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Minneapolis, MN 55401

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November 1, 2023

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2023 INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/M-23-452

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Integrated Distribution Plan (IDP) per the Commission's December 8, 2022 Order in Docket No. E002/M-21-694.

This IDP outlines our distribution strategy and goals; planning process; historical actual and budgeted expenditures; and present and forecasted levels of distributed energy resources. In this IDP, we also discuss our distribution five-year plan and long-term vision.

This year, for the first time, the IDP also includes our Transportation Electrification Plan (Appendix H), in which we present proposals for new electric vehicle-related offerings as well as modifications to our existing pilots and programs.

This IDP complies with all of the filing requirements provided in the above-referenced Order. For additional compliance information, see the Compliance Matrix provided as Attachment B to this filing.

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 Taige Tople at taige.d.tople@xcelenergy.com or me at amber.r.hedlund@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

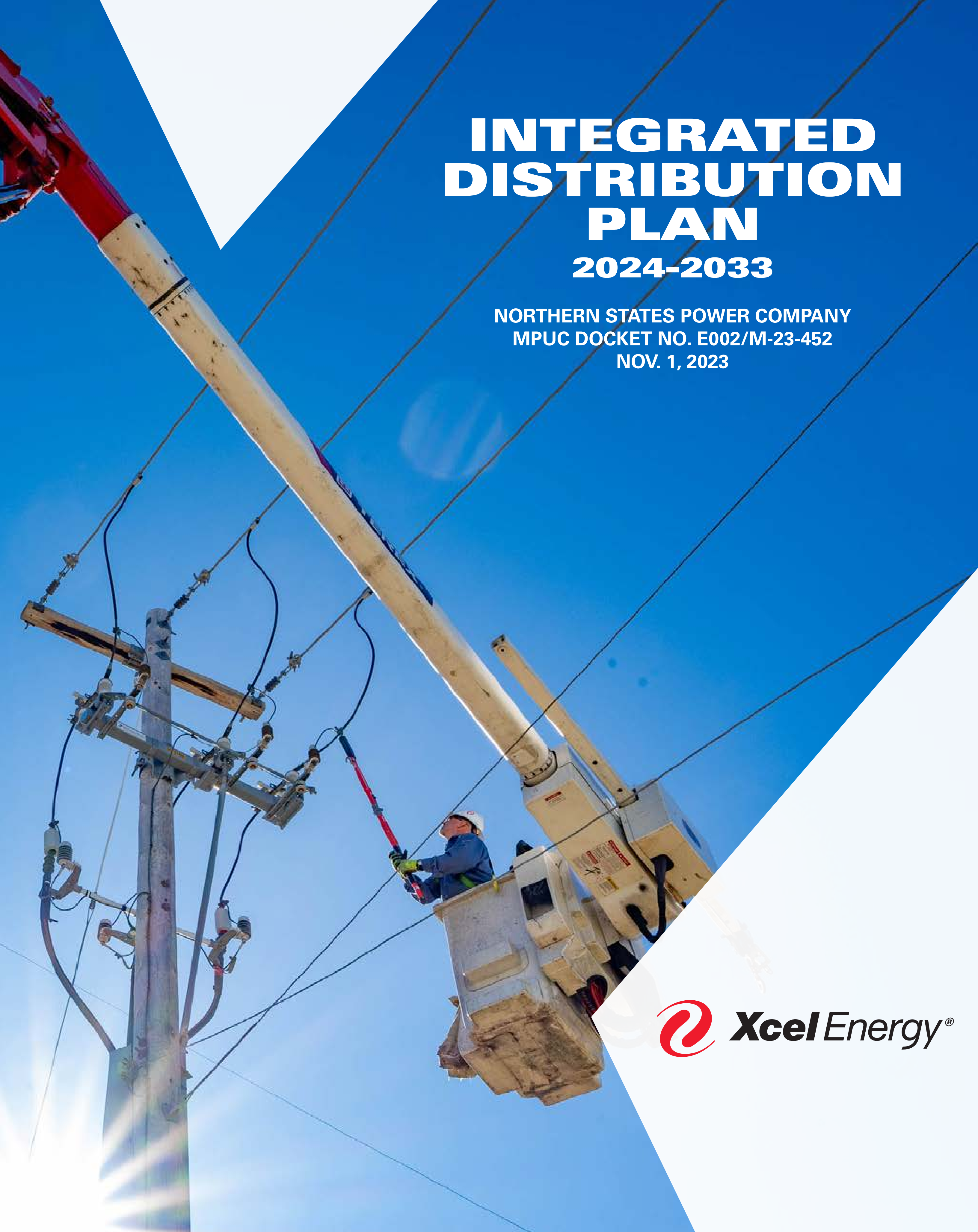
AMBER HEDLUND
MANAGER, REGULATORY PROJECT MANAGEMENT

Enclosures
cc: Service Lists

INTEGRATED DISTRIBUTION PLAN

2024-2033

NORTHERN STATES POWER COMPANY
MPUC DOCKET NO. E002/M-23-452
NOV. 1, 2023



Xcel Energy®

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
ARC	Aggregator of Retail Customers (non-utility)
ARR	Avoided Revenue Requirement
ATB	NREL's Annual Technology Baseline
BCR	Benefit-Cost Ratio
BE	Beneficial Electrification
BEV	Battery Electric Vehicle
BTM	Behind the Meter
BYOC	Bring Your Own Charger
BYOD	Bring Your Own Device
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CEMI	Customers Experiencing Multiple Interruptions
CIP	Conservation Improvement Program
CMO	Customer Minutes Out
CPE	Customer Premise Equipment
CPUC	Colorado Public Utilities Commission
CRS	Customer Resource System
CSA	Customer Service Agreement
CSG	Community Solar Garden
CVR	Conservation Voltage Reduction
DCC	Distribution Control Center
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DF_{PV}	Dependability Factor of PV
DG	Distributed Generation
DG-PV	Photovoltaic Distributed Generation
DI	Distributed Intelligence
DML	Daytime Minimum Load
DOE	U.S. Department of Energy
DR	Demand Response
DRIVE	EPRI's Distribution Resource Integration and Value Estimation tool (for Hosting Capacity Analysis)
DSES	Distributed Solar Energy Standard
DSIP	Distribution System Implementation Plan
DSM	Demand Side Management
DSPx	DOE's Next Generation Distribution System Platform
ECO	Energy Conservation & Optimization

EE	Energy Efficiency
EJ Area	Environmental Justice Area of Concern
EPRI	Electric Power Research Institute
ERT	Estimated Restoration Time
ESB	Enterprise Service Bus
EV	Electric Vehicle
EVAAH	EV Accelerate at Home
EVSE	EV Supply Equipment
EVSI	EV Supply Infrastructure
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FLM	Feeder Load Monitoring
FLP	Fault Location Prediction
FPIP	Feeder Performance Improvement Program
FTM	Front of the Meter
GIS	Geospatial Information System
HAN	Home Area Network
HCA	Hosting Capacity Analysis
HDV	Heavy-Duty Vehicle
HEM	Home Energy Management
ICT	Innovative Clean Technology
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
IT	Information Technology
ITC	Investment Tax Credit
IVVO	Integrated Volt VAr Optimization
LBNL	Lawrence Berkeley National Laboratory
LCR	Local Capacity Resource
LDV	Light-Duty Vehicle
LTC	Load Tap Changers
LTE	Long-Term Evolution
MAIFI	Momentary Average Interruption Frequency Index
MDMS	Meter Data Management System
MDV	Medium-Duty Vehicle
MED	Major Event Day
MISO	Midcontinent Independent System Operator
MNDIP	Minnesota Distributed Energy Resources Interconnection Process
MPUC, PUC, or Commission	Minnesota Public Utilities Commission
N-0	System intact operating condition
N-1	Single contingency operating condition

NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NIST	National Institute of Standards and Technology
NMS	Network Management System
NREL	National Renewable Energy Laboratory
NSPM or Company	Northern States Power Company-Minnesota (Minnesota, North Dakota, and South Dakota operating company)
NSPW	Northern State Power Company-Wisconsin (Wisconsin and Michigan operating company)
NWA	Non-Wire Alternatives
OEM	Original Equipment Manufacturer
PHEV	Plug-In Hybrid Electric Vehicle
PiE	Partners in Energy
PNL	Planned Net Loading
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado (Colorado operating company)
PSIP	Power Supply Improvement Plan
PTMP	Point-to-Multi-Point
PV	Photovoltaic
R&D	Research and Development
RERRA	Relevant Electric Retail Regulatory Authority
RFP	Request for Proposals
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
SES	Solar Energy Standard
SPS	Southwestern Public Service (Texas and New Mexico operating company)
SVC	Static VAr Compensators
TCR	Transmission Cost Recovery (Rider)
TEP	Transportation Electrification Plan
TLG	Transformer Loading Guide
TLY	Typical Load Year
TOU	Time of Use
TPS	Technical Planning Standard
V2G	Vehicle-to-Grid
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.

INTEGRATED DISTRIBUTION PLAN

INTRODUCTION

The electric distribution system is a crucial and highly visible part of the electric grid serving as the electric interface that our customers interact with and use daily. Xcel Energy (the Company) strives to operate our system safely and reliably, while continuing to evolve and transform the system to enable the clean energy transition. 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 robust economic health of Minnesota through affordable and increasingly clean power. Now more than ever, we are in a time that requires deliberate and strategic distribution planning, and we are committed to meeting the exciting challenges inherent in the clean energy transition.

With this Integrated Distribution Plan (IDP), we provide a description of our distribution strategy and plan and how we plan the system to meet our customers' current and future needs in a time of unprecedented load growth. This document is structured in seven sections:

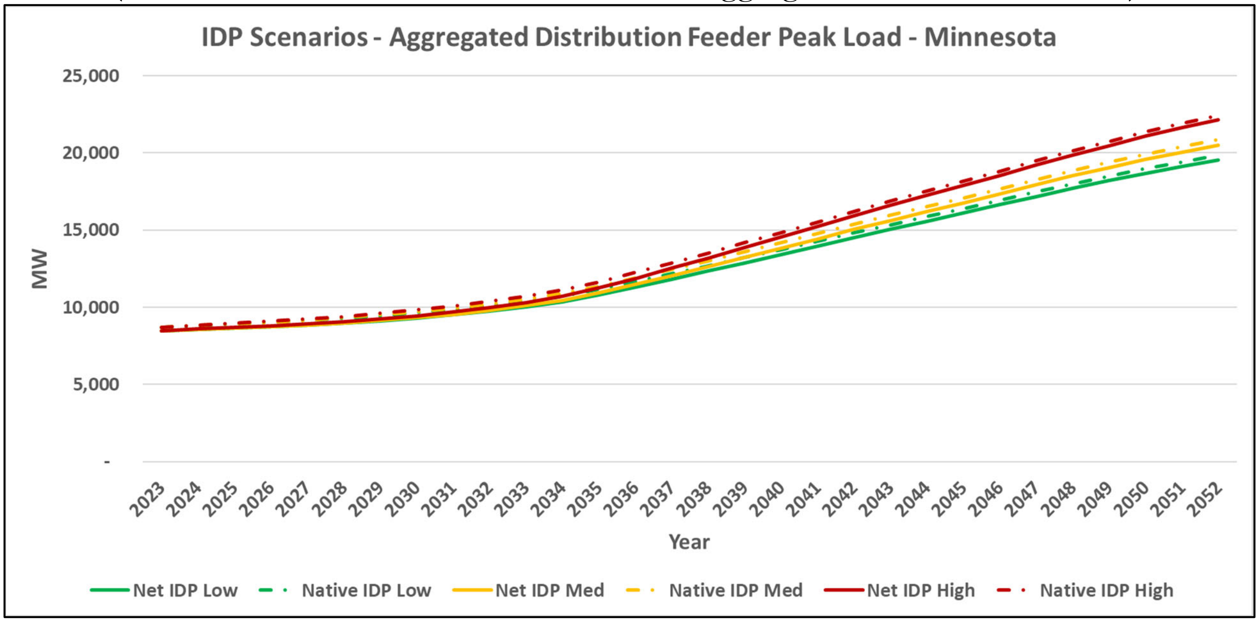
I. Integrated Distribution Plan Background, Requirements and Landscape
II. Overview of Xcel Energy and its Distribution System
III. Distribution Strategy and Plan
IV. Distribution Financial Highlights (Capital and O&M)
V. Financial and Cost Recovery Considerations
VI. DER Snapshot and Forecasts
VII. Action Plan Summary

Importantly, this document is intended to be a high-level overview of the IDP. Below, we provide a table of contents for the appendices in this 2023 IDP filing, where further detail and analysis can be found. The table also includes a note indicating topics that are either new or have changed since our 2021 IDP filing.

Appendix	Topic	
A1	System Planning	Substantially Changed
A2	Standards, Asset Health and Reliability Management	Updated
A3	Distribution Operations	Updated
A4	Distribution System Statistics	Updated
B1	Grid Modernization	Substantially Changed
B2	Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies	Updated
B3	Existing and Potential New Grid Modernization Pilots	Substantially Changed
C	Action Plans	Substantially Changed
D	Distribution Financial Information	Updated
E	Distributed Energy Resources, System Interconnection, and Hosting Capacity	Substantially Changed
F	Non-Wires Alternatives Analysis	Substantially Changed
G	Stakeholder Engagement	Substantially Changed
H	Transportation Electrification Plan	New
I	Distribution System Improvements	New
J	Distributed Intelligence	New

This IDP is the first since Minnesota's landmark 2023 legislative session, which resulted in new and modified laws that have significantly impacted distribution system planning. As highlighted by the recent legislative session, we are facing the monumental challenge of expanding the distribution system to support the increased utilization and demand for electrification of homes, buildings, and transportation. The most influential factor in this IDP is, as shown in Figure 1, we estimate that the feeder peak load of the distribution system will *triple in size* over the next 30 years. This includes new customer loads, distributed generation and the impact of demand response and energy efficiency.

Figure 1: 30-Year Distribution Peak Demand Forecast
(Total Non-Coincident Peak Demand – Aggregated Feeder Peak Load)



In light of this anticipated monumental growth, this IDP is particularly tailored to address and accommodate the evolving policy mandates aimed at decarbonization (e.g. electrification), expanded forms of customer choice (e.g. DER), and the resulting need for significant investment in distribution infrastructure at levels not recently experienced. As we assess our grid, evaluate changing customer needs, and develop our long-term infrastructure plans, four strategic priorities emerge which have influenced our approach to distribution system budgeting and project development.

(1) **Preparing for New and Increased Loads:** We are preparing for a future with increasing loads and DER. Planning for these new expectations begins with evolving our forecasting capabilities to better anticipate these impacts on our system. While we are continuously improving our forecasting process, the forecasts of load and DER growth presented in this IDP already indicate that we will need to make significant infrastructure investments in our distribution system as well as maximize the use of existing infrastructure. Where cost-effective, it will also be important to consider non infrastructure alternatives such as non-wires alternatives and demand response. The combination of these strategies will allow us to meet the evolving expectations of our customers while also remaining focused on prudency and cost-effectiveness.

(2) **Enabling the Clean Energy Transition:** Our energy mix is already over 40% renewable and as the market and our system transitions to deeper levels of

renewable penetration, DER, and electrification, we need more insight and control into the system as well as increased interconnection availability. This IDP discusses our current system and interconnection constraints, while also forecasting the growth of DER and the potential upgrade costs required to interconnect that DER over the next 30 years. This IDP also discusses new technologies that could reduce the need for or cost of some upgrades in the future, such as Distributed Energy Resources Management System (DERMS), smart inverter controls, and flexible interconnections.

(3) **Maintaining and Enhancing Reliability and Resilience:** Our customers expect high quality, uninterrupted power. We will continue to focus on reliability (the day-to-day performance of the grid); as well as resilience (the ability of the grid withstand and recover from significant events). This IDP evaluates the health of our existing system and identifies areas where we need to make investments to continue to serve our customers reliably. These key investments include substation transformers, breakers, and associated gear along with distribution poles, overhead and underground feeders as well as overhead and underground taps. These investments also include maintenance cycles, such as pole inspection and vegetation management.

(4) **Modernizing the Grid:** Grid expectations are changing with customer usage patterns, increased DERs, technical developments, and policy changes. We need to ensure our investments support the evolving needs of the grid and keep up with technology and customers. This IDP discusses not only the grid modernization investments we have made to date, but also those we contemplate for the future, including investments in Distributed Intelligence (DI) and DERMS. The pilots described in this IDP will be instrumental in exploring new use cases for new rate structures and technology, including energy storage and electric vehicles.

This report is designed to provide transparency into our distribution function and planning and complies with all regulatory and legislative requirements. It reflects 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.

Finally, with Order Point 29 of the Commission's July 17, 2023 rate case Order in Docket No. E002/GR-21-630, the Commission requested that the Company propose and discuss with this IDP "ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel Energy to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP." These issues are addressed in Section V below. As discussed therein, the Company does not believe that conducting a cost-benefit analysis (CBA) for all discretionary projects (at the work order level) is feasible or prudent given (a) the sheer volume of projects, (b) the lack of clarity around what would be considered a "discretionary" project, and (c) the divergent priorities/values that stakeholders place on projects that would need to be reduced to a monetary value for purposes of a CBA. Finally, the Company further proposes a modification to the IDP filing requirements. Namely, the Company proposes that the IDP Filing Requirements for Xcel Energy be revised to remove the requirement that financial information be reported in IDP-specific categories. This refinement would allow the Company to report financials in the same budget categories across dockets, facilitating easier comparisons of financial information across proceedings and over time.

We respectfully request that the Commission accept this IDP and approve our proposed modification to the IDP filing requirements.

I. INTEGRATED DISTRIBUTION PLAN BACKGROUND, REQUIREMENTS, AND LANDSCAPE

As an initial backdrop, this IDP is structured and informed by various filing requirements, recent policy developments, and the practical challenges encountered as we operate our distribution system and deliver electric service to our 1.4 million Minnesota customers. An understanding of these background details provided the Company with important context with its distribution planning and development of this IRP and are, therefore, summarized herein.

A. IDP Filing Origins

Minnesota's IDP journey began in earnest in 2015, when 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*. In April 2018, the Commission 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 and, on August 30, 2018, the Commission ordered the Company to file an IDP annually beginning on November 1, 2018. Accordingly, we submitted our first IDP November 1, 2018. Since that time, the IDP filing requirements have evolved and the Company now files a full IDP biannually, with certain financial information and non-wires alternatives (NWA) analysis provided in off-years, starting in 2020.[1]

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:

1. 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,
2. Enable greater customer engagement, empowerment, and options for energy services,
3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies,
4. Ensure optimized utilization of electricity grid assets to minimize total system costs, and
5. Provide the Commission with the information necessary to understand [the Company'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.

See the Commission's Dec. 8, 2022 Order (Docket No. E002/M-21-694).

B. New IDP Filing Requirements

More recently, and as summarized below, the last six months have brought significant changes and new requirements to distribution planning and the IDP filing. In Importantly, each IDP filing is a snapshot in time and we continue to evolve with the changing dynamics of our system, customers, technology, and the market.

New Legislative IDP Filing Requirements

- Forecast distribution system upgrades needed to accommodate distributed generation resulting from the community solar and distributed solar energy

[1] For additional background on the IDP and its origins, evolution, and Commission requirements prior to 2021, see our November 1, 2021 IDP filing in Docket No. E002/M-21-694.

standard statutes, and other customer-sited projects, including storage.

- Evaluate measures that can reduce the need for or cost of distribution system upgrades.
- Discuss alternative methods to allocate costs of distribution system upgrades.

New Regulatory IDP Filing Requirements

- Report on Fault Location Isolation and Service Restoration (FLISR) budget approved in the rate case along with a summary of FLISR's reliability results.
- Propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases.
- Track and report planned and actual spending on reactive and proactive cable replacements.
- Refile the Distributed Intelligence program proposal.
- Assess and explain whether Integrated Volt-Var Optimization (IVVO) is in the public interest.
- Quantify the incremental hosting capacity and beneficial electrification that will be accommodated by planned distribution system investments.
- Discuss how we capture and maximize the benefits from the Inflation Reduction Act (IRA), and how the IRA has impacted planning assumptions.

Attachment B to this IDP provides a summary compliance table of the Commission's various Order Requirements and other filing requirements, identifying the locations in this IDP where we provide the information responsive to each requirement.[2] The various IDP requirements are also stated throughout this IDP.

C. Current IDP Planning Landscape

The environment in which we plan for distribution will continue to evolve. As discussed below, this environment is presently most significantly influenced by (1) legislative policies and (2) supply chain difficulties.

With respect to policies, we expect the technology, policy interests, and customer expectations to continue to inform our strategy in several significant ways in the next five to 30 years.

The essential role that electricity plays in our customer's lives is ever-changing. While the power system is the lifeblood of our economy, we are anticipating that as customers

[2] The latest IDP Requirements for Xcel Energy are included with the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879. Throughout this IDP, references to specific IDP Requirements use the numbering and language from that Order.

continue to electrify additional areas of their lives, such as transportation and space heating, there will be additional service expectations placed on our system. Notably, emergent EV and heating load on our system is expected to quickly grow to overshadow the electric demand seen today. For example, in some cases, an EV charging load can be as much as 1x the load of an average residential customer, and a residential home with electric space heating (Air Source Heat Pumps with resistance backup) can add as much as 4-5x the average load of a residential customer. These are significantly large and stressing loads that are expected to be added to our system at unprecedented rates. Additionally, we have seen the proliferation of DER on our system which presents a unique challenge in how they interface with our system with these asset types acting as both a load and resource on our system. This has the effect of increasing two-way power flow, stressing feeders with higher utilization, and increasing the complexity of distribution system operation. Through continuous improvement and step changes in our planning approach and standards, we are committed to meeting these challenges and maximizing opportunity.

Customer expectations continue to increase, as will their reliance on the electric system to support everyday activities (e.g., EVs). Moreover, the distribution system will continue to add new types of loads and resources – with unique and different profiles compared to historical distribution system operation. Simply put, "normal" distribution planning will need to evolve to capture new opportunities for system reliability and resiliency. In an increasingly power-dependent world, maximizing power quality and minimizing the number and length of power outages experienced by customers is key to customer satisfaction.

Within this broad landscape, the Minnesota state legislature and the Commission have made clear that there must be an increased focus on distribution system planning. As noted above, this IDP addresses many filing requirements that have been added by Commission Order or recent legislative action.

Table 1 provides an overview of the legislation passed in 2023 that we anticipate will have some effect on the distribution system and our planning process.

