolis American Indian Center



3. Project Description

The energy and resilience activities at MAIC fall within a planned renovation and expansion of their existing space, roughly doubling its size from about 30,000 sq. ft. currently to about 65,000 sq. ft. This will update the existing spaces, improve the sustainability and efficiency of the building, and create a broad array of new multi-use spaces for programs, service delivery and events. The current plan is to begin construction in late spring/early summer 2022, which aligns well with the RMP timeline.

MAIC's proposed RMP investments include:

- Rooftop solar PV system of around 200 kW, installed on the approximately 35,000 sq. ft. of new roof space on the addition, with the possibility of additional capacity on existing roofs contingent on structural and shading constraints;

- 1 MWh (500 kW, 2 hour) BESS;
- Back-up natural gas/diesel generator for emergency power; and
- Electric gear to interconnect and enable islanding of MAIC from the surrounding distribution system.

MAIC is working with Xcel Energy's Energy Design Assistance program to finalize key aspects of the upgraded HVAC systems, thermal envelope, efficient lighting, food preparation, and building automation system. The renovation is being planned to meet Minnesota's B3 building standards. These costs are not included in this certification request. The Company is working with MAIC to identify ways to help fund those activities through CIP rebates and/or external cost sharing.

4. Loads and Distribution System Constraints

MAIC is an approximately 30,000 sq. ft. building with a current peak annual load of about 250 kW. Over the last three years, monthly peak demand has ranged from 250 kW in summers to a low of around 100 kW. Annual energy use pre-pandemic was almost 800,000 kWh. With the expansion to 65,000 sq. ft., MAIC's peak load is forecast to grow to about 400 kW.

The feeder that serves MAIC is nearly at full capacity in our 2030 forecast, and is the most heavily loaded feeder of the three RMP sites. It is approaching, but has not yet reached, the point where added load could require distribution system upgrades. Note that this forecast still reflects MAIC's current average annual peak load of 250 kW; the projected increase to 400 kW when the MAIC expansion is complete would bring this feeder even closer to full capacity. This means any subsequent load growth on that feeder – e.g. due to electrification or other factors – could trigger the need for distribution system upgrades. The load reduction created by the proposed resiliency investments at MAIC could help defer such costs. However, because this feeder is not yet overloaded in our 2030 forecast, we have conservatively not included any capex deferral value for this project in our cost/benefit analysis. As part of our reporting summarized in Section VI, we will monitor load growth on this feeder and evaluate whether over time the capex deferral value of the RMP technologies grows as a result.

5. Complementary Objectives Addressed by Project

The RMP project will support community-identified needs for the facility as a core gathering place for cultural, social, arts, and physical fitness activities for the Native community, reduce operating costs, enhance MAIC's ability to generate revenues, and improve visibility, access and security.

MAIC's broader renovation aims to create a more livable community in South Minneapolis and increase opportunities for disadvantaged and underprivileged Native people to thrive. MAIC will modernize its 1975 building and add a one-level addition, creating a more welcoming community space. The Gatherings Café, Two Rivers Art Gallery and Fitness Center will be relocated to be more accessible to clients and the public while increasing income generation. MAIC will add new meeting spaces for programming and for rent by external organizations and groups, as well as create coworking office space for rent by individuals, non-profits and businesses.

Ultimately, MAIC's goal is to create a lasting impact along the American Indian Cultural Corridor and Franklin Avenue Commercial Corridor, contributing to neighborhood vitality and providing the urban American Indian population and visitors with a state-of-the-art facility that stimulates inclusive local economic growth and sustainable, resilient community development, while firmly establishing investment in strategic, community-led placemaking.[23] The energy activities proposed here fit within that broad vision – reducing costs, improving resilience, and building wealth for the Native community. The figure below shows a rendering of the proposed renovation once complete.

Figure 6: Exterior Study of Completed MAIC Renovation.

[23] MAIC response to Resilient Minneapolis Project call for applications, April 2021.

IV. COSTS AND BENEFITS

In this section, we summarize the anticipated costs of implementing the RMP; provide a narrative summarizing both quantified and non-quantified benefits; and provide a cost/benefit analysis.