Table 1: 2023 Electric Distribution-Related Legislative Action Summary

Statute	Description & Relevant Docket	Overview
216B.1641	Community Solar Garden (CSG) program modifications Docket No. E002/M-23-335.	Session Laws significantly modified the CSG program. Most notably for distribution system planning: • CSGs no longer need to be located in the same county or a county contiguous to its subscribers. • Size limitations for new CSGs was increased to 5 MWs from 1 MW. • The program caps annual, new CSG installed capacity at 100 MW for 2024-2026; 80 MW in 2027-2030; and 60 MW in 2031 and beyond.
216C.378	Distributed Energy Resources System Upgrade Program Docket No. E002/M-23-458	Provides funding to Xcel Energy to complete infrastructure investments to enable customer DER interconnections up to 40 kW AC. Includes $10 million in funding over two years through Department of Commerce. Requires plan to be filed with Department of Commerce by November 1, 2023.
216C.379	Energy Storage Incentive Program Docket No. E002/M-23-459	Requires Xcel Energy to develop and operate a grant program for on-site energy storage systems of 50 kWh or less and paired with solar. Requires plan to be filed with Department of Commerce by November 1, 2023.
H.F. 2310 Article 12, Section 75	Queue priority for DER up to 40 kW Docket No. E999/CI-16-521	Requires the Commission to open a proceeding to establish interconnection procedures that give customer-sited DG projects up to 40 kW AC priority over larger projects in the interconnection queue.[3]
216B.1691 subd. 2h	Distributed Solar Energy Standard Docket No. E002,E015,E017/CI-23-403	Requires three percent of the Company's total retail electric sales in Minnesota to be generated from qualifying solar energy generating systems by the end of 2030. To count toward the standard, the solar energy generating system must: (1) have a capacity of ten megawatts or less; (2) be connected to the public utility's distribution system; (3) be located in our Minnesota service territory; and (4) be constructed or procured after August 1, 2023.

This table is not intended to be exhaustive; rather, Table 1 identifies what we see as the 2023 legislation that may have the most influence on the distribution system and planning. While it is still too early to predict all potential costs and impacts of these new and revised laws, it is clear the distribution planning landscape in Minnesota has shifted

[3] On September 1, 2023, the Commission issued a Notice of Comment Period in Docket No. E999/CI-16-521. Proposals are due November 1, 2023.

since our last IDP filing in 2021. In particular, an increased focus on DER and affordability will necessitate what may be difficult prioritization of investments and human resources to ensure we can continue to meet our obligation to serve to all customers – while supporting new and expanded programs and state priorities that impact the distribution system.

In addition to recent policy initiatives that will shape our distribution planning, supply chain issues have affected the economy since the start of the COVID-19 pandemic and these issues continue to impact distribution planning. Although many types of equipment are affected by supply chain challenges, the most significant impact is in transformer supplies. Disruptions in overseas and domestic manufacturing have caused significant delays and shortages of critical materials such as steel and components required in the manufacturing of transformers. Further, labor disruptions have become a factor in supply chain and inflation and other factors have driven costs up at least 50 percent over 2020 averages. We have been working to manage existing transformer inventory and increase supply where possible to minimize service interruptions to customers. We are also taking steps to make our supply chain more redundant and resilient to mitigate the impact of the industry-wide transformer shortage. These steps include:

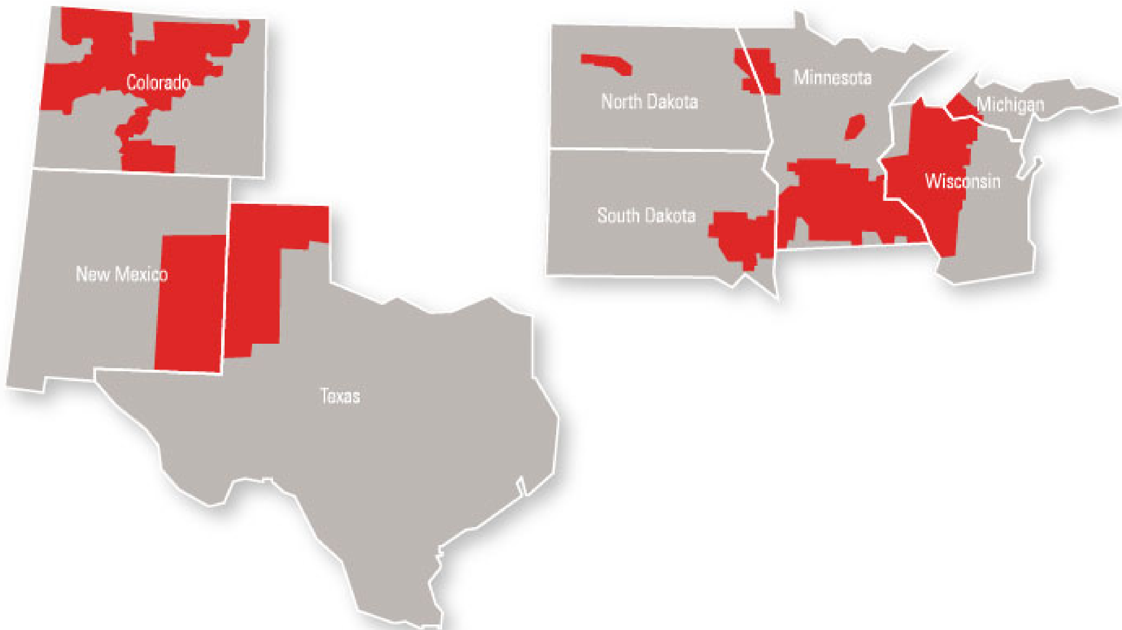
- Increasing our inventory of transformers and other equipment and working with vendors to ensure that they are expanding their own inventories wherever possible.
- Placing long-term purchase orders for new equipment into 2024 and beyond.
- Seeking to diversify our suppliers where possible. While we are focused on domestic equipment sources, we are also seeking additional transformer and conductor suppliers outside the US for the first time. We have entered into new contracts with two manufacturers in South Korea for regular shipments of distribution transformers. Currently, these suppliers offer shorter lead times than the domestic transformer sources.
- Exploring the use of alternate materials, designs, and parts where appropriate.
- Establishing a dedicated market intelligence and business analytics team to evaluate supply chains and plans for critical materials, including transformers, cable and wire, wood poles, and other equipment.
- Expanding our transformer rebuild and refurbishment program to its maximum capacity.
- Increasing spare quantity levels to support planned and emergent projects.
- Leveraging alliance agreements, which can help improve lead times.

Despite these efforts, these supply chain issues are not expected to abate in the near term, which presents a national security challenge requiring a federal response. To that end, we are working with industry partners, the US Department of Energy, transformer manufacturers, and other critical infrastructure partners to encourage federal action on this issue. The federal government could support efforts to improve the availability of labor and use the Defense Production Act to reconfigure other US manufacturing facilities to produce distribution transformers and seek federal funding for expanded production. We continue to communicate with builders and developers about transformer supply for their projects as we navigate ongoing challenges with long lead times for equipment for new projects, which further necessitates important prioritization and thoughtful planning approaches.

II. OVERVIEW OF XCEL ENERGY AND ITS DISTRUBTION SYSTEM

Xcel Energy is a major US 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 3.8 million electricity customers and 2.1 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 – Northern States Power Company – Minnesota (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.

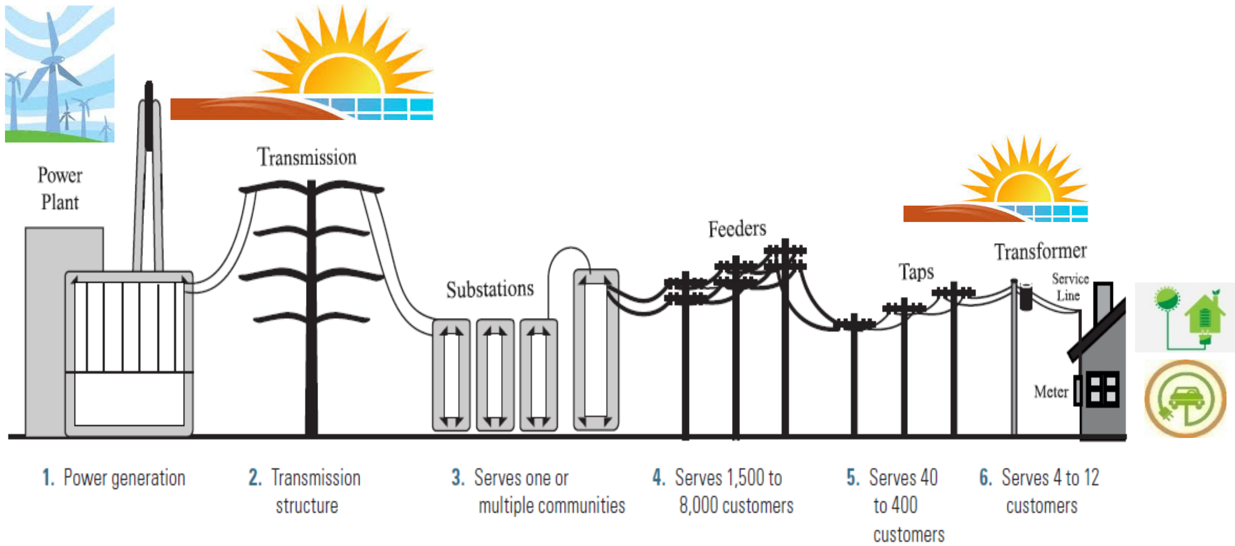
Figure 2: Xcel Energy Service Areas



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 23 percent of electricity sales, with commercial and industrial customers making up most of the remaining 77 percent.

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 from substations to our customers as shown below.

Figure 3: Illustrative Electrical Grid



The NSPM electric distribution system serves approximately 1.5 million customers (approximately 1.4 million in Minnesota) – and is composed of 1,207 Feeders, 250 distribution-level substations, approximately 13,000 circuit miles of overhead conductor, and approximately 10,500 circuit miles of underground cable. This system is managed and operated by the many 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 2022 reliability thresholds for SAIFI, SAIDI, and CAIDI at the second quartile for large utilities.[4]

III. DISTRIBUTION STRATEGY AND PLAN

Within this rapidly shifting planning landscape, the evolution of the Company's distribution strategy and planning process is ongoing.. Our strategy incorporates not only the necessary work to maintain existing infrastructure, but also proactively identifying and investing in the necessary additional infrastructure, capabilities, and workforce needed to prepare for the future. The combination of these two approaches will allow us to facilitate the clean energy transition, maintain and enhance reliability and resilience, and modernize our customers' interactions with the distribution grid.

[4] See the Company's August 16, 2023 filing in our Service Quality Docket No. E002/M-23-73. IEEE stands for Institute of Electrical and Electronics Engineers. SAIFI stands for System Average Interruption Frequency Index. SAIDI stands for System Average Interruption Duration Index. CAIDI stands for Customer Average Interruption Duration Index.

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. In short, our distribution strategy is to:

> *Proactively invest in our distribution system so that capacity is available before our customers need it as well as prepare our system to accommodate increasing penetration of distributed generation resources. We plan to do this by making investments in baseline capacity, improving asset health thereby decreasing reliability risk, and deploying industry leading technology solutions, both hardware and software, to maximize grid value while maintaining affordable rates for customers.*

Characteristics of anticipated load growth require a paradigm shift from the historical ways of planning and operating the grid. In the past, we have generally seen gradual, localized load growth with longer lead times often tied to large construction projects leading to more predictable patterns for required upgrades. The new paradigm involves rapid, system-wide load growth that can be difficult to predict, particularly in light of the planning landscape discussed above. These rapid, concurrent system-wide changes require the industry to re-evaluate our approach to planning and operating the grid. New approaches to grid planning processes are needed to optimize, prioritize and right-size capacity investments. Collaborative customer interaction is critical to our success.

We expect our planning process to evolve rapidly. For example, we are striving to load feeders to approximately 75 percent of maximum capacity, which provides reserve capacity that can be used to interconnect new customers and loads more quickly. This is also expected to provide increased operational capability and the ability to continue serving load under first contingency N-1 conditions. Additionally, we have developed an initial methodology to prudently plan the distribution system using net load, which includes the load-reducing impact of distributed generation. These changes are discussed further in *Appendix A1: System Planning*. We will continue to evolve these processes as necessary, including identifying new ways to appropriately plan proactive infrastructure upgrades to prepare for rapid load and DER growth on the distribution system.

Our near-term investments in our distribution system are focused on achieving four primary objectives: (1) preparing for new and increased loads; (2) enabling the clean energy transition; (3) maintaining and enhancing reliability and resilience; and (4) modernizing the grid. We discuss each of these strategic objectives and our plans to achieve them below.

A. Preparing for New and Increased Loads

Preparing now for a future with increased loads and DER is paramount. To prepare for the next 30 years, improved and proactive system planning and processes – and associated tools – will be required. As noted above, we forecast that the load served by the distribution system will triple over the next 30 years. As described in greater detail in Appendix A1, Appendix D, and Appendix E, this load increase will require build out of substantial new infrastructure as well as new resources (e.g., NWAs and flexible loads) and technologies to improve the utilization of existing infrastructure to accommodate new loads and distributed generation. We are taking a strategic and balanced approach to our system planning that will maintain or enhance levels of service for all customers while enabling future load growth and DER. Increasing our investment in the system is necessary, and keeping bills low remains a priority for the Company. The demands being placed on the system require significant new infrastructure investment as well as expansion of existing infrastructure. The Company's ability to recover those investments in cost recovery proceedings is vital not only to providing basic utility service but also to comply with new laws and Commission requirements. As always, we will continue to weigh and prioritize competing objectives to manage costs.

We have included a placeholder estimate in the five-year budget for proactive system upgrades to increase DER hosting capacity. We have heard from the state legislature, the Commission, and stakeholders that increased hosting capacity is a growing priority for the State of Minnesota. While we have not yet identified specific uses for this funding we look forward to stakeholder and Commission feedback on how we should prioritize these funds. We provide additional analysis on interconnections in *Appendix I: Distribution System Upgrades*.

In addition, we are building new capabilities and ways of working that will be crucial to the long-term health of the system. Just as the grid is evolving, so must the personnel who engineer, design, operate, and maintain it. As initiatives continue to grow, such as DER interconnections, we need to add additional resources to existing teams. As load growth increases, DER strategies change and emerge, technologies continue to evolve, our personnel must do the same. We anticipate our resources to grow as our load curve grows, however, at an earlier and proactive pace. We need more engineering employees to design the uptick in capital projects. Along with our existing skillsets, we will ramp up our resources with data analytics, project management and emerging technologies.

Finally, the Company has begun the implementation of LoadSEER -- our forecasting and analytics tool that is foundational for long-term planning. LoadSEER evolves our forecasting capabilities to better anticipate these impacts on our system With

LoadSEER (see Appendix A1), we can begin the transition to considering the impacts of DER integration, EV adoption, beneficial electrification, and performing scenario analyses for the evolving grid. This IDP represents an exciting milestone in that we are presenting load and DER scenario forecasts from LoadSEER for the first time. We see improved forecasting as the beginning to improving planning capabilities to build and maintain a system that meets all of our customers' future needs.

B. Enabling the Clean Energy Transition

The electric sector is already moving quickly to decarbonize power generation and is uniquely positioned not only to lead the decarbonization of the sector itself but also to contribute significantly to a net-zero economy. Our Upper Midwest Xcel Energy System is already over 40% renewables and 70% carbon free—and with Minnesota's new legislation we will "generate[s] or procure[s] an amount of electricity from carbon-free energy technologies that is equivalent" to 100% of our "total retail electric sales to retail customers in Minnesota." *See* Minn. Stat. § 216B.1691, subd. 2g. Supply resources are becoming less carbon-intensive and more diverse; decentralization of generation is accelerating – driven by advances in technology and new business models, as well as new and expanded policy priorities focused on increasing distributed solar and other DER as well as broad electrification of transportation and other end-uses.

Indeed, federal incentives for decarbonization in both utility generation as well as residential and DER investments are driving an enormous increase in the renewable market. The Inflation Reduction Act (IRA) – the largest climate investment ever by the US government – is expected to more than triple US clean energy production in less than 10 years, which would result in about 40% of the country's energy coming from renewable sources such as wind, solar and energy storage by 2030.

As explained in *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity.*, we are beginning to consider more proactive and tailored investments that enable the clean energy transition, including by supporting the interconnection of generating DER like rooftop solar to the system. In addition, the Company has been making significant efforts to encourage greater transportation electrification in Minnesota. The Company has made efforts to educate and inform the public of the benefits that EVs can bring and developed programs and pilots to address the significant barriers that can prevent adoption. We have seen significant growth in our residential EV efforts and participation in our fleet and public charging pilots are increasing as well. As Appendix H to this IDP filing, we are also submitting our 2023 Transportation Electrification Plan (TEP). In our TEP, we are including several new proposals. These proposals include a new electric school bus demonstration, home wiring rebates, an expansion of our Residential EV Subscription Service Pilot into a permanent offering, and additional funding for our fleet and public charging pilots and EV Advisory Services. We believe these proposals will help us continue to grow our efforts in the EV space and will help us develop greater learnings that can lead future transportation electrification efforts.

C. Maintaining and Enhancing Reliability and Resilience

We strive to provide our customers with quality, uninterrupted power. Reliability and resilience are often overlapping, but different concepts that can require different or complementary grid tools and investments. Reliability improvement opportunities focus on the day-to-day performance of the grid by reducing both the number and duration of outage events on the system. Resilience, on the other hand, focuses on improving the distribution system's ability to withstand, endure and recover from significant events that can create widespread outages and result in long-duration restoration times.

Climate change increases the volume and intensity of storms. It also creates more extreme temperatures.[5] Increased system resilience will be a crucial component of maintaining day-to-day reliability. To that end, we regularly evaluate the overall health of our system on an ongoing basis and make investments where needed to reinforce our system. This evaluation 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 implement replacement and maintenance work plans to both support our customers' needs for reliable service today, and to lay the groundwork for the grid of tomorrow. While we have been making ongoing investments to maintain the reliability of the system by replacing assets on an as-needed basis, we will increase the level of these investments to address the growing number of assets that have reached or are approaching their estimated service life. The Asset Health section of Appendix A2 details the asset investment needs and programs employed to address them. Without these needed asset replacements, the system will be at greater risk of outage events and slower restoration due to equipment failures. This equipment remains the backbone of our operations and we will need these assets to operate smoothly so we can see the efficiency gains expected from our grid modernization investments. Our approach to capital investments needs to balance a variety of considerations including risk, cost, service, and customer demands.

At the same time, both reliability and resiliency are dependent on system security – both physical and cyber (*see Appendix B2: Customer, Operational, and Planning Data Management,*

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[5] *See, e.g.,* https://www.epa.gov/sites/default/files/2016-07/documents/midwest_fact_sheet.pdf; https://www.usgs.gov/faqs/what-are-long-term-effects-climate-change; https://www.un.org/sites/un2.un.org/files/fastfacts_temperature_rise.pdf.

Security, and Information Access Plans and Policies). 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.

Finally, we will continue to implement physical security measures to ensure the safety of our assets (see Appendix B2). We have focused strategic physical security efforts on assets based on their criticality to the stability of the electric grid. Recent physical security events throughout the nation have highlighted the need to address the security of assets beyond the traditional bulk electric system substations. The Company is currently working to expand physical security efforts and is evaluating substation facilities to not only address their criticality to the stability of the electric grid, but their importance to our customers and communities.

D. Modernizing the Grid

The fourth area of focus for distribution is on the implementation of a variety of grid modernization investments. We have implemented foundational 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 are now modernizing the grid in an increasingly impactful way in response to the changing landscape of customer usage patterns, policies, and technical developments. These investments include:

- An Advanced Distribution Management System (ADMS) that provides grid operators important and necessary visibility and control of increasingly complex distribution grid operations,
- Advanced Metering Infrastructure (AMI) that provides customers with detailed usage information to understand and modify their usage to save energy and money – and, foundational capabilities for the Company to improve its operations, lower costs, and more efficiently implement advanced rates and load flexibility programs,[6]

[6] Since our last IDP filing, we have begun installing AMI meters in Minnesota, and have installed more than 500,000 AMI meters so far.

- A Field Area Network (FAN), which brings value to customers by facilitating two-way communications between AMI meters and other smart devices on the distribution grid and the Company's back office systems, and
- Fault Location, Isolation, and Service Restoration (FLISR), which will significantly improve reliability for customers by automating actions on the grid to isolate faults and providing insights to operators that improve outage response efficiency.

We are also moving forward with Distributed Intelligence (DI), leveraging the on-meter computing capabilities of AMI meters. The analytics made possible through DI can provide additional insights to help customers make more informed decisions about their energy usage, increase the ability to connect customers to demand-side management programs, and increase the efficacy of time-differentiated rates. In addition, DI allows the Company to create new, innovative demand side management and demand response offerings. As we take an enterprise-wide approach to our DI plans, Minnesota customers will be able to access and benefit from new apps and tools that become available. We discuss DI further in *Appendix J: Distributed Intelligence*.

Future grid modernization investments will be necessary to integrate more DERs, keep pace with load growth, and ensure efficient and sound operations in an increasingly complex environment. We envision a highly integrated technology environment playing a key role in overcoming challenges such as fluctuations in the grid's frequency and voltage, reduced inertia, and bi-directional power flows. An integrated environment will allow operators to further collaborate to maintain safety and reliability of grid operations through evolving conditions. The deployment of Distributed Energy Resources Management System (DERMS) is an emerging approach to connect and manage DER on the utility system. As penetration levels of DER increase, there is an increasing need to have more visibility and active management and coordination with DER to maintain a secure, reliable, and resilient distribution system. Currently, we are examining DERMS capabilities in the market and will explore vendor capabilities in more detail through 2024. See *Appendix B1: Grid Modernization* for further detail on DERMS.

We have continued to refine our non-wires alternatives (NWA) analysis. In this IDP, our analysis shows that the three projects evaluated in the full stacked values analysis have the potential to be feasible, cost-effective NWAs. Stacked values analysis considers a broader set of costs and benefits in NWA's, in alignment with the National Standards Practice Manual. While this analysis is only the first step in evaluating potential projects, we intend to continue examining NWA solutions and – if any of the projects remain potentially viable and cost-effective, we would then determine next steps in our IDP Annual Update filing in 2024.

With these initiatives, the Company will be able 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 We discuss our grid modernization plans in *Appendix B1: Grid Modernization*, *Appendix B2: Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies*, and *Appendix B3: Existing and Potential New Grid Modernization Pilots*. Our NWA analysis is discussed in *Appendix F: Non-Wires Alternatives*.

IV. 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 Xcel Energy operating utility company, including NSPM. This forecast includes a budget for both Capital and O&M spend. Historically, the 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.

Preparing the distribution system for the future requires a fundamental and proactive shift in the planning and budgeting framework which has been able to meet the needs of our customers over the last century. Now, our budget framework incorporates not only the necessary work to maintain existing infrastructure, but also the investments needed in new and expanded infrastructure, technology, and workforce to prepare for the future and achieve the strategic outcomes of enabling the clean energy transition, maintaining and enhancing reliability and resilience, and modernizing our customers' interactions with the distribution grid. 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.

Each year when a five-year budget is created and approved, the first-year budget is essentially "locked in." However, budgets for the subsequent two to five years are reevaluated in the next budgeting cycle and will necessarily change in response to new developments and changing policy priorities, and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period. Distribution budgets must maintain flexibility to adjust to emergent circumstances and weather. The Company's Capital Budget Forecast and O&M Budget forecast are summarized below.

A. Capital Budget Forecast

While the Capital Budget Forecast details are provided at Appendix D. Table 2 below provides an overview of our 5-year capital budget in the IDP categories, reflecting investments aligning with our primary strategic objectives: (1) preparing for the future; (2) enabling the clean energy transition; (3) maintaining and enhancing reliability and resilience; and (4) modernizing the grid.