A. Cost Estimates

The following table summarizes estimated costs for the three RMP sites. Note these are preliminary estimates, to be refined with more detailed design work and vendor estimates once the Company issues Requests for Proposal (RFPs) in 2022. Costs of rooftop PV systems will be borne by the RMP hosts and/or their financial partners. Costs included in this request for certification are comprised of capital cost of the BESS, interconnection costs at each site (medium voltage work, site preparation, islanding switch, etc.), and systems integration, security and communications, plus annual O&M costs.

Table 4: Cost Estimates for each RMP Site (preliminary)

	North Minneapolis Community Resiliency Hub	Minneapolis American Indian Center	Sabathi Community Center	Total
A. Capital Costs				
Battery Energy Storage System	$ 2,123,123	$ 940,163	$ 940,163	$ 4,003,449
Islanding Switch (ATO)	$ 241,800	$ 241,800	$ 241,800	$ 725,400
Medium Voltage work	$ 128,464	$ 56,668	$ 112,964	$ 298,096
Site Evaluation/Surveying/Prep/Etc.	$ 211,420	$ 211,420	$ 211,420	$ 634,260
Business Systems Integration	$ 330,274	$ 330,274	$ 330,274	$ 990,822
Project Management and labor	$ 236,890	$ 220,075	$ 282,075	$ 739,040
Miscellaneous	$ 639,396	$ 382,835	$ 525,579	$ 1,547,811
Total capital	$ 3,911,367	$ 2,383,235	$ 2,644,276	$ 8,938,878
B. Annual O&M Costs				
Annual O&M	$ 23,861	$ 19,091	$ 19,091	$ 62,043

B. Benefits Discussion

The solar, BESS, and microgrid controls installed at the three RMP sites will deliver multiple benefits. These include benefits to the host organizations themselves, to the communities they serve, benefits for grid modernization, and learnings that will benefit the Company's customers overall as these technologies become more common in the coming years. Some of these benefits are quantifiable in dollar terms, which we do in the following section; others are non-quantified but no less important. We urge the Commission to consider the non-quantified benefits as well, even though they are not part of the benefit:cost ratio presented in the next section.

Please note that while the RMP investments can provide multiple grid services, not all services can be performed simultaneously; rather, they would be called upon individually as determined by current electrical system conditions. One of the key benefits of the RMP, therefore, is learning about how to optimize these services, recognizing not all can be delivered at once. That learning will benefit all the Company's customers, not just our three partner organizations.

1. Quantified benefits

The following benefits of the RMP grid modernization investments are quantified in dollar terms in the next section.

- *Backup power and resilience*. Through the use of inverter-based technology with grid-forming capability, the BESS systems will be able to provide multi-hour backup power to the relevant facility's load in the event of a utility power outage. This service is capable of extending to a multi-day outage event given the availability of on-site solar and/or back-up generators. The percentage of total energy storage capacity reserved for backup power will be configurable based on building load, available generation, and other system conditions (e.g., weather, system peaking, etc.). A relatively short outage (up to 4-5 hours, depending on the building loads and state of charge of the BESS) could be covered by the BESS alone, while longer outages could be covered by recharging the BESS with solar generation, curtailing non-critical loads and limiting building energy demand to those loads critical for resiliency, and as a last resort running back-up generators.
- *Bulk system capacity*. Ability to dispatch the BESS during peak electrical system days based on a signal from the Company.
- *Local distribution system support*. Ability to dispatch the BESS to reduce local feeder peak.
- *DER integration*. Ability to increase the amount of distributed generation that can be hosted on a particular feeder by creating a load (the BESS) for excess solar generation that would otherwise have to be curtailed.

- *Non-wires alternative*. Creating more "head room" for load growth on a feeder that is nearing its capacity, thus deferring capital expenses for conventional distribution system upgrades that would otherwise be needed to handle the anticipated load growth. As described above, our quantitative cost/benefit analysis conservatively includes no capex deferral value for any of the RMP sites, even though some are nearing full capacity such that additional load growth could necessitate distribution system upgrades in the absence of the RMP investments.
- *Arbitrage*. Ability to set predefined or ad hoc charge/discharge commands in order to take advantage of daily electricity price differentials and maximize the monetary benefit of price variations.
- *Emission avoidance*. Solar generation, and the ability to store that generation in the BESS and inject it into the grid during hours when solar is not generating, will displace other generation resources, a portion of which are fossil resources emitting carbon dioxide and criteria pollutants. Avoided emissions have societal benefit (avoided monetized damages to society) per the environmental externalities framework used by the Commission.

While the RMP investments will support community resiliency in the event of an extended outage, such outages are today rare – i.e., low-probability but high-impact events. Considering this, the RMP systems will be managed on a day-to-day basis to provide the multiple grid benefits listed above, while reserving enough BESS capacity for an unanticipated outage (and increasing the BESS reserve capacity if a severe weather event is anticipated with some advance notice). This will also provide valuable opportunities to learn how best to operate solar/BESS/microgrid systems on a routine basis, optimize these systems to deliver multiple benefits, and learn which services can realistically be delivered simultaneously and which exclude delivery of others. These learnings will benefit all our customers as these systems become more common.

2. *Non-quantified benefits*

The RMP investments also provide a range of benefits that we did not attempt to quantify in dollar terms:

- *Training and job creation*. The RMP projects will create training and energy workforce diversification opportunities, including preparing BIPOC individuals for clean energy apprenticeships and careers. These include:

  - The North Minneapolis Community Resiliency Hub will provide training via its RATC for installation and operation of solar, BESS and microgrid equipment, as well as partnering with the University of Minnesota on curriculum development and to provide research opportunities for university students.
  - Sabathani is working with the City of Minneapolis to launch a solar PV training program that can use the new solar and BESS assets for training purposes.
  - All RFPs issued by the Company to select vendors for RMP design and installation will apply supplier diversity criteria to give preference to women- and minority-owned businesses. The solar assets will be procured by the host organizations themselves, so the Company does not have direct control of vendor selection there, but all three organizations are likely to prioritize working with BIPOC-owned businesses and creating training opportunities.
- *Value of learning for future resiliency and/or NWA projects*. Implementing the RMP at these three sites will provide learnings that can benefit all the Company's customers as solar, battery storage, and microgrid technologies become more prominent on our distribution system in the coming years. Specifically, we expect that more communities will be interested in resiliency investments, and it will be important to better understand how to optimize these projects to deliver multiple services on a routine, non-outage basis as described in the foregoing section. In Section VI we propose a reporting mechanism to track and share lessons learned.
- *Energy equity objectives*. We here use energy equity as a general term to capture a broad set of objectives – clearly stated in the mission and vision statements of Renewable Energy Partners, Sabathani and MAIC – around enhancing equitable access to clean energy alternatives, using clean energy to build community wealth, energy sovereignty, improving energy affordability and reducing energy burden, and advancing environmental justice in communities historically disproportionately impacted by pollution and marginalized in energy decision-making. We do not attempt to quantify these benefits, but we acknowledge them as real concerns that the RMP initiative can help address.

C. Cost/Benefit Analysis

The Company conducted a CBA that uses the costs from section A above, and estimates the monetary value of resilience back-up power, capacity, generation savings, carbon avoidance, and arbitrage. The table below the results of that CBA, including benefit:cost ratios for each project and for the RMP overall. The CBA is included as a workpaper to this filing.

Table 5: Cost and Benefit Summary Table for RMP

	Units	North Minneapolis Community Resiliency Hub	Sabathani Community Center	Minneapolis American Indian Center	Aggregate
COSTS					
Capital					
Total Capital Cost	$	$3,911,367	$2,644,276	$2,383,235	$8,938,878
O&M					
Annual O&M Cost	$	$23,861	$19,091	$19,091	
NPV of Annual O&M Costs (10 years)	$	$172,662	$138,146	$138,146	$448,953
Total Capital and O&M	**$**	**$4,084,029**	**$2,782,421**	**$2,521,381**	**$9,387,831**
BENEFITS					
Resilience/Value of Lost Load	$	$575,076	$575,076	$460,060	$1,610,212
Bulk System Capacity Value	$	$111,344	$54,384	$65,643	$231,371
Generation & Carbon Emissions		$133,138	$25,417	$22,997	$181,551
Arbitrage	$	$62,174	$3,173	$12,417	$77,764
Lifetime Benefit	$	**$881,732**	**$658,050**	**$561,117**	**$2,100,899**
BENEFIT:COST RATIO		**0.22**	**0.24**	**0.22**	**0.22**

We note that the benefit-to-cost ratios above are not particularly high. We understand the priority placed by the Commission on advancing development of distributed energy systems that combine solar and energy storage to create multiple grid benefits. Also, the emergency back-up role these BESS projects support in these applications could support communities in times of significant or prolonged duress, which is inherently hard to value, as discussed above. Therefore, we do not believe these low benefit-to-cost ratios are a cause for concern here as they might be in a different context.