Table 2: Distribution Capital Expenditures Budget – State of Minnesota – Electric 2023-2027 (Millions)

	Bridge Year	Budget					Budget Avg
IDP Category	2023	2024	2025	2026	2027	2028	2024-2028
Age-Related Replacements and Asset Renewal	$136.9	$179.4	$199.6	$231.2	$252.7	$272.4	$227.1
New Customer Projects and New Revenue	$50.1	$44.9	$47.6	$49.2	$51.1	$53.5	$49.3
System Expansion or Upgrades for Capacity	$35.8	$61.8	$93.2	$159.0	$193.3	$227.1	$146.9
Projects related to Local (or other) Government-Requirements	$29.2	$37.2	$39.6	$40.6	$41.6	$43.3	$40.4
System Expansion or Upgrades for Reliability and Power Quality	$40.9	$38.7	$55.4	$76.4	$201.2	$328.0	$139.9
Other	$70.8	$74.1	$55.1	$54.8	$56.4	$63.4	$60.7
Metering	$5.3	$4.1	$4.4	$4.7	$4.6	$4.5	$4.5
Grid Modernization and Pilot Projects	$115.4	$111.3	$56.3	$40.9	$33.5	$10.8	$50.6
Non-Investment	($2.1)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)
Electric Vehicle Programs	$9.3	$8.9	$1.4	$18.4	$36.9	$71.8	$27.5
TOTAL	$491.7	$556.5	$548.5	$671.2	$867.2	$1,070.7	$742.8

Of note, in the five-year budget, starting in 2025 we have included a placeholder estimate, totaling $190 million, for proactive system upgrades to increase DER hosting capacity. We have heard from the state legislature, the Commission, and stakeholders that increased hosting capacity is a growing priority for the State of Minnesota. That said, we have not yet identified specific uses for this funding – it is intended solely as a placeholder at this time, subject to change based on stakeholder and Commission feedback and additional analysis.

In the near term, our ability to accommodate electrification will require investments in areas where the existing primary distribution system capacity may be exceeded. Through the Grid Reinforcements Program, proactive planning and installation of substations and feeders, particularly in congested metropolitan areas, can help enable electrification. Changing climate creates new and greater reliability and resiliency risks to our distribution system – a modernized grid includes investments to mitigate such risks. Upgrading of existing overhead lines to current construction standards for increased system hardening can improve resilience and reliability. Finally, our grid modernization projects – AMI, FAN, ADMS, and FLISR implementations – are underway and will be largely complete within the five-year budget period.

B. O&M Budget and Forecast

The distribution O&M budget is 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, 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 the fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system.

While Appendix D details our 5-year O&M budget for the distribution business unit, Table 3 below provides an overview of the same.

Table 3: Distribution O&M Expenditures Budget – NSPM Electric 2023 – 2028 (Millions)

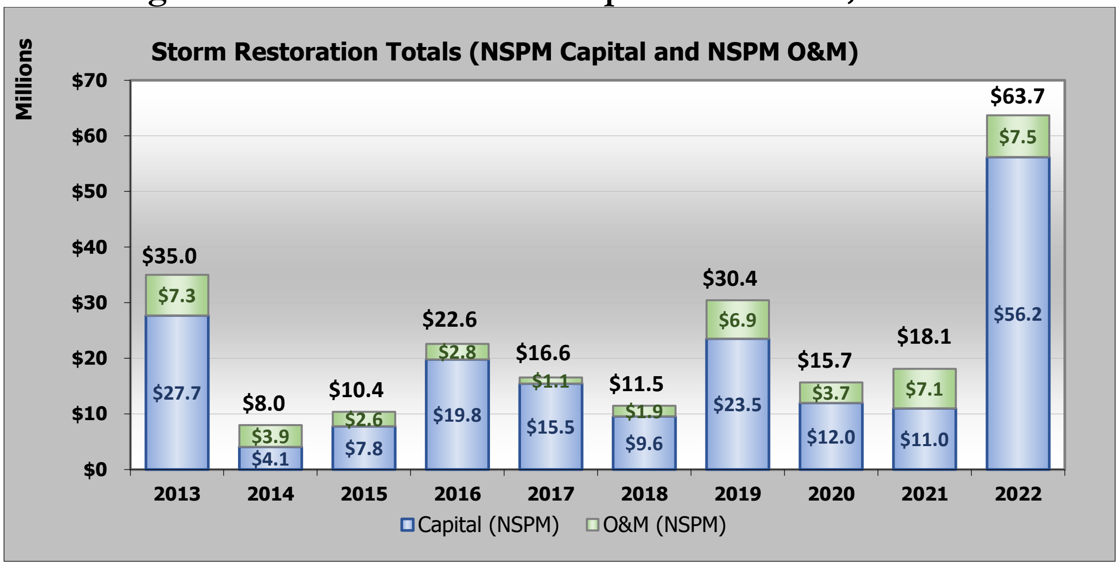
	Bridge	Budget					Budget Avg
Expenditure Category	2023	2024	2025	2026	2027	2028	2024-2028
Labor	$47.8	$45.4	$47.0	$48.6	$50.2	$52.0	$48.6
Cont. Outside Vendor/Contract Labor	$20.1	$17.2	$20.4	$24.5	$22.8	$22.4	$21.5
Vegetation Management	$27.8	$38.3	$37.8	$39.0	$39.9	$42.8	$39.6
Damage Prevention Locates	$12.7	$13.8	$14.3	$18.0	$18.7	$19.3	$16.8
Grid Modernization Projects	$1.3	$2.6	$2.6	$1.7	$1.4	$1.5	$2.0
Other (Materials, Transp, First Set Credits)	$0.3	$10.8	$16.0	$17.4	$18.7	$19.0	$16.4
TOTAL	**$110.0**	**$128.1**	**$138.1**	**$149.2**	**$151.7**	**$157.0**	**$144.8**

O&M expenditures associated with grid modernization and EV programs are presented separately as holistic initiatives; Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the distribution five-year budget include contract labor, for which new higher contract rates took effect over the past two years; as the current contract with our Damage Prevention vendors expires at the end of 2025 and a new contract will need to be implemented starting in 2026, we anticipate another increase due to rising labor rates.

Finally, we emphasize that 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. Notably, Figure 4 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 4: Storm Restoration Capital and O&M, 2013-2022



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.

V. FINANCIAL AND COST RECOVERY CONSIDERATIONS

Order Point 29 of the Commission's July 17, 2023 rate case Order in Docket No. E002/GR-21-630 states:

> *In its next Integrate[d] Distribution Plan (IDP), Xcel must propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to:*
>
> a. *The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget;*
> b. *The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP.*

As an initial matter, the Company believes that the current IDP process provides the needed flexibility for ongoing evolution and refinement, and we appreciate the opportunity to comment on the continued evolution of the IDP process. Generally speaking, the Company believes that the current IDP requirements provide the proper process for the Company to convey the details around its distribution planning. With that said, the Company discusses below (a) the feasibility of cost-benefit analyses (CBA) for discretionary portions of the distribution budget, (b) decisions needed from the Commission on this IDP (none at this time), and (c) a proposed modification to the IDP financial categorization structure for purposes of reporting budgets.

A. Cost-Benefit Analysis Feasibility

Order Point 29 of the Commission's electric rate case Order requires discussion of the "feasibility of conducting cost-benefit analyses [CBAs] for discretionary portions of the distribution budget".

As an initial matter, there is no single universally accepted method of performing a cost benefit analysis. However, every process has some variation of the following five steps:

1. Identify Project Scope
2. Determine Costs
3. Determine Benefits
4. Compute Analysis Calculations
5. Make Recommendation and Implement

Based on this definition, the Company conducts CBAs for a variety of projects in the distribution budget. For example, the Company conducts a robust CBA/risk analysis for capacity projects, as discussed in *Appendix A1: System Planning* and *Attachment D: Risk Scoring Methodology*. This risk scoring methodology helps the Company prioritize capacity projects based on the reliability and financial benefits of the projects compared to the costs. While we have called it a risk analysis, it is a CBA. Similarly, for some capacity projects that we have prioritized in the five-year budget based on risk analysis, we conduct a NWA analysis as discussed in *Appendix F: Non-Wires Alternatives*. Again, although we have not historically referred to these analyses as CBAs, they serve the same function.

Given the magnitude of investment indicated by our forecasts of load and DER in this DSP, however, it is not efficient to conduct a CBA for all discretionary work, and we are concerned that this will impede developing the necessary investments to meet our customer's needs. First, the volume of projects in the distribution five-year budget makes CBAs for each project impracticable and costly. There is a cost to these analyses, and customers ultimately pay for those prudently incurred costs It is important that we not only ensure thoughtful prioritization of our distribution system investments appropriately, but that we, consistent with regulatory requirements, thoughtfully strive to maximize benefits and minimize costs to customers. Moreover, we are concerned that there is not yet sufficient stakeholder consensus on which specific projects are indeed "discretionary" to be able to narrow the list of those projects that could be subjected to a CBA. Finally, a CBA requires project benefits to be identifiable and capable of reduction to a monetary value, and we understand that stakeholders have varying priorities for distribution system investments, which could lead to disagreement on CBA methodologies and assumptions, which could in turn delay important projects.

All that said, we do conduct, and share publicly, CBAs for all the project categories where such a CBA is reasonably feasible and useful. Also, we believe strategically applying CBAs to program level investments would be valuable and will work towards evaluating and developing an approach to do so.

B. Decisions Needed in the IDP For Guidance on Future Rate Case Recovery

Order Point 29 of the Commission's electric rate case Order requires discussion of the "decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP."

At the outset, we note there are no decisions being requested of the Commission at this time. However, the Company notes it welcomes guidance and further discussion on interconnection costs.

With regard to the recent rate case, the Company does not believe that the outcome there – in which certain of the Company's distribution system investments were not approved – is necessarily indicative of a foundational issue with either the rate case process or the IDP process. Indeed, the Company's recently concluded electric rate case is the first completed electric rate case since our first full IDP filing in 2018 as we withdrew our filed electric rate cases in 2019 and 2020. That said, there may be small process adjustments that could be helpful to mitigate certain challenges inherent in the fact that rate cases and IDPs are two separate proceedings with separate scopes and purposes.

The IDP presents a long-term plan and vision for the distribution grid, and a five-year year action plan that aligns with our budget forecast. We file a comprehensive IDP every other year, with certain baseline financial information (including an updated five-year budget forecast) and non-wires alternatives analysis provided annually. By contrast, a rate case requests cost recovery of near-term investments – most recently for the years 2022-2024 – and includes information inherent in the ratemaking process like cost of service, capital additions, and revenue requirements, which are not reflected in the IDP. The timing of rate case filings is determined based on internal analyses of our financial position and other factors; there is typically no predetermined or set schedule for rate case filings.

For distribution, we revisit our five-year budget each year, and the outer years of the five-year forecast are particularly subject to change as we gain more information on system needs. Maintaining this flexibility in the budget (and in actual spending) is critical because it recognizes the dynamic nature of the distribution system and the practical realities of maintaining it. For example, as noted above, the number and strength of storms varies year to year, which is reflected in the variation in actual year to year spending on storm restoration. For these reasons, the five-year budget we present in the IDP will not be identical to the costs for which we seek recovery in a past or future rate case.

We also provide a longer term 10-year vision in the IDP, consistent with the filing requirements. While we may know directionally where we want to go with our investments, we do not typically have the type of information or budget details that would enable the Commission or stakeholders to make a public interest determination on a specific investment or plan[7] – which is consistent with the Commission's planning objectives for the IDP, which state in part:

> *Commission review of distribution system plans is not meant to preclude flexibility or Xcel to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.*

We believe the IDP process is a useful gauge of Commission and stakeholder priorities, and we consider that feedback in our overall strategy as it evolves. To the extent the Commission has policy goals that are not reflected in our IDP, it would be helpful if the Commission could indicate those policy goals explicitly in its IDP Orders.

[7] A request for certification is an exception. Minn. Stat. § 216B.2425 subd. 3(b) as added by 2023 Session Laws states: "The commission may certify a project […] only if the commission finds the proposed project is in the public interest."

C. Proposed Modifications to IDP Filing Requirements

We appreciate the opportunity to comment on potential financial reporting issues with the IDP filing. The Company proposes IDP Filing Requirements for Xcel Energy be updated to remove the requirement that financial information be reported in IDP-specific categories.

The Commission's IDP Requirements for Xcel Energy require financial data to be reported in IDP-specific financial categories that do not perfectly align with our internal budget categories. We have heard from stakeholders that this can create confusion when examining budgets across dockets and years. And as we discuss further in Appendix D, aligning our internal budgets with the IDP-specific categories is a manual process for capital budgets. For O&M expenses, the nature of O&M budgets does not lend itself to such a manual process, but we have been able to create a partial "functional" view of both historical actuals and five-year budgeted amounts. This manual process creates risk of errors, limits the ability of parties and the Commission to compare financial information across dockets, and ultimately distracts from the core Planning Objectives.

For these reasons, in the spirit of finding ways for the "IDP process to inform financial and cost recovery issues in rate cases" as required by Commission Order, we propose that the IDP Filing Requirements for Xcel Energy be revised to remove the requirement that financial information be reported in IDP-specific categories. This refinement would allow the Company to report financials in the same budget categories across dockets, facilitating easier comparisons of financial information across proceedings and over time – including IDPs and rate cases – and vintages, and eliminate the significant manual work required to re-categorize our budget forecasts. This approach is also consistent with the new TEP requirements within the IDP Requirements, which require future spending on transportation electrification initiatives to be broken down across the sections of Xcel Energy's budget, rather than IDP/TEP-specific categories.[8] We note that cost recovery proceedings present capital additions and revenue requirements, whereas the IDP reports capital expenditures. Perfect alignment between filings will not be possible; cost recovery filings represent the most accurate and relevant cost information.

Specifically, we propose the following revisions to the IDP Requirements:

Requirement 3.A.26:

[8] See IDP Requirement 3.F.10-11.

Historical distribution system spending for the past 5-years~~, in each category:~~. Information should be reflected in categories consistent with the Company's cost recovery proceedings

- ~~*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*~~
- ~~*i. Electric Vehicle Programs*~~
  - ~~*1) Capital Costs*~~
  - ~~*2) O&M Costs*~~
  - ~~*3) Marketing and Communications*~~
  - ~~*4) Other (provide explanation of what is in "other")*~~

~~*The Company may provide 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*~~
- ~~*e. Grid Modernization*~~

For each category, provide a description of what items and investments are included.

Requirement 3.A.28:

Projected distribution system spending for 5-years into the future ~~for the categories listed above~~ in categories consistent with the Company's cost recovery proceedings.~~, itemizing any non-traditional distribution projects~~

Requirement 3.A.29:

Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. ~~Driver categories should include:~~

- ~~*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*~~
~~*i. Electric Vehicle Programs*~~
~~*1) Capital Costs*~~
~~*2) O&M Costs*~~
~~*3) Marketing and Communications*~~
~~*4) Other (provide explanation of what is in "other")*~~

Projects should be reflected in categories consistent with the Company's cost recovery proceedings.

We note that we are not proposing any modifications to Requirements 3.F.10 or 3.F.11, which require more specific historical spending and budget information for transportation electrification initiatives. In other words, information provided in response to Requirements 3.F.10 and 3.F.11 includes the information currently required by Requirements 3.A.27.i and 3.A.29.i.

VI. 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 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 vehicles, demand side management, and energy efficiency.[9]

The Company's 2024-2026 ECO Triennial Plan was submitted to the Department of Commerce for approval on June 29, 2023.[10] This Triennial Plan continues the Company's long-standing commitment to energy efficiency. The programming and proposals detailed in this Plan build on the Company's established record of successful energy efficiency and demand response programming. In addition, they represent an exciting new chapter in utility-delivered programming in Minnesota, enabled by the landmark Energy Conservation and Optimization Act of 2021 (ECO Act). In combination, the various components of this ambitious Plan will achieve energy savings

[9] IDP Requirement 3.
[10] *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.

well above the minimum savings targets established in Minnesota Statutes and generate over $1.7 billion in net benefits. [11]

We have one of the largest community solar gardens program in the country, with 864 MW from 463 projects online, and nearly 200 MW of non-CSG distributed solar online.[12] Tables 4 and 5 below summarize current levels of distribution-interconnected DER and how much is in the queue.

Finally, as noted above, the Company is making significant investments in EV-related programs intended to encourage greater adoption of electrified transportation options.

Table 4: Distribution-Connected Distributed Energy Resources – State of Minnesota

(As of March 2023)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	162	10,283	93	3,939
RDF Projects	35	25	1	1
Wind	9	58	<1	5
Storage/Batteries[13]	<1	25	<1	48

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	864	463	304	330
Grid Scale (Aurora)	100	13	0	0

[11] Net benefits based on the Minnesota Test, adopted as the primary test for cost-effectiveness. See Decision, In the Matter of 2024-2026 Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, Docket No. E, G999/CIP-23-46, March 31, 2023. (Further referred to as 2023 Cost-Effectiveness Decision).

[12] As of March 2023.

[13] 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.

Table 5: Minnesota Distributed Energy Resources – Demand Side Management and Electric Vehicles

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency*	2,433	N/A	N/A	N/A
Demand Response	820	421,000	N/A	N/A
Electric Vehicles	N/A	34,532[14]	N/A	N/A

*Cumulative since 2005.

This IDP represents the first time we have conducted our DER forecast scenarios using LoadSEER. LoadSEER is a spatial load forecasting tool that is used by electric distribution system planners to predict how much power must be delivered, where on the grid the power is needed, and when it must be supplied. It integrates geospatial data, system and customer level data, historical and forecasted weather patterns, as well as distribution load flow application data to produce a forecast. The full results are provided in Appendix A1.

In Figure 5 below, we highlight the incremental front-of-the-meter (FTM) solar forecast results, showing significant increase in solar through 2029 as we add projects to our system in compliance with the new Distributed Solar Energy Standard, which requires three percent of the Company's total retail electric sales in Minnesota to be generated from qualifying solar energy generating systems by the end of 2030.

[14] We do not have information that ties our customer accounts to EV users outside of our customer programs. We estimate that there are approximately 34,532 EVs on the road in our service territory. See Appendix 1 for further information.

Figure 5: Incremental FTM Solar PV Growth Allocated in LoadSEER

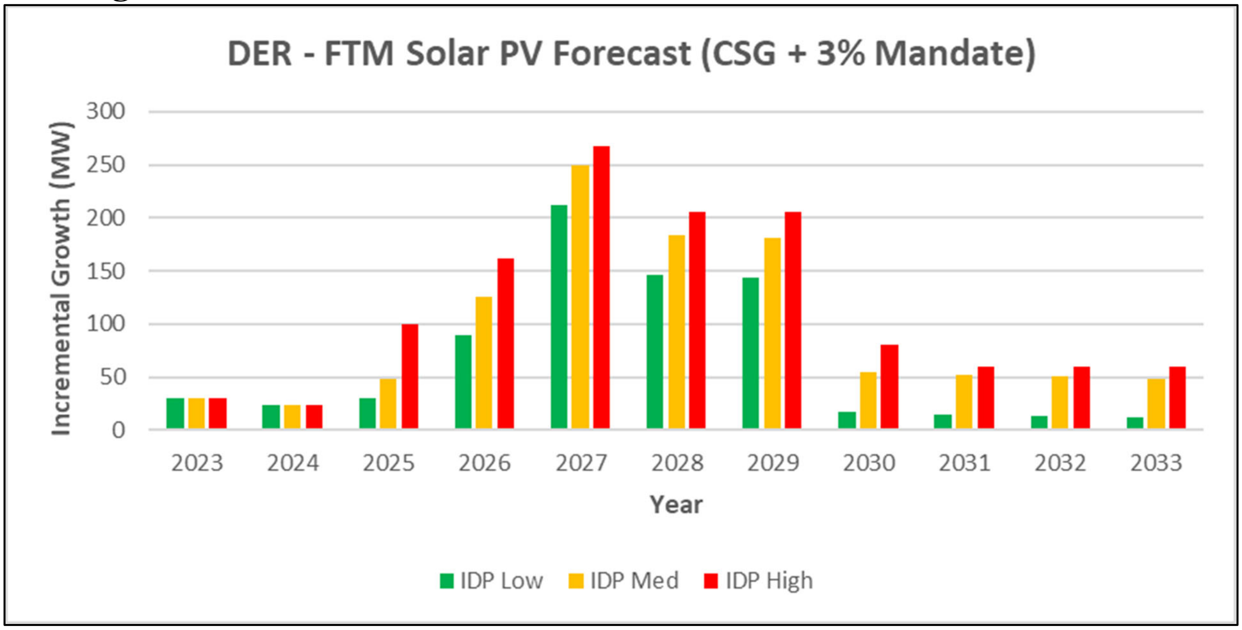
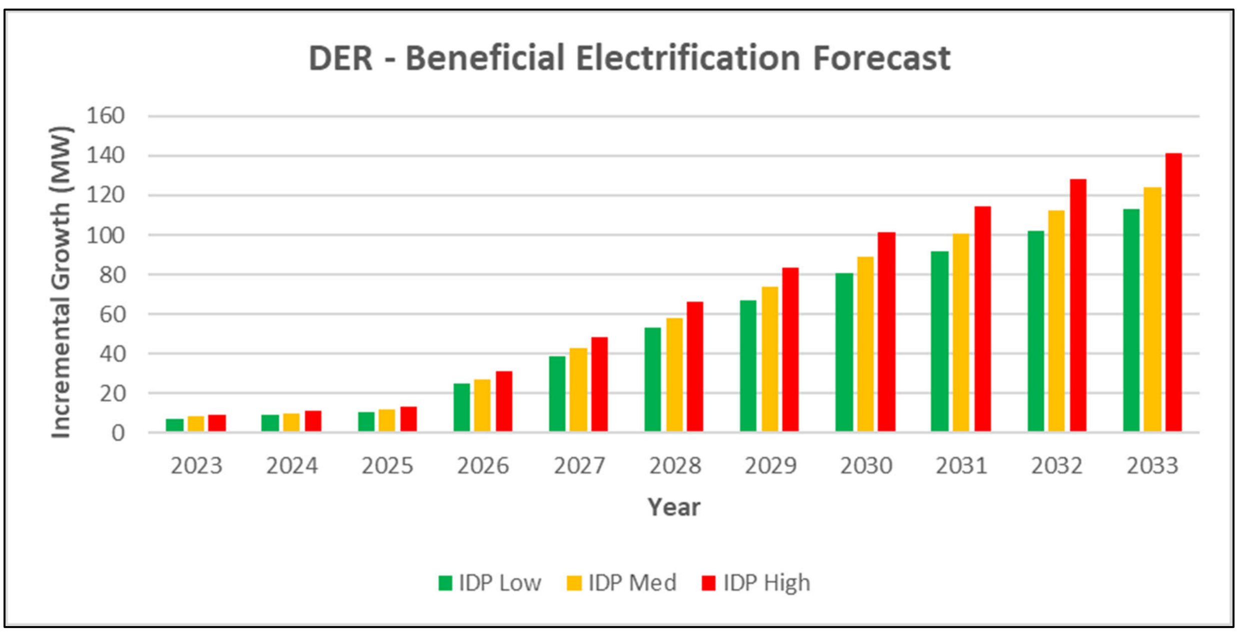


Figure 6 shows the beneficial electrification forecast from our LoadSEER scenario analysis. Although the beneficial electrification forecast for Minnesota is in its nascent stage, currently representing residential water heat and residential space heat, our analysis shows steady growth in beneficial electrification starting in 2026.

Figure 6: Incremental Beneficial Electrification Growth Allocated in LoadSEER



As more iterations of load forecasting are completed in LoadSEER, forecast granularity and robustness improves over time as data and inputs improve.

VII. ACTION PLAN SUMMARY

The Company's Action Plan, which details both the near-term and long-term action plans, is detailed at Appendix C.

A. 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.

Throughout this IDP, we also discuss other near-term focus areas and priorities 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 prepare for the future, enable the clean energy transition, maintain and enhance resilience and reliability, and modernize the grid.

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 6: 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.
AMI	Meter deployment began in 2022, with anticipated completion in 2025.
FAN	The initial network and security design was completed in 2020. The first FAN device was installed and programmed in May 2021 and the installation and programming of additional FAN devices will continue through 2025. 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.
FLISR	Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The ADMS FLISR functionality will be available to the Minnesota control centers use starting in 2023 on select feeders and will be continued to be expanded to other feeders through 2027.

In addition to discrete grid modernizations investments, we are also taking near-term actions to improve the way that we are integrating DER and planning for longer-term implications and benefits of increased penetration levels. As DER penetration continues to increase on the distribution system, we recognize that we will need to regularly monitor and potentially update our interconnection and planning processes and operational technologies and protocols. Although we and the industry are in the early stages of the progression toward more advanced interconnection management, we are studying the technology requirements and the timing of their implementation that would be needed to enable the progression toward active management of DER interconnections. We discuss this progression further in Appendix E.

Moreover, the Company is making significant investments in EV-related programs intended to encourage greater adoption of electrified transportation options and to enable options that can lessen the burden EV charging can have on system resources. As EV adoption is rapidly increasing in Minnesota, the demand impact of EV charging will only continue to grow. The Company is attempting to combat these challenges through our EV charging options for both residential and commercial programs. The Company is also proposing a new demonstration project in our TEP that seeks to study and address barriers to school bus electrification, school bus bi-directional connection to the grid, and to better understand the costs and benefits of electric school buses as a grid resource.

Finally, the near-term action plan for Demand Side Management, which includes energy efficiency, demand response, and efficient fuel switching, will be largely determined through a combination of the Minnesota Energy Conservation and Optimization (ECO) Triennial (both current and future) filings and the next Integrated Resource Plan (IRP), which is due February 1, 2024.

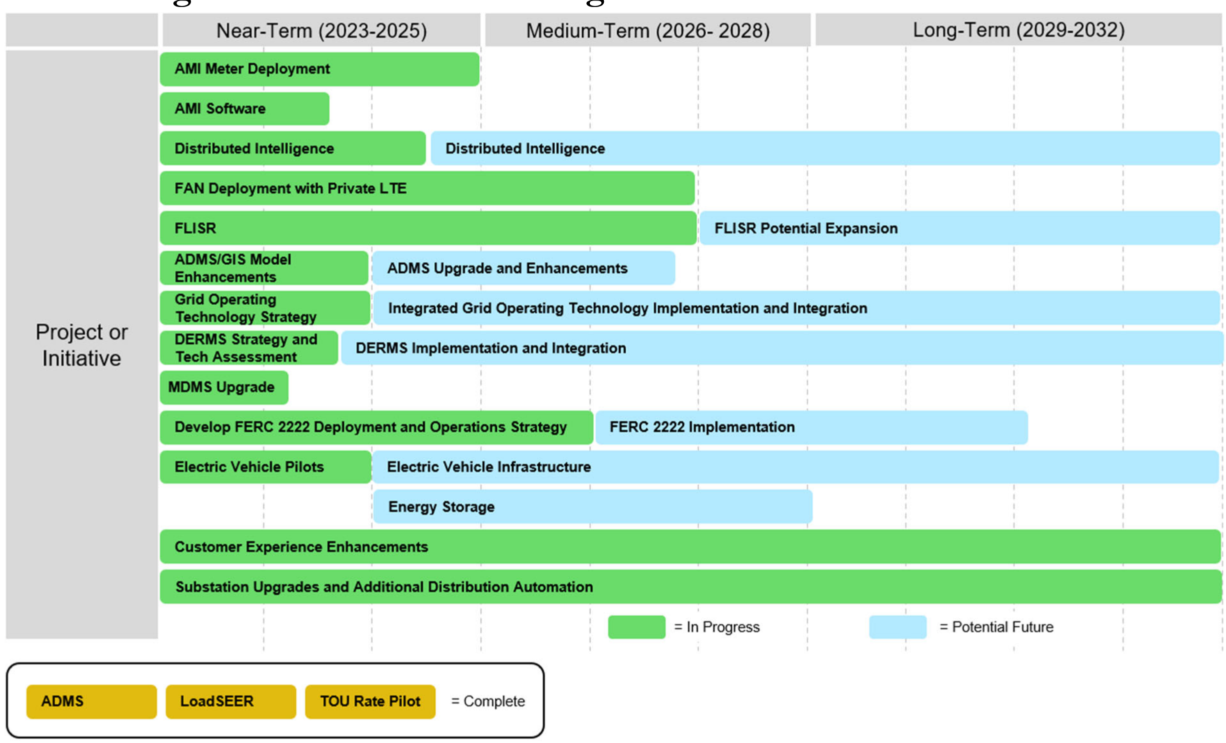
As we continue to maintain a safe, reliable, resilient, and affordable distribution system over the next five years, the new planning landscape, as discussed above, has the potential to challenge the current capabilities and resource requirements; we must ensure that our teams continue to have the appropriate skillsets, knowledge, and experience that will be necessary as the grid of the future takes shape. With the tools and strategies discussed in this IDP, 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.

B. Long-Term Action Plan

The Company's long-term action plan addresses a vision for the planning, development, and use of the distribution system over the next 10 years. Our long-term strategy incorporates not only the necessary work to maintain poles and wires, but also the work needed to prepare for the future, enable the clean energy transition, maintain, and enhance reliability and resilience, and modernize our customers' interactions with the distribution grid.

Importantly, with respect to grid modernization, a 10-year view of the sequencing of planned and potential advanced grid investments is shown in Figure C-3 below.

Figure C - 1: Illustrative Long-Term Grid Modernization Plan



In addition to grid modernization, DER penetration continues to increase, and we plan to continue to study DER interconnections and their impacts on the system on a case-by-case basis. We are further studying 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 include the analysis, planning tools and future systems, such as DERMS.
In addition to grid modernization, DER penetration continues to increase, and we plan to continue to study DER interconnections and their impacts on the system on a case-by-case basis. We are further studying 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 include the analysis, planning tools and future systems, such as DERMS.

CONCLUSION

The backbone of distribution planning is ensuring we have the right infrastructure in place to keep the lights on for our customers and to be ready to accommodate new customer load growth in a timely fashion. We continue to take 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. We take a long-term view of system planning to ensure that we can continue to maintain a safe, reliable system today while building the grid of the future.

Importantly, this document is intended to be an introduction and high level overview of the Company's IDP filing. Further detail and explanation is included in the attached Appendices as follows:

Appendix	Topic
A1	System Planning
A2	Standards, Asset Health and Reliability Management
A3	Distribution Operations
A4	Distribution System Statistics
B1	Grid Modernization
B2	Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies
B3	Existing and Potential New Grid Modernization Pilots
C	Action Plans
D	Distribution Financial Information
E	Distributed Energy Resources, System Interconnection, and Hosting Capacity
F	Non-Wires Alternatives Analysis
G	Stakeholder Engagement
H	Transportation Electrification Plan
I	Distribution System Improvements
J	Distributed Intelligence

As we prepare for the future, the evolving technology, policy interests, and customer expectations will continue to inform our strategy. The continued adoption of DER, electric vehicles, and other beneficial electrification technologies will require changes in the way we plan for and operate our grid. We are at a transformational time for the distribution system, and we appreciate the opportunity to share our plans with the Commission.

We respectfully request the Commission approve our IDP along with our proposed updates to the IDP filing requirements, namely, that the IDP Filing Requirements for the Company be revised to remove the requirement that financial information be reported in IDP-specific categories.

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.

In the remainder of this Appendix, we discuss our overall approach to system planning; load and distributed energy resources (DER) forecasts and forecast scenarios; the risk analysis process, including our initial methodology for planned net loading (PNL); and the other steps of our annual distribution system planning process. We note that for this year's IDP, for a more holistic view of our planning and forecasting processes, we have consolidated all of the forecasting information into this Appendix. We also present for the first time the results of our DER forecast scenarios from LoadSEER.

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 are advancing our planning and forecasting capabilities with our planning tool, LoadSEER.

The purpose of these assessments is to proactively plan for the future, maintain and improve resiliency, and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0) 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 constructing a new feeder or substation, adding feeder tie connections, rebalancing phases on feeders to accommodate more capacity, evaluating possible switching, installing regulators, installing capacitors, or upsizing substation transformers. As our planning processes evolve and technologies mature, we will continue to consider non-wires alternatives (NWAs), discussed further in *Appendix F: Non-Wires Alternatives Analysis*. For each project, we develop cost estimates 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 allocates funds to other distribution priorities and projects including asset health, grid modernization, and emergent issues. Emergent issues include 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 Appendix, we describe the Company's distribution system planning approach, including planning processes and tools used to develop the annual plans in compliance with IDP Requirements 3.D.2.m and 3.D.2.n, which require:

m. *The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.*

n. *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 Figure A1-1 below.

Figure A1 - 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 peak load versus previous annual peak loads,
- 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 2022. For this process, we used 2021 and 2022 actuals and historical peak information along with any known system changes to forecast the 2023 through 2027 peaks and perform our risk analysis based on the forecasted 2024 peak.

A. Current Planning Tools

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.

IDP Requirement 3.A.1 requires the following:

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

Table A1-1 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 A1 - 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 supervisory control and data acquisition (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 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.

Additionally, we outline our hosting capacity tool that is not currently part of the annual system planning process in Table A1-2.

Table A1 - 2: Hosting Capacity Tool

Tool	Process	Description
Electric Power Research Institute (EPRI) 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.

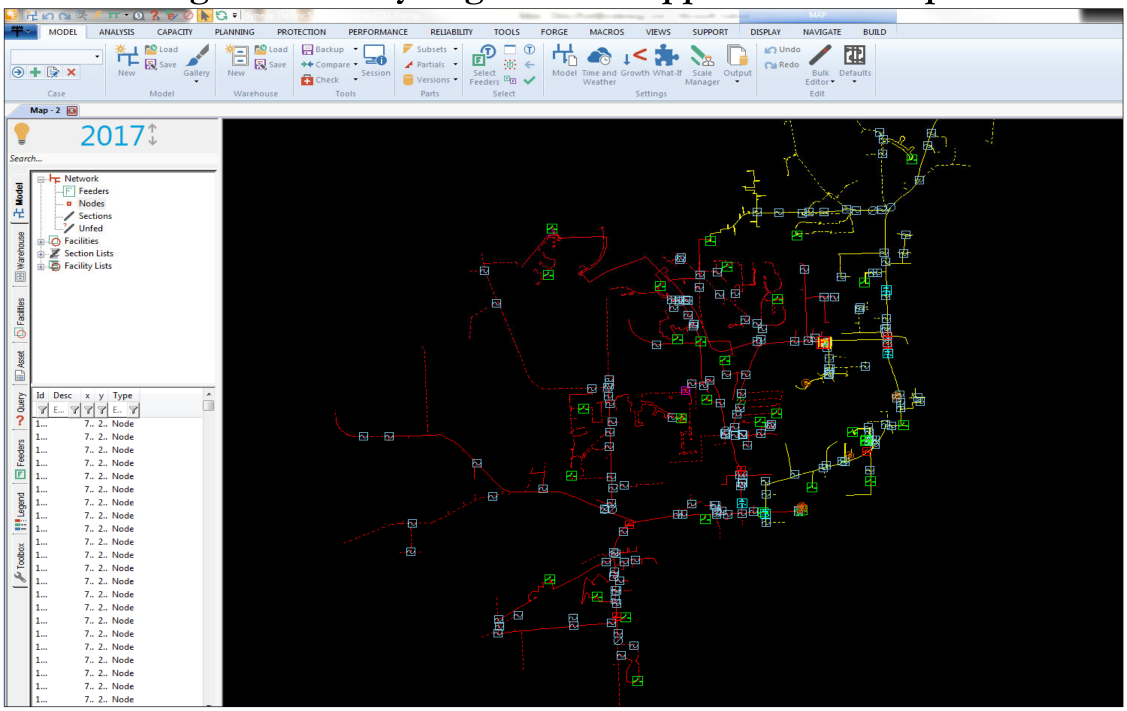
Table A1 - 3: Tool Summary by Distribution Planning Process

	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 A1-2 below.

Figure A1 - 2: 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.[1] 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, and other DER such as battery storage, so that those effects can be better accommodated.

Integral Analytics LoadSEER (Figure A1-3). 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 up 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.

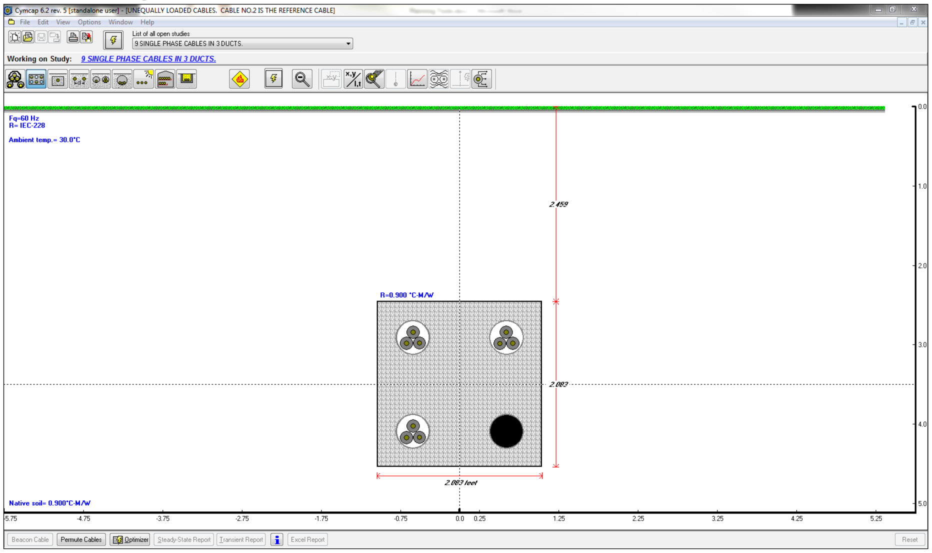
[1] For example, it ensures a potential residential customer receives more load at peak than a potential industrial customer with the same energy usage. This is because industrial customers typically have a flatter load profile curve. Accordingly, when industrial customers are compared to residential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

Figure A1 – 3: 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 (i.e., when the system 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 a fairly simple tool, these spreadsheets provide valuable information about our system that we call "Load at Risk," which we use to justify projects that keep our system reliably robust.

Eaton CYME CYMCAP (Figure A1-4). Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP considers 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 A1 – 4: CYMCAP Application Example



General Electric Smallworld Geospatial Information System (GIS). 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 the Company. 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.

For feeders where we have SCADA capabilities, we can 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.[2] The data is maintained in a data warehouse and combined with the historical LoadSEER hourly load data. When three phase Ampere data is available, we use the highest recorded phase measurement to determine facility loading. We discuss feeder load monitoring and SCADA further in *Appendix A4: Distribution System Statistics*.

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. This Microsoft Excel add-in 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 CSGs. 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.

B. Feeder and Substation Design

Distribution feeders for standard service to customers are designed as radial circuits, as illustrated in Figure A1-5. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system,

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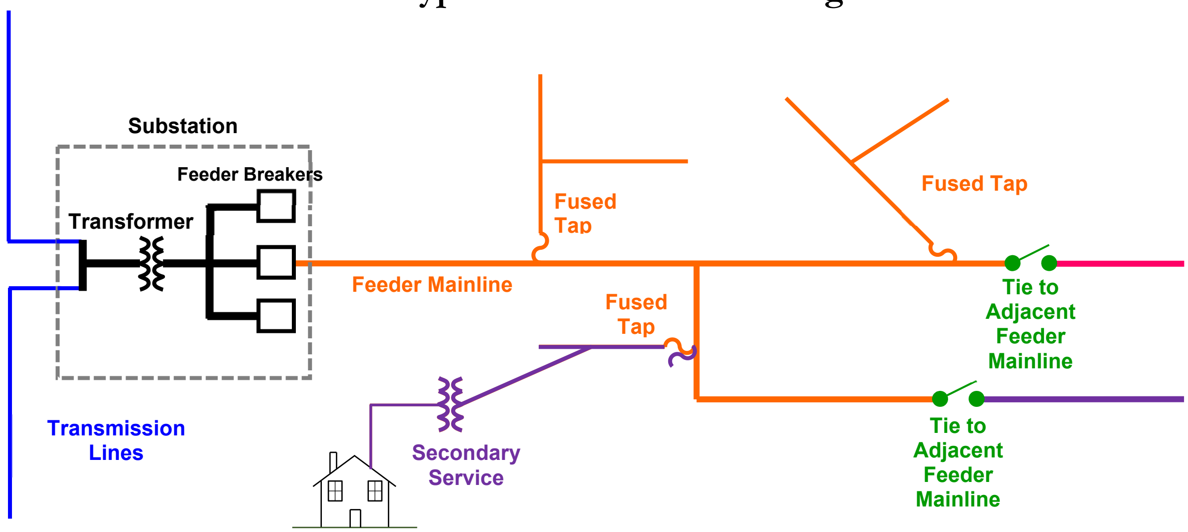
[2] This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults or other disturbances on the feeder.

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 A1 - 5: 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, 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, 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 affect substation capacity, system protection, and voltage regulation. Figure A1-6 shows a distribution substation.

Figure A1 - 6: Distribution Substation

Feeders are sized to carry existing and planned customer load and generation. 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 15 kilovolt (kV), 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 megavolt amperes (MVA) on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

C. Planning Criteria and Design Guidelines

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all 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 interconnect new customers more quickly, as well as provide increased operational capability and carry the load of adjacent feeders during first contingency N-1 conditions.[3]

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 power from a distribution substation transformer to customers. Three-phase electrical motors and other equipment is designed to operate best when the voltage on all 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.[4] We developed this standard to help 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 was an outage, the remaining system components would not be able to make

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[3] The five-year budget presented in *Appendix D: Distribution Financial Information* reflects the funding necessary to bring Minnesota feeder loading within this guideline.
[4] 23.9 kV and 34.5 kV follow a 50 percent loading rule.

up for the loss, because adding load to the remaining feeder circuits would cause them to overload.[5]

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 focuses on 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.

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 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

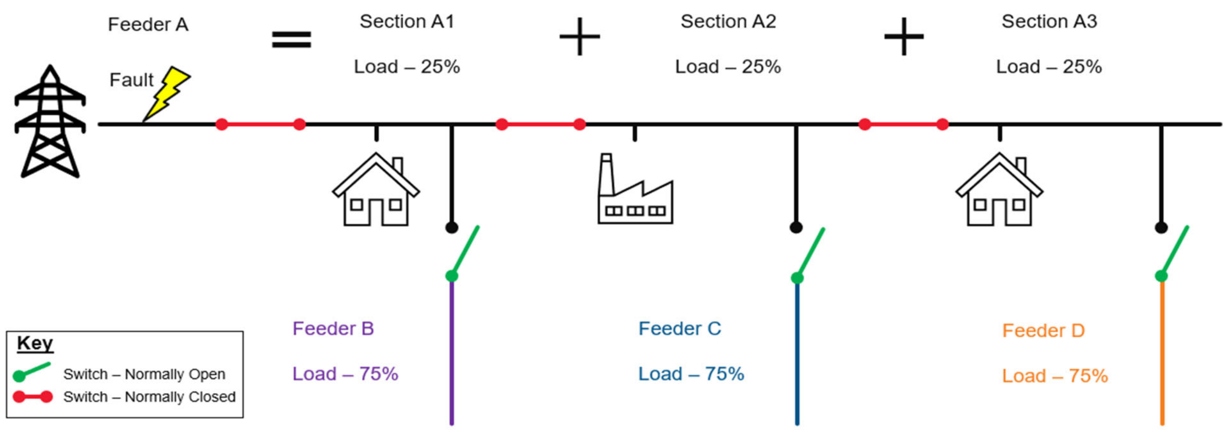
[5] By targeting a 75 percent loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A feeder circuit capable of delivering 12 MVA, for example, should be normally loaded to 9 MVA and loaded up to 12 MVA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

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 A1-7 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 A1 - 7: 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 A to D all have the same rated capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders B, C, and D through the corresponding tie switches. This reconfiguration results in Feeders B, C, and D each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder A 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 the equation shown in Figure A1-8 below), it is generally no longer effective to perform more simple solutions – such as feeder reconfigurations or installing new feeder tie connections between existing feeders.

Figure A1 - 8: 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 64 percent; approximately 31 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 N-1 overload.

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.

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 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.

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 SCADA system connection, we can monitor the real-time load on the transformer. Like distribution feeders, the transformer data feeds into a data warehouse, which can be combined with historical peak load data in LoadSEER, 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.

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.

The Commission's July 26, 2022, IDP Order in Docket No. E002/M-21-694 requires that the Company begin prioritizing the use of "net load" in the load forecast processes.[6] Compared with "native loading," the net load accounts for how the presence of DER generation on the distribution system reduces the effective demand on the distribution system as measured from the substation. In response, the Company has developed an initial methodology called "Planned Net Load" to represent how net load can prudently be incorporated in the distribution planning process. This methodology would allow for the consideration of certain distribution substations and feeders to have a reduced risk due to the existing DER on the distribution system. We discuss our initial methodology in Section III.B.

D. Integrated System Planning

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, including:*
>
> a. *Setting the forecasts for distributed energy resources consistently in its resource plan and its IDP.*
> b. *Conducting advanced forecasting to better project the levels of distributed energy resource*

[6] Order Point 6 outlines the topics covered in the required stakeholder series. Order Point 6.f states that the stakeholder series should include the topic of "Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning process."

deployment at a feeder level, using Xcel's advanced planning tool.

c. *Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources.*
d. *Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources.*
e. *Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.*

In this section, we discuss the overall planning landscape and evolution of our integrated system planning approach. Then, we address each subpart of IDP Requirement 3.A.5.