Also, we reiterate that, while some of the benefits discussed in Section IV.B can be quantified in dollar terms, others are equally important but more difficult to quantify. Since all costs are quantified, but only a subset of benefits are quantified, the benefit-to-cost ratios presented in this section reflect an incomplete picture of the overall benefit of the RMP projects to our communities and customers.

D. Alternatives Analysis

Among the certification requirements is a description of the available alternatives to meet a project's intended objectives.[24] The intended objectives of the RMP are directly linked to the statutory criteria for IDP investments by utilities operating under multiyear rate plans[25]: modernizing the distribution system to improve reliability in an extended outage, as well as increasing energy conservation opportunities through control technologies, energy storage and microgrids, and technologies to enable demand response (among a range of other grid services as discussed in Section IV.B). Implementing this pilot will enable Company learnings around managing solar/battery/microgrid systems to deliver multiple grid benefits.

Because the RMP is essentially a pilot project, rather than a project addressing an immediate inadequacy or deferring a conventional distribution system upgrade, the alternative the Company would implement if the Commission disapproves this request is a no-action alternative.

V. IMPLEMENTATION SCHEDULE

If the Commission grants this request for certification, the Company will work with our community partners to implement the following steps as quickly as feasible, targeting projects coming online by summer 2023. The schedule below assumes Commission approval no sooner than May 2022, so most other steps cannot start until summer 2022. It also assumes a 4-6 month lead time for BESS delivery after placing an order. Note the schedule below focuses only on the period up to the in-service date of the RMP projects, not the subsequent operations and learning period which will extend through at least the ten-year assumed life of the battery systems.

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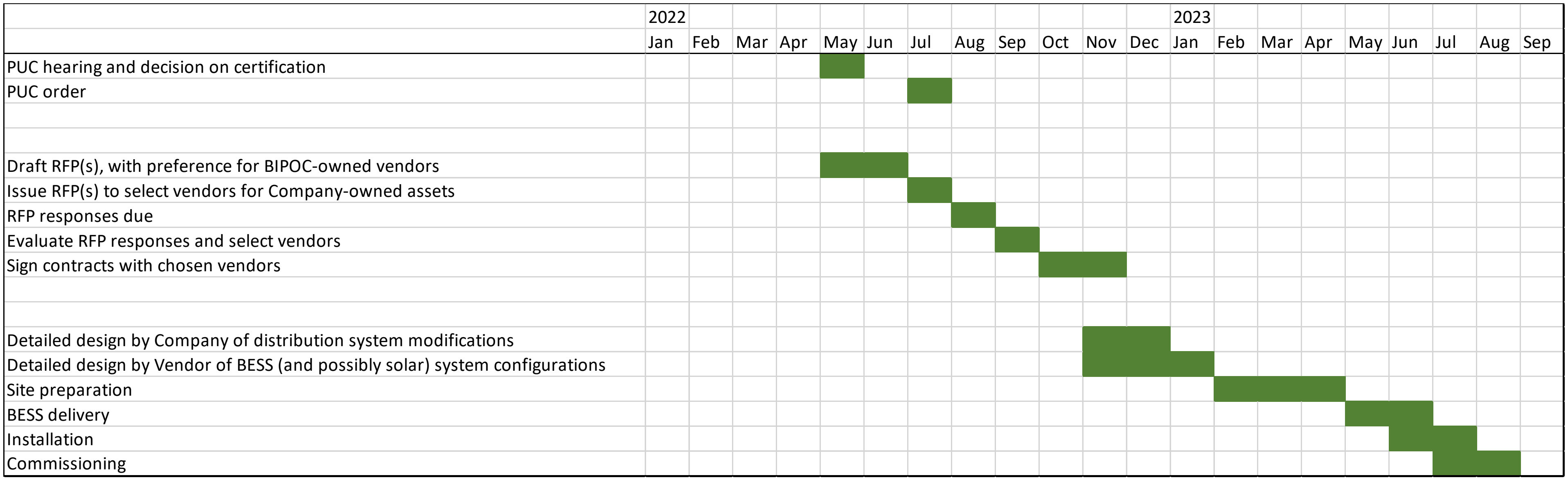
[24] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program* and *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report*, Dockets E-002/M-17-775 and E-002/M-17-776, Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request (Aug. 7, 2018) at 9.
[25] See Minn. Stat. §216B.2425, subd. 2 (e).