Achieving the goal of a sustainable, clean energy future depends upon having sufficient infrastructure to support delivery of renewable and distributed generation resources and customer reliability. Modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, deliver growing levels of choice, increase renewable energy, meet the challenges of emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation: safely and reliably delivering energy to our customers. We are also focused on adopting smarter technologies to further enable DER on our system. Additionally, we face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DERs are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER impacts on the transmission grid, changes in the market and planning constructs are underway. Recent policy changes are also driving the need to evolve planning. The federal Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) have myriad avenues for acquiring funding and tax incentives, which will impact how the Company and the energy industry at large will proceed with planning, while the "100 x 40" law passed by the Minnesota Legislature contains a roadmap to 100 percent carbon-free electricity, which will also impact resource, transmission, and distribution planning. We are adapting our planning practices in the interim to ensure reliability and resilience, including development of substantial new transmission, which will be needed to support the transformation that is underway.

Overall, we envision continuing to build on our planning capabilities for an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We also envision a highly integrated operating technology environment.

This need for long-term planning that considers the impacts of generation, transmission, and distribution on each other spurred the creation of the Integrated System Planning (ISP) business unit within the Company. The purpose of ISP is to develop generation, transmission, distribution, and natural gas infrastructure investment plans that deliver on the Company's sustainability goals while keeping bills low and enhancing the customer experience. ISP also bridges the gaps between modeling tools with human processes in addition to tackling challenges of the overall planning landscape, such as inflection points with technologies – such as EVs and beneficial electrification – and pricing. The Company's, and indeed the industry's, exploration of integrated planning frameworks is nascent and will continue to evolve and improve as we make progress toward a clean energy future and our vision to be the preferred and trusted provider of the energy our customers need.

Below, we address each subpart of IDP Requirement 3.A.5.

1. DER Forecast Consistency

IDP Requirement 3.A.5.a requires discussion of planning modifications or changes to improve coordination and integration between the IDP and the Integrated Resource Plan (IRP), including:

> *Setting the forecasts for distributed energy resources consistently in its resource plan and its IDP.*

While forecasting plays a role in both the IRP and IDP, the processes are fundamentally different and serve disparate functions. The IRP process is a long term (15-year) resource planning process that has been in place for decades and is governed by established Minnesota Statutes and Rules (which result in Orders that constitute prima facie evidence in other proceedings). Similarly, transmission planning is largely governed by the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) requirements and overseen by the Midcontinent Independent System Operator (MISO). The IDP process is nascent by comparison – intended to be informational in nature – and is based on a set of reporting requirements that the Commission has established on a utility-by-utility basis. While IDP requirements may change over time, evolving it to have an IRP-like process would require significant time, work, and stakeholder input – and that is only if the Commission desires to evaluate or pursue such a change.

Another key difference between the IRP and the IDP is the time horizon and planning cycle duration and cadence. The IRP indicates size, type, and timing of resource needs over a 15-year time horizon, while the IDP shows a five-year budget of discrete projects and investments. The five-year budget shown in the IDP is built every year on the forecast from the previous autumn, i.e., the five-year budget presented in this IDP is based on forecast data from Fall 2022, and we will soon begin our next planning cycle using an updated forecast. This is significantly different in the IRP, where the modeling happens only one to six months in advance of the filing date, every few years. The required DER scenario analysis reflected in the IDP, for which we use LoadSEER, happens somewhat closer to the IDP filing date.

Despite the fundamental differences between the purposes of the IRP and the IDP, there are opportunities to align some of the forecast vintages used in the creation of both filings. Additionally, because the different aspects of the Company's system – generation, transmission, and distribution – are interconnected and impact one another, we are taking distribution system additions that are selected in the IRP process into account in future forecasts that inform the IDP budget. We are using the same forecasts in similar ways in both the IRP and IDP to align the plans, but if a new version of a forecast comes out after the completion of the distribution planning cycle reflected in the IDP but before the IRP, it is appropriate that the IRP should use the more recent forecast vintage – and vice versa. This issue cannot be addressed by filing the IRP and the IDP on the same day because, as previously mentioned, the forecast for the IDP happens at the beginning of the planning process – over one year in advance – whereas the IRP modeling happens much closer to the filing date. Finally, the sensitivity and scenario analyses presented in the IRP and the IDP serve to capture the minimal year-to-year variation in base forecasts.

As we will discuss throughout Section II, there are many components to our DER forecast, including forecasts for Distributed Solar PV, CSG, Distributed Energy Storage, Energy Efficiency, Demand Response (DR), and Electric Vehicles. Table A1-4 notes which modeling vintages are reflected in the corporate-level DER forecasts shown in Section II.B. However, the LoadSEER modeling that was done by Distribution Planning to develop the DER forecast scenarios in Section II.C began prior to some of these vintages being made available. Therefore, we also describe the vintage used in our LoadSEER modeling below as well.

Table A1 - 4: Forecast Vintage Comparison

Forecast	Vintage Reflected in Corporate-Level DER Scenario Modeling	Vintage Used in LoadSEER DER Scenario Modeling
Distributed Solar PV	June 2023	June 2023
Community Solar Gardens	August 2023	August 2023[7]
Distributed Energy Storage	September 2023	2021 IDP
Energy Efficiency	September 2023	Embedded in 2022 Energy Sales & Demand forecast
Demand Response	2022	Embedded in 2022 Energy Sales & Demand forecast
Electric Vehicles	July 2023	2022

Per the Commission's Order,[8] we are making efforts to set the forecasts for DER consistently between our IDP and IRP. However, because of the modeling timeline for the IRP, finalization of the IRP models is not complete at the time of this IDP submission. Therefore, we will be providing more information about coordination of distribution system planning and setting the forecasts for DER consistently between the IDP and the IRP in our forthcoming IRP, which is due February 1, 2024.

2. Feeder-Level DER Forecasting in LoadSEER

IDP Requirement 3.A.5.b requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

> *Conducting advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool [LoadSEER].*

As noted above, there are fundamental differences between the functions of the IRP and the IDP processes, but we are taking steps to integrate our planning processes. Resource planning identifies the size, type, and timing of the system's needed resource mix – it has not traditionally considered location, although certain modeling proxies may be able simulate locational constraints in an IRP process. Distribution planning by contrast is highly location-based. As we explain in detail in Section II.C below, LoadSEER enables advanced forecasting at the feeder level. DER that is approved as part of our IRP feeds into the base forecast and is then spatially allocated within

[7] This scenario includes a forecast for solar that will meet Distributed Solar Energy Standard (DSES), Minn. Stat. § 216B.1691, subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16, and is discussed in section II.C.7.
8 July 26, 2022, Order, Docket No. 21-694, Ordering Paragraph 4.

LoadSEER, which is an important tool for our planning process, which prioritizes and budgets for specific system upgrades and investments that can accommodate DER that is planned as part of the IRP.

3. Proactive Capacity Investments to Allow DG and EV Additions Consistent with the DER Forecast

IDP Requirement 3.A.5.c requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

> *Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources.*

First, as discussed in the IDP Main Report, the evolving and expanding expectations of the grid present opportunities for the Company to revolutionize the distribution system. Along with those opportunities come significant challenges, including keeping costs low. As customers, stakeholders, and policymakers seek increased system investment to enable DER additions and other grid capabilities, how to fund those significant investments remains a crucial question that is coming to the forefront of the energy transition. Preemptive investments can be difficult to justify, as evidenced by the record development and Commission action regarding our proposed Grid Reinforcements program in the 2021 rate case (Docket No. E002/GR-21-630). We proposed approximately $12 million in capital additions to help prepare our system for increased load growth from EVs and beneficial electrification by replacing and upgrading service-level transformers. Parties found the program to be too speculative, and the Commission rejected the capital additions.

We believe there is value in proactive investments, and we will continue to bring them forward in future rate cases where appropriate. Within this context, for the first time, in our five-year budget presented in *Appendix D: Distribution Financial Framework and Information*, we have included funds for significant investments in proactive hosting capacity upgrades in 2025 through 2028. Specifically, we have included $190 million for system upgrades to increase hosting capacity, which would enable more DER interconnection and increased load. We note that the program is not yet fully scoped and should be considered a placeholder at this time. We are interested in hearing from stakeholders and the Commission on how we should approach proactive investments in hosting capacity, including how we should potentially prioritize such investments over others. In addition, today, we are filing our Distribution System Upgrade Plan with the Minnesota Department of Commerce, pursuant to Minn. Stat. § 216C.378 as added by Minnesota Session Laws, 2023, Regular Session Chapter 60 (H.F. No. 2310).

In addition to aligning the DER forecasts in the IRP and the IDP as much as practicable, in our forthcoming IRP, we will be including DG bundles as a selectable resource, pursuant to the Commission's IRP Order.[9] If a resource plan approved by the Commission includes incremental DER, that amount would be reflected in future iterations of our base DER forecasts. Electrification such as EVs, DR, and energy efficiency are reflected in the overall load forecast for the IDP. Our annual distribution planning cycle ensures that we are consistently revising and refining our plans if forecasts shift.

4. *Improving Non-Wires Alternatives Analysis*

IDP Requirement 3.A.5.d requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

> *Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources.*

We have been continually improving and expanding our NWA analysis. As discussed in Appendix F, the stacked values used in our NWA analysis are consistent with the IRP assumptions, where applicable. Given the inherent differences in timing of the two filings and the time at which we must begin our NWA analysis, however, some assumptions align with our last *approved* resource plan but do not align with the modeling assumptions that will be used in our *forthcoming* resource plan to be filed February 1, 2024. For example, the WACC discount rate varies slightly; our next IRP will use the WACC from the latest Commission-approved capital structure in Docket No. E002/GR-21-630, but we did not have time to make that adjustment between the time of the rate case Order and when we needed to begin this year's NWA analysis for this filing. In addition, the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline, from which many of our technology cost assumptions are sourced, does not reflect potential tax credits for battery energy storage. Although we are making an adjustment for our IRP modeling, we did not have time to incorporate that adjustment into this year's NWA analysis. We will continue to evaluate our modeling assumptions and strive to match them between the IRP and NWA analysis whenever practicable and applicable.

[9] ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS, Docket No. E002/RP-19-368, April 15, 2022, at Order Point 15.

We have not yet issued market solicitations for deferral opportunities, but as discussed in Appendix F, this year's NWA analysis shows three potentially viable and cost-effective projects. All three of these potentially viable projects have in-service dates in 2028. Given that timeline, we will have another opportunity to run our NWA analysis next year as part of our annual NWA analysis update before additional steps are taken. If any of the projects remain potentially viable and cost-effective, we would then determine next steps in the next IDP Annual Update filing in 2024.

In addition, new legislation will require the Company to add and enable more DER, including batteries and distributed solar. In the future, with a Distributed Energy Resources Management System (DERMS) in place, we may be able to identify and take advantage of multi-value projects.

5. Planning for Aggregated DER

IDP Requirement 3.A.5.e requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

> *Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.*

We note that in the context of the IDP, the Commission defines DER as "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, and may include resources such as distributed generation, energy storage, electric vehicles, demand side management, or energy efficiency."[10]

For distribution system planning, as we explain further in this Appendix, we plan for peak loads at a more granular, location-specific level than bulk system planning. Additionally, the assumed "use cases" for various DERs in distribution system planning may differ from the use case(s) assumed in bulk system planning for the IRP.[11] In these ways, "system value" may mean something different in the context of distribution system planning versus resource planning.

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[10] IDP Requirement 3.

[11] Examples of use cases can be seen here: https://www.nrel.gov/state-local-tribal/blog/posts/batteries-101-series-use-cases-and-value-streams-for-energy-storage.html. Each of these use cases uses Battery Energy Storage Systems in a different way, including potential different times of needed availability and charging.

From a distribution system perspective, through our NWA analysis, we annually evaluate and plan for combinations of DERs to provide value during peak times at the feeder and substation level. Further, our NWA analysis considers the effects of DR and distributed solar already present on a given feeder or substation.

From a resource planning perspective, we have many DR and energy efficiency programs that can be considered "aggregated" in the sense that they are designed to benefit the bulk system. Although these aggregated resources may also benefit the distribution system at the times of feeder and substation peak times, the primary optimization criteria and assumptions used in the IRP seek to benefit the bulk system at times of peak system demand on the bulk system, as well as use cases that are optimal for bulk system planning.

Our forthcoming IRP will include incremental DR, energy efficiency, and distributed solar as selectable resources. To the extent any incremental DER is approved as part of a resource plan, that amount of DER would be reflected in future base DER forecasts reflected in the IRP and IDP.

II. LOAD FORECAST

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

A. Planning to Meet Peak Load

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: Action Plans* for the load forecast resulting from this analysis in compliance with IDP Requirement 3.D.2, which requires, in part, that we provide our load growth assumptions and how we plan to meet it in our five-year action plan. We additionally provide our long-term system load projections in compliance with IDP Requirement 3.D.3 in Appendix C.

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 meet regularly as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system. The interaction between distribution planning and transmission planning has increased recently with the inception of the Company's new Integrated System Planning organization, discussed above.

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve loads during system peaks.[12] 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.

Finally, the Commission's July 26, 2022 IDP Order in Docket No. E002/M-21-694 requires the Company to begin prioritizing the use of "planned net loading" (PNL) in the load forecast processes.[13] Compared with "peak loading," the PNL would account for how the presence of DER on the distribution system offsets the absolute peak demand at any given time. This new initial methodology would allow for the consideration of certain distribution substations and feeders to have a reduced risk due to the load-masking impact of existing DER on the distribution system. This is further expanded upon in Section III.B below.

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

[13] Order Point 6 outlines the topics covered in the required stakeholder series. Order Point 6.f states that the stakeholder series should include the topic of "Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning process."

B. 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.*
>
> *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.*
>
> *For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).*

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.*

The forecasts below represent our corporate DER forecasts and associated scenarios, which do not always align with the +10 percent and +25 percent scenarios outlined in IDP Requirement 3.C.2. As we will discuss in Section II.C below regarding the LoadSEER DER forecast scenarios, we use the corporate DER forecasts discussed in this section, unless otherwise described, and create separate LoadSEER scenarios that generally use low, medium, and high adoption rate scenarios corresponding to base, base+10 percent, and base+25 percent, unless noted otherwise.

We have also worked to align scenario inputs between the IDP and the IRP. As discussed in Section I.D above, there are significant differences between the purpose, functionality, and timing of the IDP and the IRP, which affects the vintages of forecasts that are most relevant at the time of modeling. Due to the timing cadences for these filings, modeling for the IRP is still in progress. We will provide more information about our efforts to align modeling scenario inputs between our IDP and IRP in our forthcoming IRP, which is due February 1, 2024.

Tabular data in live Excel format for the forecasts below is provided as Attachment M.

1. DER Treatment in the Corporate Load Forecast

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.

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 adjust 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 Company 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. 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.

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.

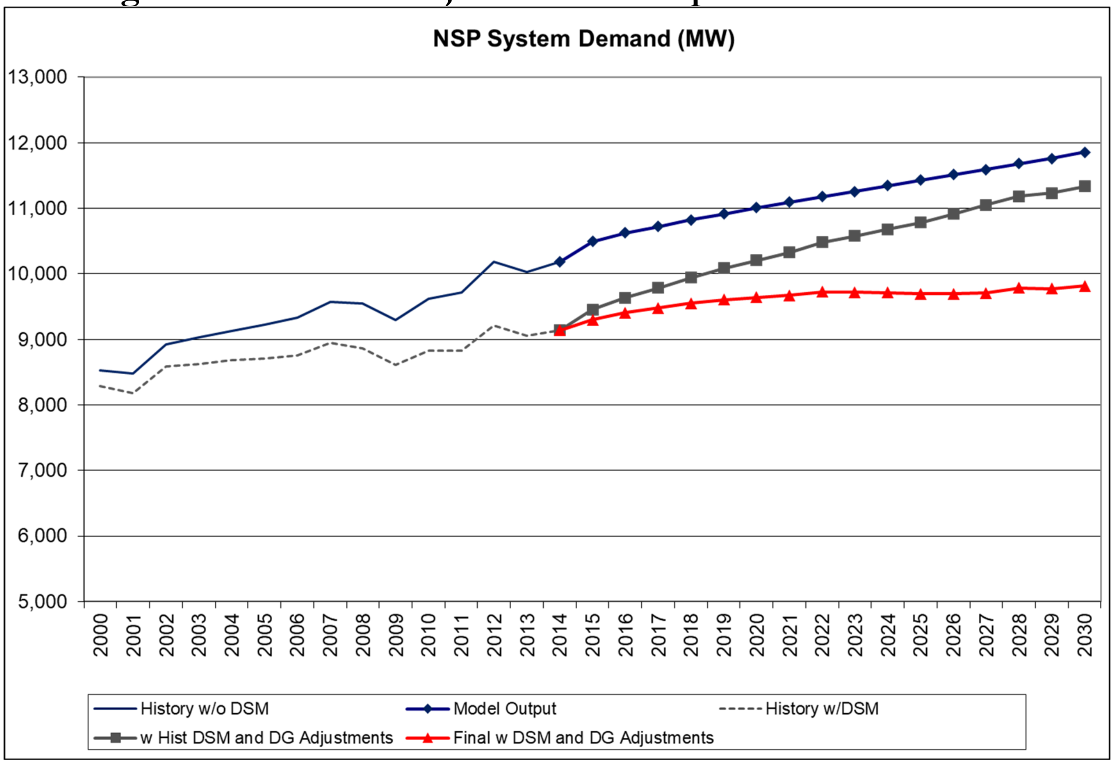
Demand-Side Management Programs. One important adjustment to the forecasts is the impact from our conservation improvement programs. The sales model implicitly accounts for some portion of changes in customer use due to conservation and other influences by basing projections of future consumption on 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 Demand Side Management (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 A1-9 graphically illustrates the DSM adjustment described above.

Figure A1 - 9: DSM Adjustment in Corporate Load Forecast



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 CSGs 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 below. 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 adjust 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 in order to reduce our requirements due to the scheduled installation of a customer-owned Combined Heat and Power generator.

Data Sources:

- *Megawatt-hour (MWh) Sales and megawatt (MW) Peak Demand.* The Company 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 the Company'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 temperature-humidity index 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 EVs in 2018.

2. 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 CSGs in our Solar*Rewards Community program. Until its discontinuance in October of 2018, customers also had the opportunity to participate in the Made in Minnesota program. In addition, for larger systems, we offer a net-metering option. We have factored all these distributed solar PV options into our low, medium, and high distributed solar forecasts. As we will discuss further below, the rooftop solar forecast is from June 2023 and the CSG forecast is from August 2023.

In determining our Solar*Rewards forecast, we updated our goals to be consistent with legislative outcomes that increased and provided incentive Solar*Rewards funding for 2023-2025. The funding for the Made in Minnesota awards program was eliminated in 2017. The Solar*Rewards installations for 2023-2026 were estimated based on historical trends of funding levels and project conversion rates.

The Low, Medium, and High scenarios hold the Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSGs, 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 net metered 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 2022. 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 (e.g., renters, shaded roof, inability to access the roof, etc.). 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 the High scenario using a combination of lower installation cost and higher savings. The High scenario assumes the installation costs decrease at a faster rate than the medium scenario. The Bass Diffusion High scenario uses higher coefficients compared to the medium case. These coefficients were calibrated using a section of the historical curve that showed higher than average growth.

The Low scenario assumes the installation cost decreases at a slower rate than the medium case. The Bass Diffusion Low scenario uses lower coefficients compared to the medium case. These coefficients were calibrated using a section of the historical curve that showed lower than average growth.

The Bass Diffusion model was also used in determining the Medium and Low scenarios for the CSG forecasts. The high case matches the annual cap for CSGs established in the legislation (100 MW/year, then 80 MW/year, then 60 MW/year).[14] For the medium case, the Bass Diffusion is calibrated using state-specific historical data and constraints by expected available capacity on the distribution system over the next 10 years. For the low case, the Bass Diffusion is calibrated using recent years that assumes the historical downward trend in CSG adoption will continue.

The Low scenario model results indicate around 1,525 MW for total installed distributed solar by 2033. The Medium scenario shows installed solar at approximately 2,097 MW by 2033, and the High scenario shows installed distributed solar at approximately 2,537 MW by 2033.

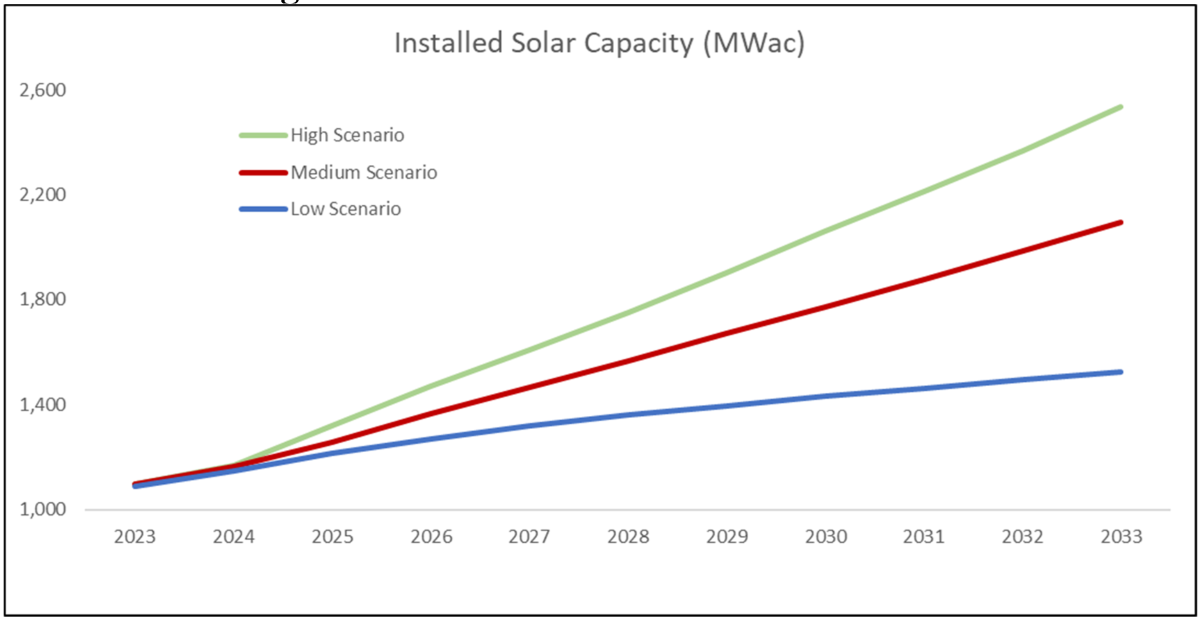
We provide a tabular and graphical view of the forecast in the following Table and Figure.

Table A1 - 5: Distributed Solar PV Forecast

	Total Low (MWac)	Total Medium (MWac)	Total High (MWac)
2023	1,091	1,098	1,098
2024	1,150	1,164	1,167
2025	1,216	1,258	1,320
2026	1,271	1,364	1,472
2027	1,318	1,467	1,610
2028	1,360	1,568	1,751
2029	1,396	1,670	1,900
2030	1,431	1,773	2,061
2031	1,464	1,878	2,211
2032	1,495	1,987	2,369
2033	1,525	2,097	2,537

[14] Minn. Stat. § 216B.1641 as amended by 2023 Session Laws Chapter 60, Article 12, Section 14.

Figure A1 - 10: Distributed Solar PV Forecast



3. DER Forecast – Distributed Wind Generation

We believe future DER growth will primarily be through solar PV and distributed storage, and that 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.

4. DER Forecast – Distributed Energy Storage

Through the end of 2022, we have 364 energy storage systems on our Minnesota electric distribution system. The total behind-the-meter battery storage installed on our Minnesota distribution system was approximately 1.565 MW at the end of 2022. We provide an annual breakdown in Table A1-6.

Table A1 - 6: Storage Systems – NSPM State of Minnesota

Time Period	Cumulative Systems	Cumulative kW (Max Continuous)
2017	8	35
2018	37	175
2019	62	289
2020	123	560
2021	189	841
2022	364	1565
2023 YTD[15]	493	2108

We updated our corporate energy storage forecast in September 2023 – after we had begun our LoadSEER forecasting. Therefore, our LoadSEER forecast scenarios for energy storage, described below, are based on the corporate distributed energy storage forecast from the 2021 IDP – the most recent available at the time we needed to begin our analysis. We will incorporate the 2023 forecast into the next iteration of our LoadSEER forecast.

In order to forecast the distributed storage for our system, we used the Bass Diffusion model for Scenario 2, entitled "Mid". The model is calibrated using the actual number of storage systems installed in the NSP Minnesota service area. Table A1-7 and Figure A1-11 show the distributed storage forecast in MW.

Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Typically, distributed energy storage systems are paired with a solar PV system. Therefore, the modeling technique to develop the low and high battery storage adoption scenarios utilizes as an input the rooftop solar PV forecasts and calculates the percentage of those systems that will incorporate energy storage.

For Scenario 1, entitled "Low", we apply the annual percentage to the low solar adoption scenario and for Scenario 3, entitled "High", we apply the annual percentage to the high solar adoption scenario.

The "Low" scenario results in a cumulative total of 2,688 energy storage units deployed within the NSP Minnesota electric distribution system by the end of 2033.

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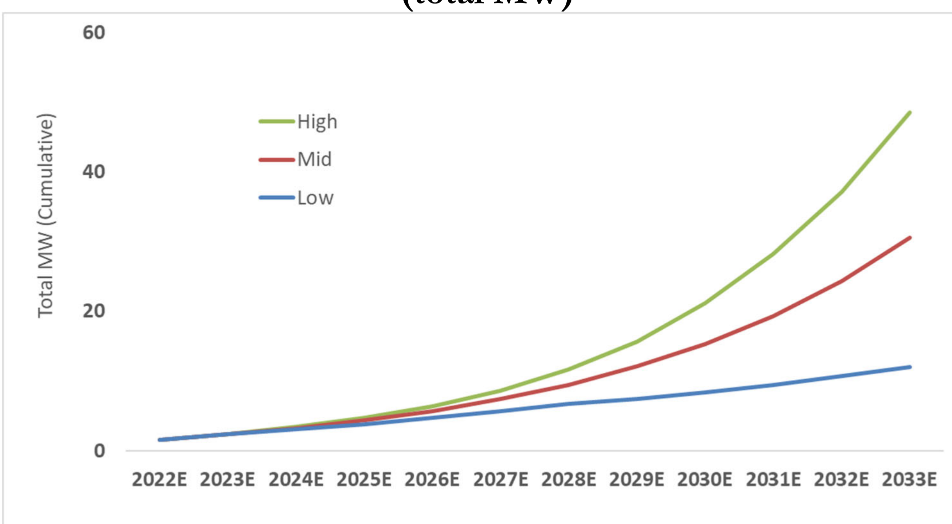
[15] 2023 YTD is through August 2023.

The "Mid" case estimates a cumulative total of 6,801 units deployed, while the "High" case estimates a cumulative total of 10,810 deployed by end of 2033.

Table A1 - 7: Distributed Storage Forecast – NSPM State of Minnesota

	Low (MWdc)	Medium (MWdc)	High (MWdc)
2023	2.4	2.4	2.4
2024	3.1	3.3	3.4
2025	3.8	4.4	4.7
2026	4.7	5.7	6.4
2027	5.7	7.4	8.6
2028	6.7	9.5	11.6
2029	7.5	12.1	15.7
2030	8.4	15.3	21.2
2031	9.5	19.3	28.2
2032	10.7	24.3	37.1
2033	12.1	30.5	48.5

Figure A1 - 11: NSP Distributed Storage Forecast – Minnesota (total MW)



Due to the emerging 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 supply chain disruptions that could negatively impact the availability of raw materials.

5. DER Forecast – Energy Efficiency

Demand Side Management, or what we call Energy Conservation and Optimization (ECO) in Minnesota, delivers energy and cost savings for customers. In addition, energy efficiency reduces the capacity needs on the distribution system. The Company has one of the longest-running and most successful DSM programs in the country. Our DSM programs have saved over 11,700 GWh of energy and over 4,100 MW of demand since 1990. 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. Most recently, the Company submitted their first ECO triennial plan, which is the first plan submitted under the 2021 ECO legislation to include additional customer opportunities in fuel switching and load management/DR. This filing in Docket No. G,E002/CIP-23-92, has yet to be considered by the Department of Commerce for the 2024-2026 Triennial period.

Our corporate energy efficiency forecast was updated in September 2023 – after we had begun our LoadSEER forecasting. Therefore, our LoadSEER forecast scenarios for DSM (and DR), described below, are based on the 2022 Forecast, which did not include the forecast or changes proposed in our 2024-2026 Triennial plan. These will sync up during our next resource plan. When this forecast is allocated to the distribution system, it is included in the impacts of the corporate energy sales and demand forecast, so while DSM impacts are included in the forecast, they are not discretely modeled.

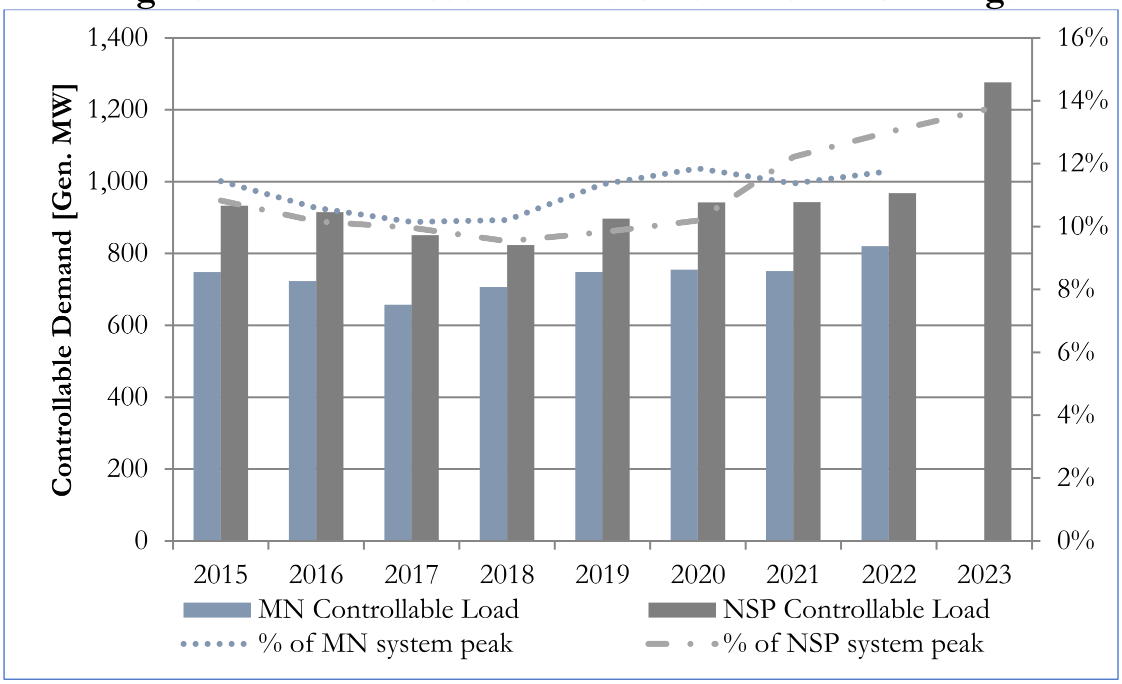
6. DER Forecast – Demand Response

The Company provides customers several opportunities to control their energy during times of system peak. Programs such as the Residential DR program provide opportunities for residential customers to lower their energy usage during system needs through active or passive participation. Products, such as Saver's Switch, are connected to a residential AC unit that automatically cycles a customers' equipment during a system peak. AC Rewards allows customers to choose their participation of demand reduction based on an active call. 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.

Most DR programs are intended to control during a system peak and not based on distribution level needs. However, our residential programs are grouped for distribution needs as determined by the Company. Additionally, the Company reviews the impact on specific substations and feeders as part of the NWA analysis and described in more detail in Appendix F.

The Company continues to grow our demand response resources. Our resources show an expedited increase through 2023. Further, we anticipate further growth with the additional opportunities presented by Advanced Metering Infrastructure (AMI) in the future and a potential future DERMS. Figure A1-12 below provides an outlook on the forecast for Demand Response through 2023.

Figure A1 - 12: Minnesota DR Forecast – Demand Savings



As noted above regarding DSM, the Company utilized the corporate energy forecast for demand response, which includes this increase in load. When this forecast is allocated to the distribution system, it is included in the impacts of the corporate energy sales and demand forecast, so while demand response impacts are included in the forecast, they are not discretely modeled.

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.

We further continue our exploration of new technologies and opportunities to shift load rather than shed only during system peaks; these options are discussed in our 2024-2026 Triennial Plan.

7. DER Forecast – Electric Vehicles

IDP Requirement 3.C.1 states in part:

> *For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).*

With an increase of available models, EV adoption has increased to approximately 34,500 light-duty EVs in Xcel Energy's Minnesota service territory as of June 2023. The EV forecasts discussed below were updated in July 2023.

We currently estimate light-duty 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 total cost of ownership to estimate potential adoption and represent the second approach in modeling EV adoption.

We have estimated a low, medium, and high total cost ownership model scenario for EV ownership compared to traditional internal combustion engine (ICE) automobiles. An average of the both the Bass Diffusion and total cost ownership models are used as an estimate of EVs. Our cumulative medium adoption estimate for 2023 is approximately 7.8 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 2022. 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 25 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 factors such as trade and tariff issues; availability of raw materials such as lithium, cobalt, and 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 Tables and Figures, the range of high and low estimates is large, reflective of the sensitivities, volatility and uncertainty associated with the estimates.

Table A1 - 8: Forecasted EV Adoption Numbers – NSPM Service Territory (July 2023 Forecast Vintage)

EV Type and Scenario	2025	2030	2033
Light-duty (LDV) (Low)	51,452	156,949	350,418
Medium-duty (MDV) (Low)	388	1,848	3,831
Heavy-duty (Low)	122	1,218	2,691
Total (Low)	**51,962**	**160,014**	**356,940**
LDV (Mid)	65,836	241,854	541,859
MDV (Mid)	496	2,847	5,925
HDV (Mid)	156	1,876	4,161
Total (Mid)	**66,488**	**246,578**	**551,944**
LDV (High)	106,082	542,792	994,338
MDV (High)	1,339	7,190	12,391
HDV (High)	443	4,793	8,785
Total (High)	**107,864**	**554,775**	**1,015,514**

Table A1 - 9: Forecasted EV Load – NSPM Service Territory (July 2023 Forecast Vintage)

	2025		2030		2033	
EV Type and Scenario	MW[16]	MWh	MW	MWh	MW	MWh
LDV (Low)	26	208,425	107	645,926	269	1,498,488
MDV (Low)	1	10,197	6	48,606	13	100,781
HDV (Low)	0	15,977	14	159,243	32	351,905
Total (Low)	**28**	**234,600**	**127**	**853,774**	**314**	**1,951,174**
LDV (Mid)	38	258,996	175	988,218	426	2,311,561
MDV (Mid)	2	13,048	9	74,900	21	155,840
HDV (Mid)	0	20,444	21	245,388	50	544,158
Total (Mid)	**40**	**292,488**	**205**	**1,308,507**	**496**	**3,011,560**
LDV (High)	72	376,277	415	2,204,257	858	4,395,151
MDV (High)	5	35,233	24	189,136	44	325,943
HDV (High)	1	57,890	54	626,829	107	1,148,893
Total (High)	**78**	**469,401**	**493**	**3,020,222**	**1,010**	**5,869,986**

[16] MW in this table is peak demand, incremental to current peak demand levels, for each vehicle class within the corresponding year.

Figure A1 - 13: Cumulative EV Adoption Rate (LDV) – NSP Minnesota Service Area

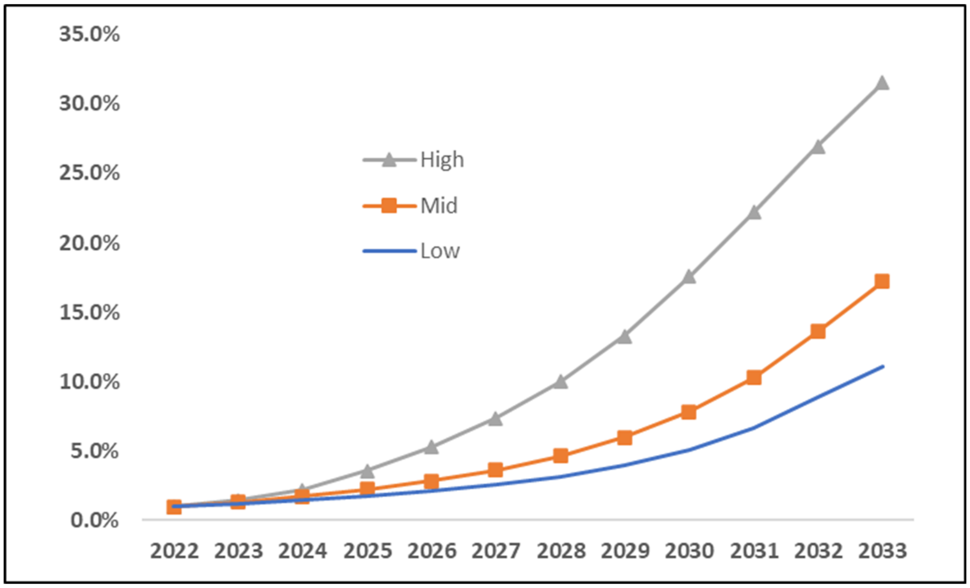


Figure A1 - 14: Cumulative Numbers of EVs – NSP Minnesota Service Area

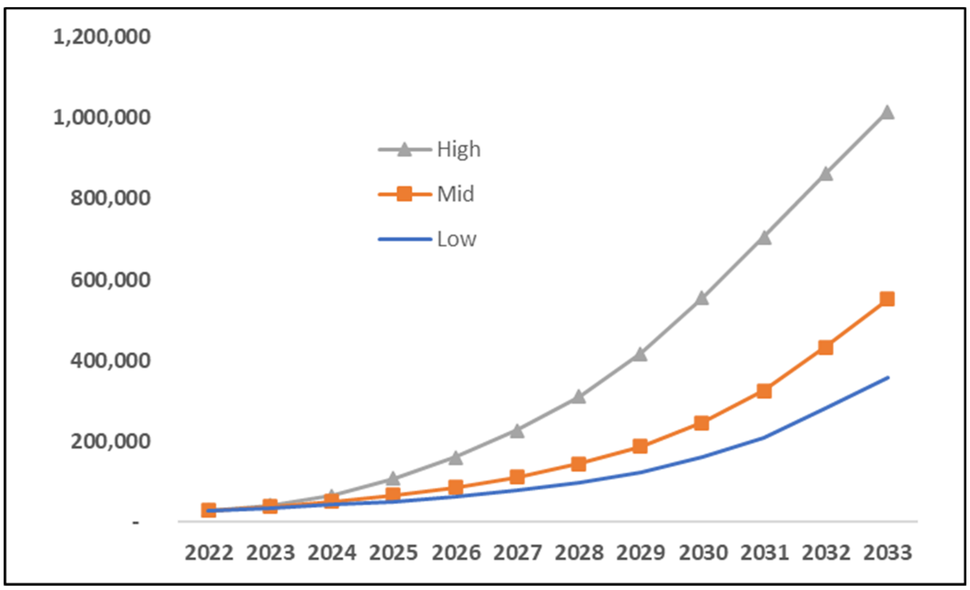
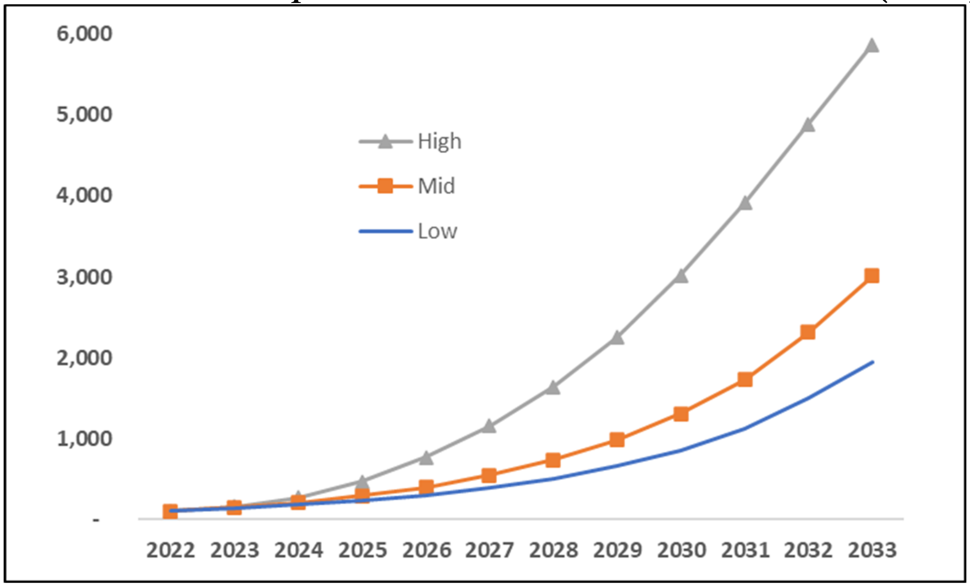


Figure A1 - 15: EV Consumption – NSP Minnesota Service Area (GWh)



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.

8. *Impacts of the IRA on Forecasting*

The passing and signing of the IRA into law provides opportunities for utilities to capitalize on incentives for the development of renewable energy resources. The Company is continuously exploring these options and evaluating how they may impact our plans for our system. Specifically, in relation to our distribution system, we have incorporated incentives offered by the IRA into our forecasted adoption rates for EVs and solar.[17]

Overall, the extension of the tax credit increased the expected EV adoption scenario in 2030 by approximately 20 percent and the expected solar adoption forecast in 2030 by approximately 30 percent.

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[17] Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G999/CI-22-624 states in part, "The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how […] the Act has impacted planning assumptions including (but not limited to) […] the adoption rates of electric vehicles, distributed energy resources, and other electrification measures."

a. Electric Vehicles

We have accounted for two impacts of the IRA in our EV forecast models: (1) the extension of the $7,500 federal tax credit through 2032, and (2) limited eligibility for the tax credit for the next three years, due to critical material and domestic assembly requirements. We are exploring how to incorporate other aspects of the IRA into future forecasts.

b. Solar

The IRA extended the investment tax credit (ITC) for rooftop solar beyond 2030. The credit remains at 30 percent through 2032, then declines to 26 percent in 2033, and to 22 percent in 2034. We included these declining rates in the forecast to incorporate significant changes as a result of the IRA. The forecast prior to IRA enactment included a 22 percent ITC through 2032 with no further tax credits beyond that year.

We have also accounted for the tax credits available to utility-scale solar projects if (1) the materials they utilize are made in the U.S., and (2) the project is built in an energy community (for example, a community with a retiring coal plant).

C. Distribution Planning – LoadSEER DER Forecast Scenarios

IDP Requirement 3.C.1 requires, in part:

> *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.*

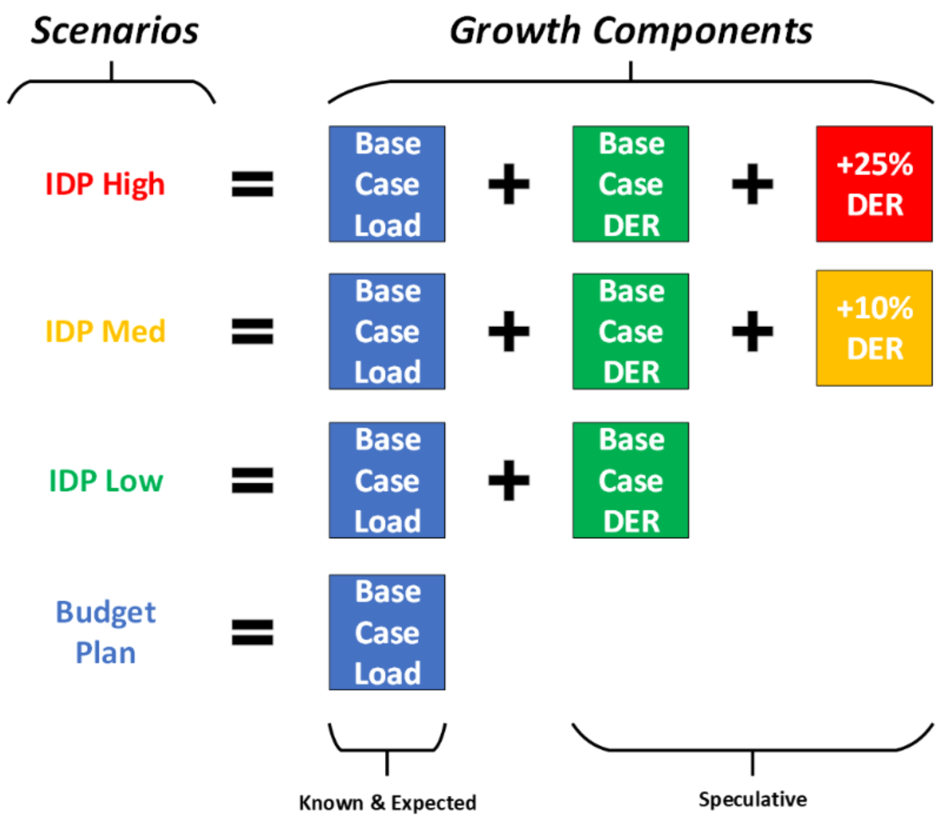
In response to the fundamental changes occurring on the distribution system, we recognized a need and sought a new tool to aid in developing a load forecast and distribution plans that would allow for enhanced analysis. Increasing penetrations of DER on the distribution system require Distribution Planning 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. This IDP represents a milestone in that we are presenting our DER forecast scenarios from LoadSEER for the first time.

The above sections discussed the development of DER forecast scenarios at the corporate- or state-wide level. However, adoption of DER on the distribution system is location-specific, and adoption impacts are unique to each individual feeder. To better understand the potential location-specific impacts of the DER forecast scenarios on the distribution system, the forecasts were then allocated to the distribution system using LoadSEER. The scenarios that were created and then analyzed in LoadSEER comprise various combinations of the corporate-level DER adoption forecasts.