Table 6: Gantt Chart for Implementation in 2022-23



VI. REPORTING LESSONS LEARNED

Because the RMP is a pilot project, the Company feels it is important to provide a formal mechanism for reporting lessons learned. We propose an annual reporting schedule to update the Commission and stakeholders on RMP progress and lessons learned. These reports would include both progress on the initial installation and commissioning of the RMP projects, and lessons learned in the operations phase as the projects are managed to provide the grid services as summarized in Section IV. We propose the following schedule, but are open to a different schedule or reporting approach if the Commission prefers.

- Initial Progress Report (December 2022)

As of December 2022, the RMP systems will not yet be installed, so this will be a report on progress toward commercial operation. The report will summarize the status of agreements with RMP project hosts, RFP(s) for battery systems, methods used to support women- and BIPOC-owned firms in the RFP stage, contracts with battery vendors, and expected delivery of battery systems at each site. The report will include detailed engineering designs and more refined cost estimates.

- Construction Progress Report (December 2023)

This will be the first report after installation and the commercial operation date (COD) of the RMP projects. We will report on those installations, hurdles encountered and solutions reached, any significant changes to the initial project plan, actual costs and any material deviations from the cost estimates in the prior report. The report will also summarize the first few months of operation of the solar/battery/microgrid systems.

- Annual Operations Reports (each December, 2024 through 2026)

In annual reports filed at the end of each year, the Company will report lessons learned from operation of the solar/battery/microgrid systems to deliver resiliency and a range of other grid services as summarized in Section IV. These reports will be the primary mechanism for compiling lessons learned to apply to similar projects as they become more common on our distribution system. Proposed report contents include but are not limited to:

- Number and duration of islanding events for each project;
- Battery state of charge at the time of islanding events;
- Use of on-site renewable and non-renewable generation during islanding events;
- Summary of any unplanned outages, technical failures or maintenance issues;
- Summary of how batteries were dispatched over the course of the year, including dispatch for arbitrage, system peak, and feeder peak, and associated non-quantifiable benefits realized from dispatch;
- Summary of monetary benefits and emission reductions related to the projects, to the extent such data can reasonably be isolated to the projects collectively or individually;
- Load growth on the feeders serving each RMP site, and whether over time these projects grow in their ability to serve as Non-Wires Alternatives deferring capital expense for conventional distribution system upgrades;
- Summary of interactions and feedback from host communities: how well are the RMP projects serving the core needs of our partner organizations? What changes to the project design could serve those needs better?; and
- Summary of lessons learned from the operations of the RMP projects to date.

VII. REQUEST FOR CERTIFICATION

We respectfully request that the Commission certify our proposal to implement the RMP at the North Minneapolis Community Resiliency Hub, Sabathani Community Center, and Minneapolis American Indian Center, with estimated total costs as summarized in section IV.A. If this request for certification is granted, the Company would expect to seek cost recovery via the Transmission Cost Recovery (TCR) Rider.

In accordance with Minn. Stat. §216B.2425, utilities operating under multiyear rate plans must identify in biennial reports:

> …investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.[26]

The RMP is a project eligible for certification under the above statutory criteria in that it:

[26] Minn. Stat. §216B.2425, subd. 2 (e).