The "Budget Plan" scenario represents the distribution load forecast when only the corporate energy sales and demand forecast is included and is the forecast that is primarily used for planning projects in the Distribution five-year capital budget. The Budget Plan scenario is used for planning projects because it only contains load growth that is considered "known and expected" based on actual applications to add load that have been received, as well as known trends for new customer interconnections; this represents the minimum desired funding level for capacity work to meet immediate distribution system capacity needs. Three DER scenarios were then built off of the Budget Plan by adding varying levels of speculative DER adoption based on the corporate-level DER adoption forecasts. The distinction between each scenario is shown in Figure A1-16 below.

Figure A1 - 16: Scenario Definitions



To align with the intent of IDP Requirement 3.C.1, the "IDP Low" scenario represents what is considered the base case, or expected adoption forecast for each DER technology forecasted. The "IDP Med" and "IDP High" scenarios then represent faster-than-expected adoption scenarios for each DER technology, adding an extra 10 percent and an extra 25 percent of DER adoption over the base case, respectively.

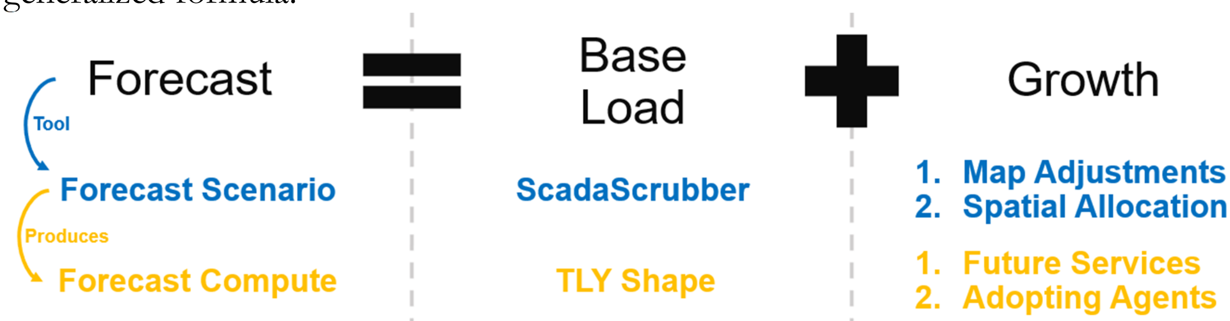
In the following sections, we describe the methodology and corporate forecast allocations that were used for each growth component to create the LoadSEER forecast scenarios.

Attachment M provides the tabular forecast data for the charts below in live Excel format.

1. *LoadSEER Forecasting Methodology*

LoadSEER is a spatial load forecasting tool that is used by electric distribution system planners to predict how much power must be delivered, where on the grid the power is needed, and when it must be supplied. It integrates geospatial data, system and customer level data, historical and forecasted weather patterns, as well as distribution load flow application data to produce a forecast.

The methodology behind how a forecast is assembled can be illustrated by a generalized formula:

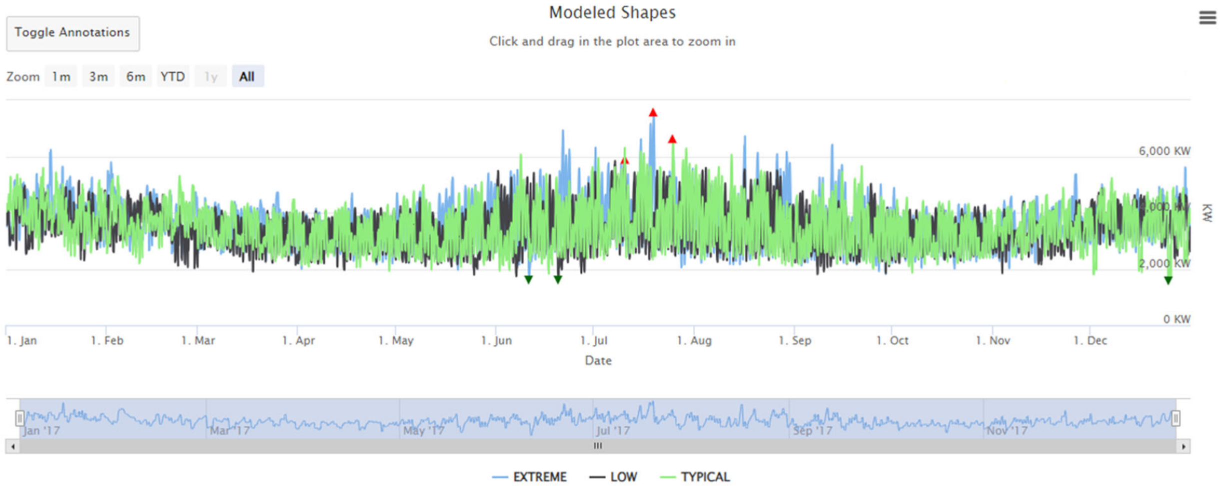


The forecast consists of two main components, which involve constructing a base load and then adding a growth propensity.

The base load is compiled using a LoadSEER tool called ScadaScrubber. The primary function of this tool is to develop Typical Load Year (TLY) shapes, which represent the load on the circuit today under different weather scenarios. The TLYs are 8,760 shapes, meaning that they represent the hourly loading on the feeder throughout a full year.

Users of ScadaScrubber have the capability to clean historical SCADA data, which eliminates any operational switching impacts as well as any other data abnormalities. ScadaScrubber also load- and weather-normalizes the SCADA data before re-simulating it against a low, typical, and extreme weather scenario to produce the TLY shape. It does this by assembling 30 years of hourly historical weather datasets that are available at the weather station closest to the feeder or substation transformer being analyzed. Once a TLY has been produced, as shown below in Figure A1-17, it then can be imported into LoadSEER for inclusion in a load forecast.

Figure A1 - 17: TLY Shape Example in LoadSEER



Once a TLY has been created to represent the base load, load growth in the forecast is then accounted for via map adjustments and spatial allocation.

Map adjustments are primarily used to represent known load growth in the load forecast. When a customer applies to interconnect load to our distribution system or requests a capacity check, a map adjustment can be used to account for that added load at the corresponding geographic location in the LoadSEER model. When a map adjustment is added, a load shape that represents the expected hourly demand of that customer is also identified in LoadSEER. This is helpful for distribution planning because the customer's peak demand is not always coincident with the feeder or substation transformer peak demand, so using load shapes for map adjustments enables a more accurate capacity check process then was possible prior to the LoadSEER implementation.

Map adjustments can also be used to flag areas where the Company anticipates there to be higher levels of adoption of a particular technology. For example, if a strip mall has reached out to the Company to inquire about adding EV chargers at their parking lot but is not ready to install for several more years, a map adjustment for the potential of that load addition can still be added. But, rather than "locking" the map adjustment, which effectively guarantees that the load will be included in the forecast, it would instead have a representative probability of adoption that is fed as an input into the Spatial Allocation. These conceptual future potential map adjustments can assist in increasing the accuracy of the forecast by focusing the load growth to geographic areas with a higher propensity of adoption of a particular technology.

Whereas map adjustments are manually added to the LoadSEER model by the Company, Spatial Allocation is generally done in collaboration with Integral Analytics, the developer of LoadSEER. Spatial Allocation is a significantly more intelligent and automated approach to simulating load growth across the distribution system than map adjustments. However, having both map adjustments and Spatial Allocation work in conjunction with each other significantly increases forecast accuracy, so both are necessary.

The concept of Spatial Allocation can be summarized into a generalized formula:

Spatial Allocation = Future Potential Adoption Points + Shapes + Forecasts

The key function of Spatial Allocation is to simulate load growth across the system via a probabilistic model for agent adoption that determines likely innovators and imitators. It takes a forecast that is typically at a high-level node in the asset hierarchy, like state or operating company, and then disaggregates that forecast intelligently to existing and future customers at specific locations on the distribution system. The Company provides LoadSEER with a forecast and shape for a particular technology as inputs for the Spatial Allocation. The Company then collaborates with Integral Analytics to identify future potential adoption points relevant to the forecast supplied. During this process, the goal is to guide Integral Analytics to indicate which data services to target, supply any relevant external data sets, and supply internal information regarding high adoption areas.

Shapes in LoadSEER provide an hourly estimation of customer loads for a particular technology or customer type. These shapes are developed using both internal data sets and industry collaborations with institutions, such as NREL and EPRI. As AMI data availability proliferates, the Company anticipates that these shapes will improve in accuracy. These shapes are used in LoadSEER for map adjustments, Spatial Allocation, and the forecast as a whole.

Growth can come from a variety of different factors, including new customers being interconnected with the distribution system, changes in customer usage patterns, and the adoption of different DER technologies such as solar PV, electric vehicles, and more. To address this, each type of growth is allocated in a unique run of the Spatial Allocation that is designed to target and model the adoption of that specific type of growth or technology. To compute a load forecast, Distribution Planners can select any individual or combination of Spatial Allocation runs to add to the base load TLY shapes. This allows the Company to either isolate a particular growth factor to understand how it is individually affecting distribution system loading or merge multiple growth factors together to see the aggregate net impact that a variety of technologies will have in the long term.

2. Expected DER Output and Generation Profiles

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

> *…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.).*

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 NREL's PVWatts 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.[18] In the future, we anticipate that additional capabilities from AMI meters will be the primary source of data used for load research load profiles.

3. Corporate-Level Forecasts in LoadSEER Spatial Allocation

IDP Requirement 3.C.1 requires, in part:

> *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.

[18] The Company's 2024-2026 ECO Triennial shows the energy efficiency and incremental demand response targets including load shape information.

The following section addresses how corporate-level forecasts are modeled in the LoadSEER Spatial Allocation; the corporate forecast methodologies are discussed in Section II.B above. Each allocated forecast has unique characteristics to consider when implementing in a load forecast in LoadSEER. The forecasts that are currently allocated in LoadSEER are the corporate energy sales and demand, electric vehicle, solar PV, battery storage, and beneficial electrification forecasts.

The corporate energy sales and demand forecast is received as annual peak demand for the state of Minnesota. The change in peak demand year-over-year is then allocated as growth in LoadSEER. For example, if the peak demand for the state of Minnesota is anticipated to increase by 20 MW from one year to the next, then the spatial allocation for that year will disaggregate the 20 MW and find locations on the distribution system to add that growth. This forecast currently is not broken out by customer type, so flat shapes are utilized instead of individual customer shapes.

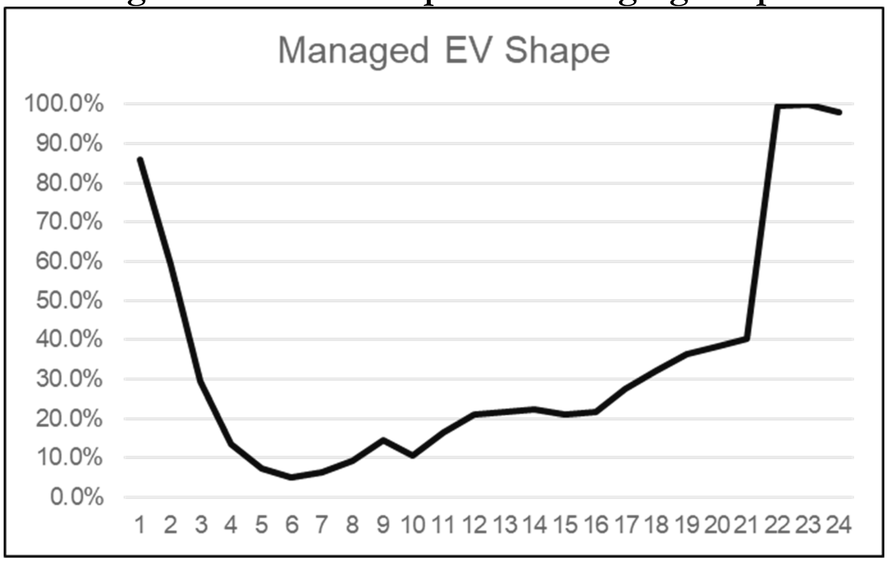
In the 2022 forecast, the corporate energy sales and demand forecast used already includes the forecasted impact of energy efficiency and demand response. The Company anticipates that future forecasts will have these energy efficiency and demand side management layers separated out to enable more granular forecasting.

The EV forecast allocation in LoadSEER can be generalized into the following formula:

EV Forecast = Quantity of EV's + EV Shape + EV Shape Magnitude + EV Future Potential Adoption Points

EV forecasts are received in terms of the quantity of EVs and not the demand in kW. Therefore, some additional steps are required to identify demand impacts to the forecast. The EV forecast data available splits out the forecast into LDV, MDV, and HDV. The LDV category is further subdivided into residential, workplace, and public charging. To identify the demand impacts of the quantity of EVs, an EV charging shape is applied. Figure A1-18 below shows a representative EV charging shape over time (x axis), normalized to percentage of charging kW capacity (y axis).

Figure A1 - 18: Example EV Charging Shape



Within LoadSEER, a kW peak is identified for each shape type and applied to each forecast component (LDV, MDV, HDV). Future potential adoption points are then identified and loaded into the LoadSEER model in collaboration with Integral Analytics. These points identify where in the system we anticipate there to be EV adoption, how much adoption, and what type of EV adoption.

The solar forecast is split into rooftop PV and Front of the Meter (FTM). The FTM solar forecast includes CSGs, as well as the anticipated solar that will be interconnected to the Company's distribution system to meet the new three percent distributed solar energy standard (DSES).[19] Each element has distinct considerations in the forecast. Whereas the rooftop PV forecast can use existing customer locations as potential adopting points in the Spatial Allocation, the FTM forecast requires future adoption points that consider land availability. There are also slightly different shapes used for rooftop PV and CSGs due to the difference in the daily output.

The Company is still exploring the best ways to implement beneficial electrification (BE) and battery storage forecasting allocations in LoadSEER. For both, accurate shapes and data availability is limited in capability due to the technology being emerging and because adoption is currently low. Nonetheless, we did run allocations for both BE and battery storage in LoadSEER with load and charging shapes that represent our best available estimates at this time. It should also be noted that BE

[19] Minn. Stat. § 216B.1691 subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16, which requires three percent of the Company's total retail electric sales in Minnesota to be generated from new qualifying solar energy generating systems by the end of 2030.

forecasts are currently only available for residential customers in Minnesota. Commercial and industrial BE forecasts are still under development. Battery storage forecasts currently only reflect behind-the-meter adoption. For both BE and battery storage, we anticipate spatial forecast refinement to evolve quickly over the next few years.

Once all TLY base load shapes, Spatial Allocations, and map adjustments have been developed, they are all merged into a grouping called a scenario. Scenarios in LoadSEER allow a user to run sensitivity studies on different forecast components. For example, if desired, a user can see the impacts of increasing the impact of a particular spatial allocation and decreasing a different one.

This IDP represents the first time we have used LoadSEER for our forecast scenarios, an exciting and important step in the evolution of our planning process and the IDP. Table A1-10 below describes the corporate-level DER scenarios that were used to create each of the three LoadSEER scenarios.

Table A1 - 10: Corporate-Level DER Scenarios Used in LoadSEER Scenario Forecasts

Budget Plan	IDP Low	IDP Med	IDP High
Corp Demand	Corp Demand	Corp Demand	Corp Demand
	EV: Mid	EV: Mid +10%	EV: Mid +25%
	BE: Base/125%	BE: Base/110%	BE: Base
	Solar FTM: Low	Solar FTM: Medium	Solar FTM: High (Legislation)
	Solar Rooftop: Medium	Solar Rooftop: Medium +10%	Solar Rooftop: Medium +25%
	Battery: Mid	Battery: Mid +10%	Battery: Mid +25%

Once the scenarios are configured as desired, a load forecast can then be computed. To compute a load forecast, LoadSEER adds the load growth from all the selected Spatial Allocations and map adjustments to the TLY base load shapes for each affected feeder and substation transformer. This then creates an 8,760-hour representation of the feeder and bank loading for each year of the 30-year forecast. Figure A1-19 shows an example of this forecast data, summarized to an annual peak load value.

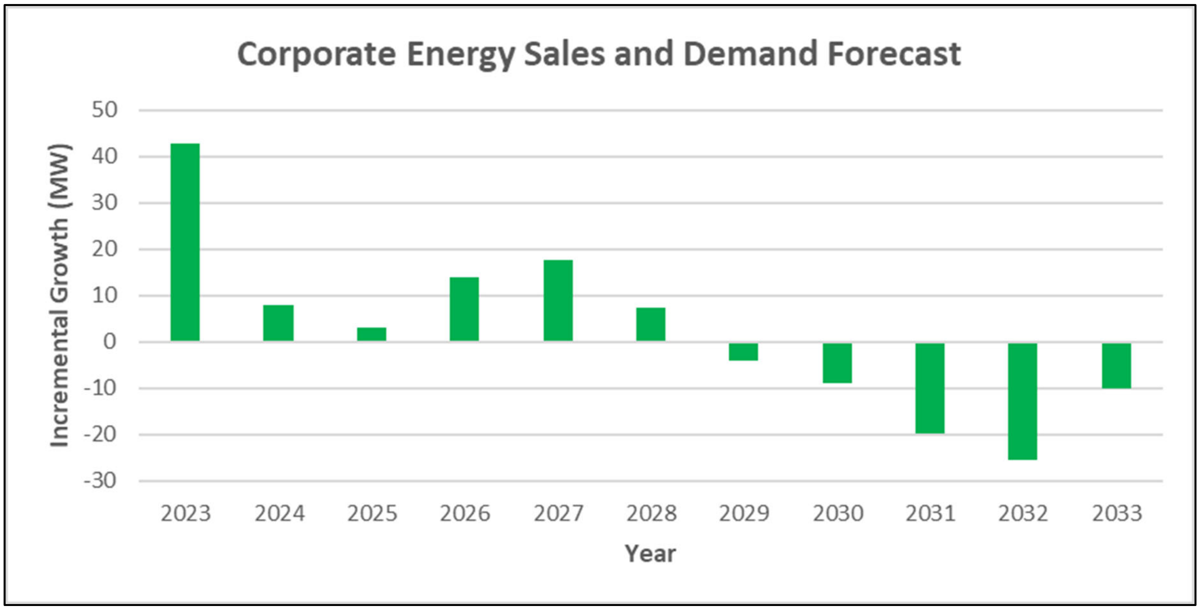
Figure A1 - 19: Example of Node-Level Forecast Data Shown in LoadSEER

Node Name	NodeID	2024 Peak Load	2025 Peak Load	2026 Peak Load	2027 Peak Load	2028 Peak Load	2029 Peak Load	2030 Peak Load
Substation 1	SUB1	118552	121987	125513	129268	133782	138336	144282
SUB1_13.8 kV	SUB1_13.8 kV	118552	121987	125513	129268	133782	138336	144282
Substation 1 115/13.8 kV TR2	SUB1_TR2	24701	25349	25785	26447	27314	27816	29022
Substation 1 115/13.8 kV TR3	SUB1_TR3	58373	60542	62653	64531	66850	69243	72038
Substation 1 115/13.8 kV TR4	SUB1_TR4	49646	50518	51770	53267	54938	56881	58920
Substation 1 115/13.8 kV FDR071	FDR071	0	0	0	0	0	0	0
Substation 1 115/13.8 kV FDR072	FDR072	8942	9034	9287	9768	9993	10159	10451
Substation 1 115/13.8 kV FDR073	FDR073	6657	6657	6660	6660	6661	6661	6781
Substation 1 115/13.8 kV FDR074	FDR074	0	0	0	0	0	0	0
Substation 1 115/13.8 kV FDR075	FDR075	5068	5070	5071	5072	5141	5142	5142
Substation 1 115/13.8 kV FDR076	FDR076	9484	10038	10217	10398	10962	11297	12100
Substation 1 115/13.8 kV FDR081	FDR081	3024	3027	3106	3187	3500	3504	3740
Substation 1 115/13.8 kV FDR082	FDR082	7881	7900	8080	8437	8871	9137	9406
Substation 1 115/13.8 kV FDR083	FDR083	8710	9268	9511	9696	10101	10892	11367
Substation 1 115/13.8 kV FDR084	FDR084	7151	7704	8528	8950	9594	10002	11045
Substation 1 115/13.8 kV FDR085	FDR085	9970	10328	10497	10747	11010	11321	11802
Substation 1 115/13.8 kV FDR086	FDR086	11523	11663	11861	12026	12125	12350	12447
Substation 1 115/13.8 kV FDR087	FDR087	4953	5169	5191	5343	5364	5448	5467
Substation 1 115/13.8 kV FDR088	FDR088	12791	12954	13196	13359	13456	13704	13805

4. *Corporate Energy Sales and Demand*

As described above, the corporate energy sales and demand forecast is common to all LoadSEER scenarios, including the Budget Plan scenario. To allocate this forecast to the distribution system in LoadSEER, the difference in annual system peak load is calculated year-over-year and that change in peak demand is allocated to the feeders. The corporate demand forecast currently includes the impact of energy efficiency and demand response, so those load-reducing impacts are balanced against anticipated new customer interconnections. This results in a forecast allocation in which some years yield increases in demand, and other years yield decreases. Figure A1-20 shows the incremental growth allocated to the distribution system for each year of the 10-year forecast in LoadSEER.

Figure A1 - 20: Incremental Growth from Corporate Demand Forecast in LoadSEER



5. Electric Vehicles

This filing represents the first time we have used a specific EV forecast within LoadSEER. Due to the relative complexity of modeling the location-specific impacts of EV forecasts on the distribution system compared to other DER types, LoadSEER modeling activities for EVs began early in the forecasting process. The corporate EV forecast was updated in 2023 to include the latest adoption data, but we did not have time to incorporate the new EV forecast in LoadSEER in time for our analysis. However, with this first iteration of EV forecast modeling in LoadSEER complete, we now have a better understanding of the complexity and anticipate that it will be easier to align the vintages for the EV forecast in the future.

For EVs, we used the "Mid" corporate EV adoption scenario for the "IDP Low" scenario in LoadSEER as this represents the base case expected EV adoption rate. We then developed +10% and +25% sensitivities from the "Mid" scenario to create the "IDP Med" and "IDP High" scenarios in LoadSEER, respectively. Separate allocations were created for LDV, MDV, and HDV. For LDV, or passenger vehicles, there are a lot of options for charging that have different demand impacts on the distribution system; for example, charging at a residential location, workplace, or public location all have unique characteristics and expected hourly loading impacts. To account for these distinctions more accurately, the LDV allocation was divided into 85 percent Residential, 5 percent Workplace, and 10 percent Public charging allocations. Within the 85 percent residential component, we used an assumption of 1.8 EVs per residential household. Since LoadSEER considers where the load growth is occurring rather than the quantity of EVs charging, this forecast component was split out further to reflect this. 55.6 percent (1.8 EVs in every one household) of the 85 percent residential component was used for the LDV residential forecast.

The EV forecast allocations that were used in LoadSEER, including the three sub-components of the LDV allocation, are shown in Figures A1-21 through A1-25 below.