- Helps to modernize the distribution system by enhancing reliability and improving security against physical threats, including but not limited to physical threats (i.e. extreme weather events) that are anticipated to increase in frequency and severity due to a changing climate; and
- Provides energy conservation opportunities and facilitates communication between the utility and its customers through the use of control technologies, energy storage and microgrids, and other innovative technologies. These technologies will enable demand response as well as other grid services, as described in section IV.B, when dispatched on a routine, non-emergency basis. Managing the solar, battery and microgrid technologies to optimize these grid services will provide learnings to the benefit of all the Company's customers. Managing the same assets to provide power for critical services in the event of an extended outage will support community resiliency hubs in disproportionately impacted communities.

Beyond these statutory criteria for IDPs, the RMP delivers a broad range of benefits as summarized in section IV, including greater DER integration, emissions avoidance, workforce training and diversification, enhancing energy affordability, and environmental justice.

We note that we did not perform a rate analysis of this proposal because we expect the total dollars invested to be under $10 million, and thus any rate impacts to be minimal. Additionally, until the specific projects are budgeted, we are unable to calculate a cost-of-service analysis. We are happy to perform this analysis after the Commission makes its certification decision and the project components are finalized.

APPENDIX I: STAKEHOLDER ENGAGEMENT

In this Appendix, we discuss our stakeholder engagement leading up to this IDP.

IDP Requirement 2 requires the following:

> *Xcel should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.*
>
> *At a minimum, Xcel should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.*

We held an overall IDP Stakeholder Workshop from 9:00 a.m. to 12:00 p.m. on September 17, 2021 with the objective to share and obtain feedback on key aspects of our upcoming IDP filing. We submitted the presentation materials and a link to the recording of the Workshop to the Commission in this docket.[1] We provide a summary of the IDP Workshop below.

In April 2021, we also held two non-wires alternatives (NWA) workshops with stakeholders. We held the NWA workshops in compliance with Order Point No. 6 of the Commission's July 23, 2020 Order in Docket No. E002/M-19-666, which required the Company to engage stakeholders in further advancing our NWA analysis, including the screening criteria, analysis methodology and assumptions, and evaluation parameters. We also held these workshops to be responsive to the Company's commitment in our 2019 IDP proceeding to include a broader set of values and revenue streams in future NWA analyses.[2] We discuss these workshops in more detail in *Appendix F: Non-Wires Alternatives Analysis*, and also provide a summary of the outcomes and how we incorporated stakeholder feedback into our 2021 NWA analysis and recommendation for our 2022 NWA analysis.

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[1] *See* Xcel Energy Letter dated September 23, 2021 and corrected link to the workshop recording dated October 6, 2021 in Docket Nos. E002/M-19-666 and E002/M-21-694.
[2] *See* July 23, 2020 Order in Docket No. E002/M-19-666 at page 8.

I. OVERALL IDP WORKSHOP – SEPTEMBER 17, 2021

We announced the Workshop in an August 3, 2021 filing in our 2019 IDP docket. We also emailed the announcement to our interested parties list, which includes over 500 individuals that have expressed interest in the IDP, our integrated resource plan, our hosting capacity analysis, or who are interested parties or participants in various solar development dockets or workgroups. Approximately 21 individuals attended this workshop.

The Workshop slides are available here:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={80C3137C-0000-C318-A916-0E1D423E41F6}&documentTitle=20219-178196-01

The Workshop recording is available here: https://youtu.be/pxXeNogaiMc

A. Workshop Objectives and Content

The objectives for the meeting were to share key aspects of our upcoming IDP filing and offer an opportunity for stakeholders to engage with our subject-matter experts to both ask questions and offer feedback. The agenda for the IDP Workshop was as follows:

1. Overview of Integrated Distribution Planning in Minnesota.
2. Explain the changing distribution planning landscape and the Distribution business drivers, strategic priorities, our view of the evolution of the interconnection process, our planning process, and how we are planning to implement our new advanced planning tool (LoadSEER).
3. Preview the preliminary Distribution system capital and O&M budgets and trends.
4. Outline the Distributed Energy Resource forecasts and forecasting methodologies.
5. Discuss our current NWA analysis, our takeaways from the NWA stakeholder workshops, and our proposed approach for our 2022 NWA analysis.
6. Summarize our Advanced Grid plans, discuss each of the advanced technologies either in process or planned in the near-term, and outline how we intend to engage with customers, and our product and service roadmap.
7. Discuss our planned 2021 Certification Requests for Distributed Intelligence and the Resilient Minneapolis Project.

8. Preview our phased plans for leveraging the remote operations capabilities of AMI.

B. Engagement Topics and Questions

We encouraged participants to ask questions – and we received a lot of questions and engagement throughout the Workshop. This section summarizes the questions asked in the various subject-matter areas we covered in the Workshop.

1. Planning, Priorities, Budget and Load Forecast Overview, Evolution of Interconnection Process

- Strategic priorities for racial and economic equity for the IDP.
- How you are planning for the future workforce – one that represents the community and has the expertise needed for planning and operating a resilient grid.
- The Company's plans for using smart inverter capabilities.
- Why the Company's growth is forecast flat or tapering when there is so much happening around electrification.
- Whether the Company plans to have a 101 level IDP workshop for community members who want to give feedback about the needs/reliability of their neighborhood grid but will be unfamiliar with IDP terms.
- How the Company coordinates with local governments on infrastructure projects to ensure efficiency and reduce redundancy in terms of road construction.
- Whether LoadSEER uses active distribution line load/voltage monitoring and DER output/curtailment with storage charge/discharge timing as an NWA line activity and smart inverter control. And if not, if there is another tool or control system in development to do this.

2. DER Forecasts

- How the Company factors in local government in-boundary solar capacity goals into its DER forecasts.
- Why Solar Rewards stays flat but net meter and community solar gardens (CSG) grow so much.
- When Solar Rewards ends.
- Does the Company see a change in its lobbying regarding CSGs.

- Please include an explanation as to why there is a slowdown in the CSG forecast.

3. Non-Wires Alternatives Analysis

- Whether demand response includes battery storage or if that just included in NWA.
- Where can individuals find summaries from the NWA workshops 1 and 2 and is there basic background information on NWA for those who missed the workshops and are new to it.
- Is the assumption that all NWAs will be identified by the Company or will the Company issue an RFP for projects from other parties such as solar developers.
- Whether the NWA cost screens (criteria, inputs, results) available to be looked at by the public.
- How the general cost/benefit stacked values compare with the avoided cost values used in the value of solar.
- How the Company differentiates between reliability and resilience for NWA purposes, and what is the Company's definition of the resilience values.
- Why use a 10-year period for NWA – and whether the NWA should be analyzed at its service life.
- How the IPCC's newest research on climate change impacts is or isn't integrated into the NWA cost-benefit analysis over time. How climate risk is considered. Whether the increased severity of impacts increase the value of reducing greenhouse gases.
- How the Company determines which sites/projects go through an NWA evaluation.

4. Advanced Grid Plans

- Whether the FAN communications to a control center is secure.
- Whether the FAN will have line voltage monitors integrated in areas with line voltage issues.
- The Company's plans for IVVO. Why the Company isn't planning to deploy IVVO. Expand on the revenue considerations regarding IVVO.
- Customer cost for a new AMI meter and whether there be a direct charge to customers.

- Whether the AMI implementation materials be in English, Spanish, Hmong, and Somali.

5. Certification Request – Distributed Intelligence

- Whether Distributed Intelligence (DI) is part of the AMI project.
- Whether energy management tracking systems will be an option for commercial customers.
- Whether AMI will be able to share line voltage/power factor data without the DI chip enabled.
- The total cost for DI.
- Whether customers will have a choice on the home AMI meters.
- Whether the Company has preliminary benefit-cost ratio results available for DI.

6. Certification Request – Resilient Minneapolis Project

- Whether the Company anticipates bringing the values of community and social resilience into the IDP proceeding to justify socializing the cost of these projects.
- How this connects with the equity performance metrics proceeding. Whether the Company is considering including those type of disparate impacts of outages within the metrics.
- Whether the Company is offering placement opportunities for the trainees.
- To what extent is the Resilient Minneapolis project a one-off for a docket vs. the first of a broader strategy to embed the needs and inputs of residents (particularly residents experiencing environmental racism/classism) into the plans of the utility.
- Whether the Company views this as something that is part of an obligation under state law/regulatory mandate/direction or a corporate initiative that is more at-will.