Figure A1 - 21: Incremental LDV-Residential Adoption Allocated in LoadSEER

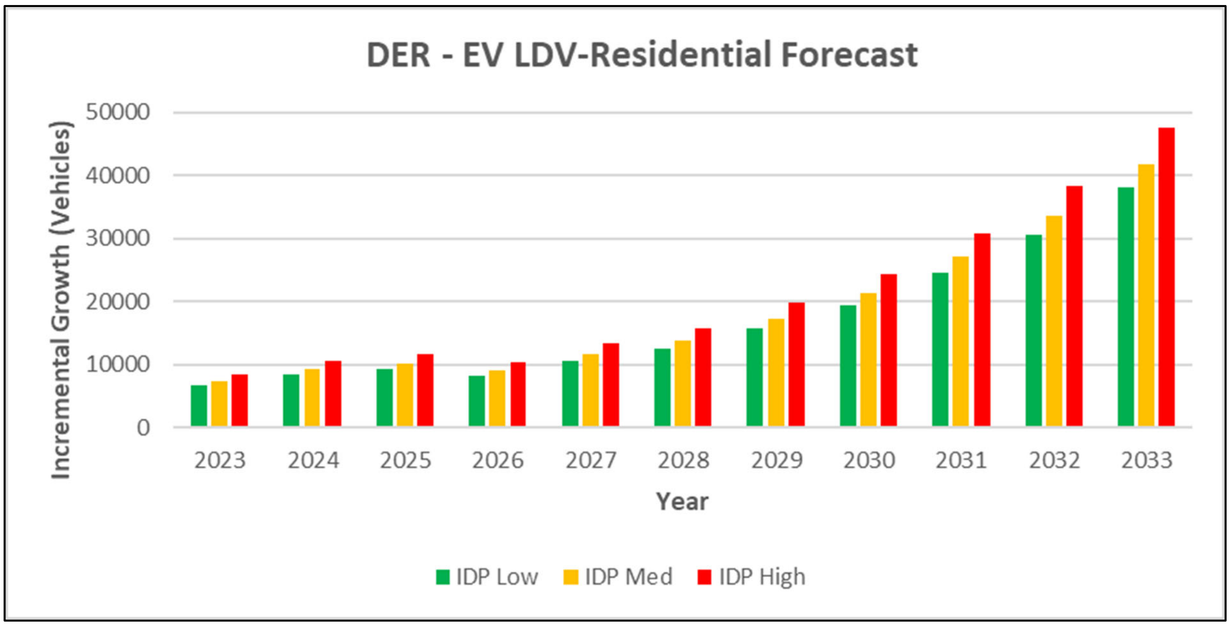


Figure A1 - 22: Incremental LDV-Workplace Adoption Allocated in LoadSEER

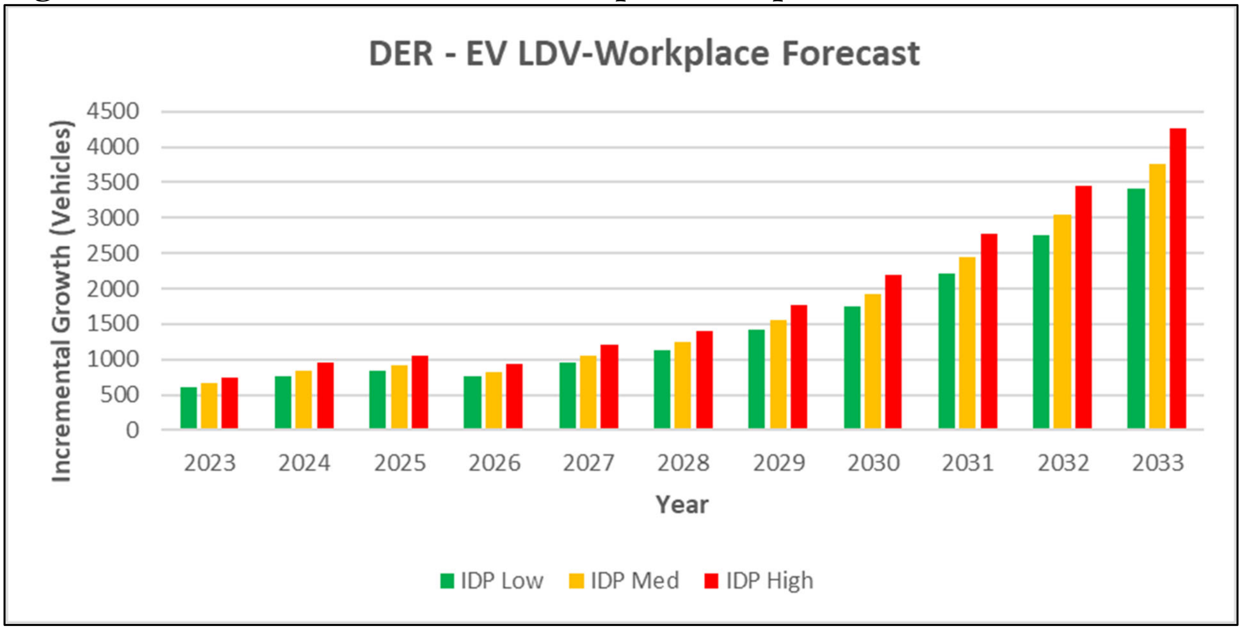


Figure A1 - 23: Incremental LDV-Public Adoption Allocated in LoadSEER

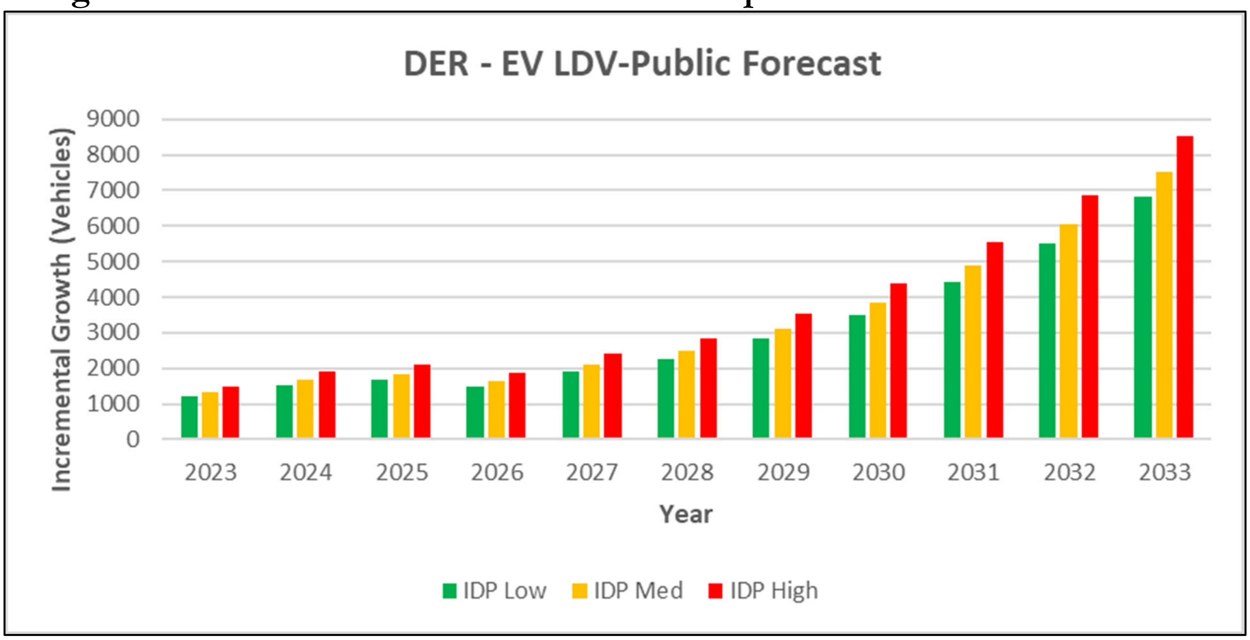


Figure A1 - 24: Incremental MDV Adoption Allocated in LoadSEER

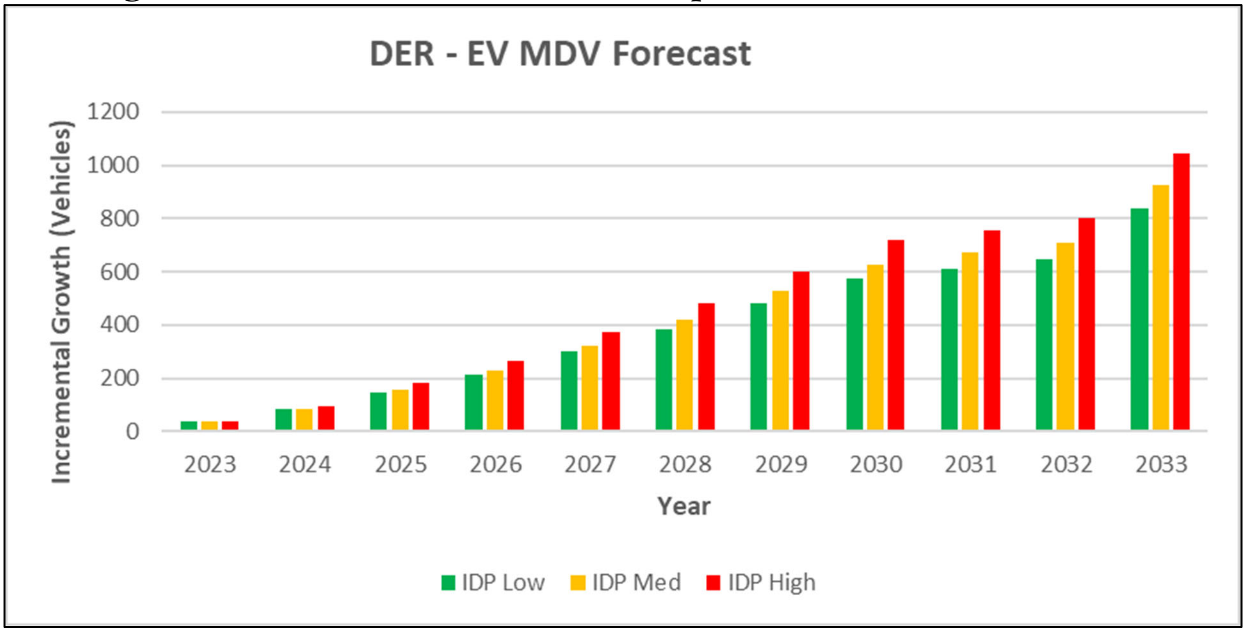
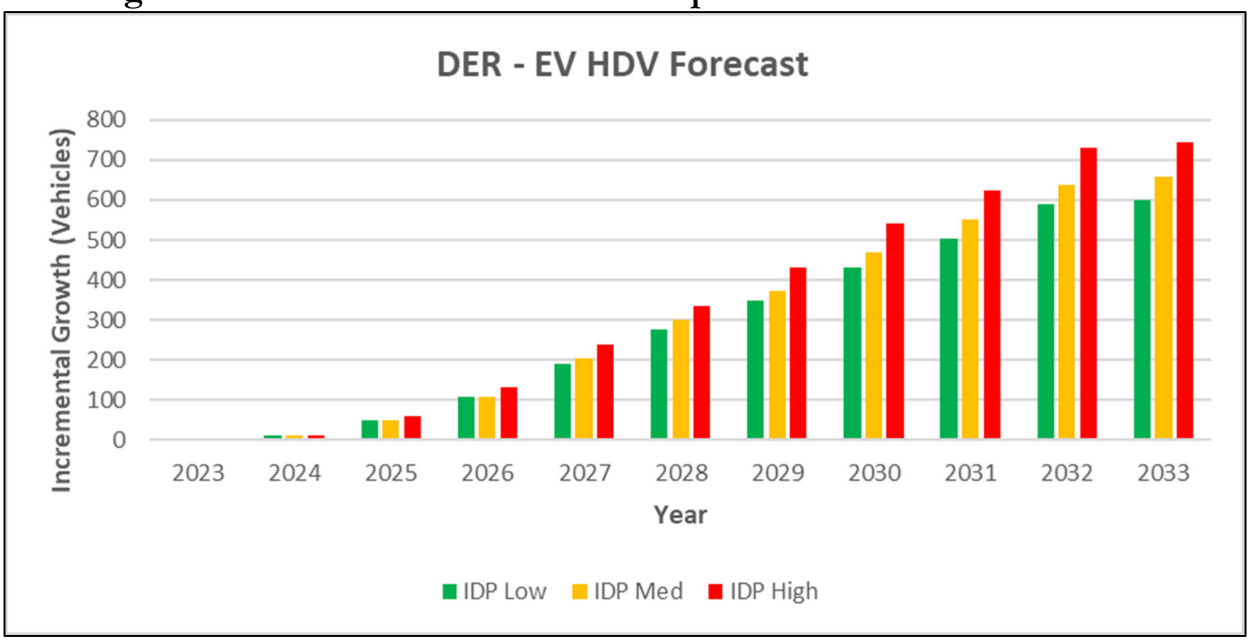


Figure A1 - 25: Incremental HDV Adoption Allocated in LoadSEER

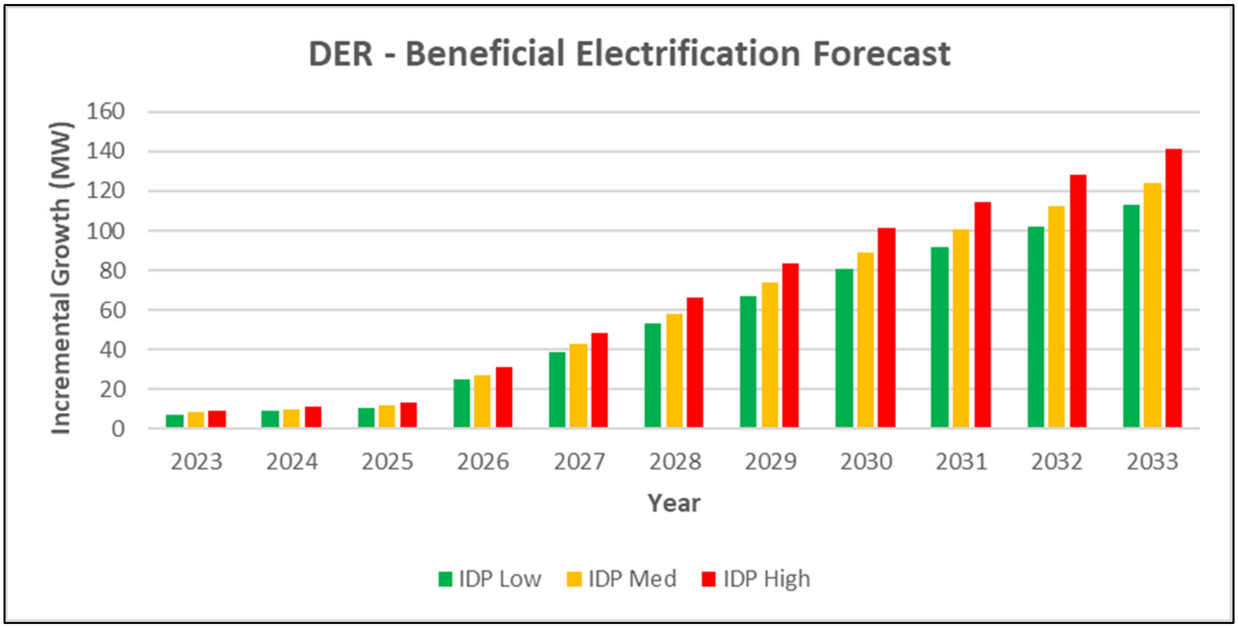


6. *Beneficial Electrification*

The corporate level BE forecast for Minnesota is in its nascent stage and currently only represents residential water heat and residential space heat. Only one representative forecast scenario is available, and it corresponds to a high adoption case. Therefore, to create the LoadSEER allocation, this was used directly for the

"IDP High" scenario, and the "IDP Med" and base case "IDP Low" scenarios were calculated from the high case. The allocation that was used in LoadSEER is shown in Figure A1-26 below.

Figure A1 - 26: Incremental Beneficial Electrification Growth Allocated in LoadSEER



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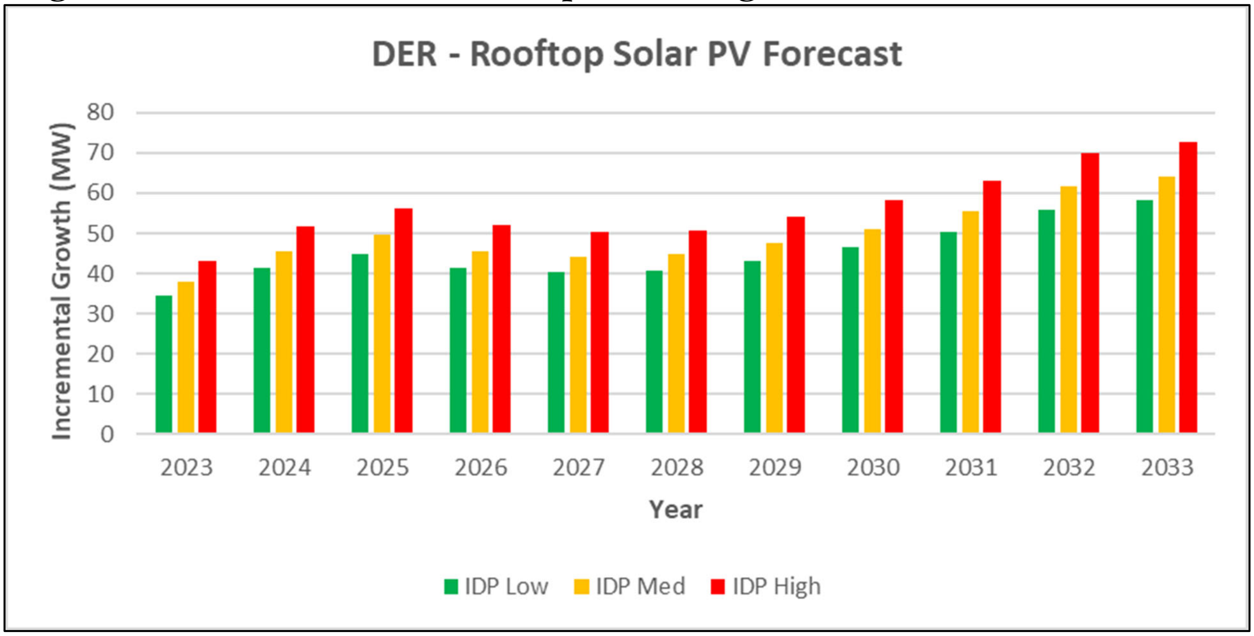
7. *Solar PV*

The Solar PV allocation in LoadSEER was divided into two components: rooftop solar, and FTM solar. For rooftop solar PV, the medium forecast was used for the "IDP Low" scenario and then +10% and +25% were added to create the "IDP Med" and "IDP High" scenarios. This allocation is shown in Figure A1-27 below.

Figure A1 - 27: Incremental Rooftop Solar PV growth Allocated in LoadSEER



The FTM solar PV forecast includes two categories: CSG, and the new three percent DSES established in the 2023 Minnesota legislative session.[20] There is significant overlap in the potential future adoption points (i.e., locations) for both of these categories. Therefore, the two must be combined into one allocation.

We have estimated that the total amount of nameplate solar required to meet the three percent DSES will be around 500 MW of solar. For the purposes of generating a forecast, we made assumptions for the timing of how that solar would interconnect with our distribution system between now and 2030. The 500 MW of solar and those timing assumptions are common across all three LoadSEER DER scenarios, which drives a significant increase in incremental FTM solar in 2026-2029.

For the CSG category of the FTM forecast, this was the only forecast for which we did not use the base, base+10% and base+25% definitions for the low, medium, and high scenarios, respectively. In this case, there was so much change that happened to the CSG program in the 2023 legislation, and it will take time to determine how that will ultimately impact incentives, program administration, and CSG adoption. To better understand the range of possible impacts, the scenarios we used are meant to encapsulate all the possible outcomes from these changes.

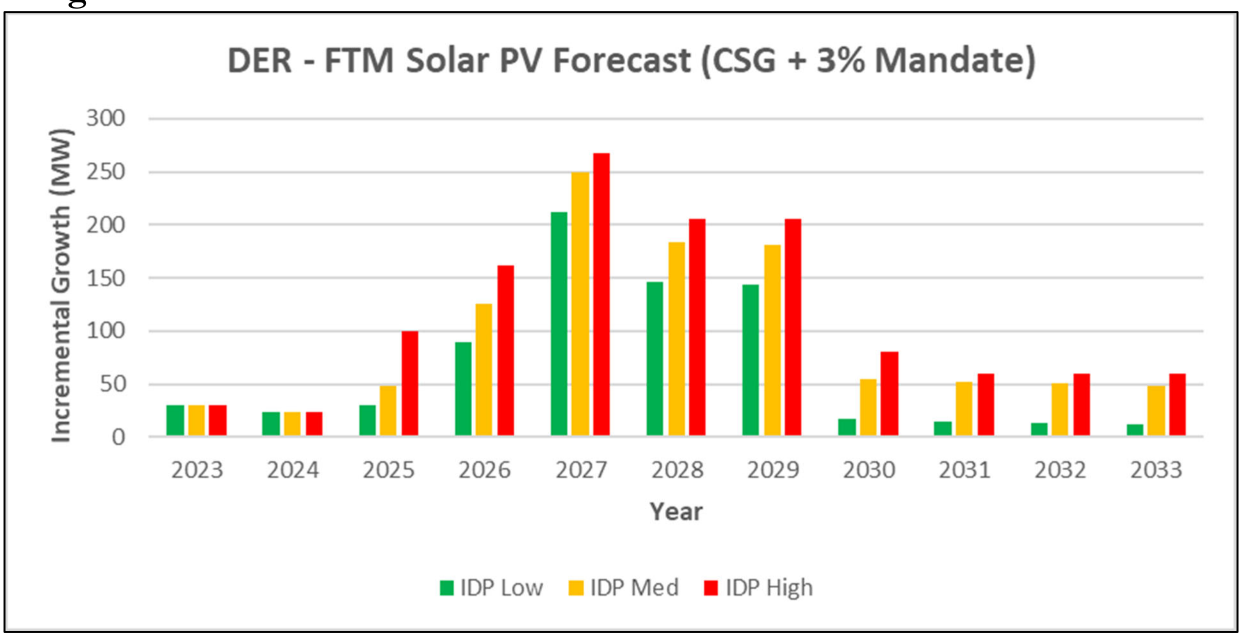
[20] Minn. Stat. § 216B.1691, subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16.

The "IDP Low" scenario assumes that the downward trend we have seen in CSG interconnections will continue into the future. There was an initial wave of CSGs being interconnected in the first few years of the program, but as of the past few years the total MWs of CSG being interconnected each year has come down significantly.

The "IDP High" scenario, however, assumes that the interconnection of CSGs will reach its annual cap every year of the forecast. The cap outlined in the legislation decreases over the coming years, from a max of 100 MW of CSGs per year until 2027, then 80 MW of CSGs per year until 2031, and then 60 MW per year thereafter. This scenario is unconstrained by substation capacity, in part in response to stakeholder feedback that our forecasts should consider unconstrained and constrained scenarios.

The "IDP Med" scenario then takes the "IDP High" scenario and starts to constrain it by available substation capacity. The three LoadSEER allocations for FTM solar PV are shown in Figure A1-28 below.

Figure A1 - 28: Incremental FTM Solar PV Growth Allocated in LoadSEER

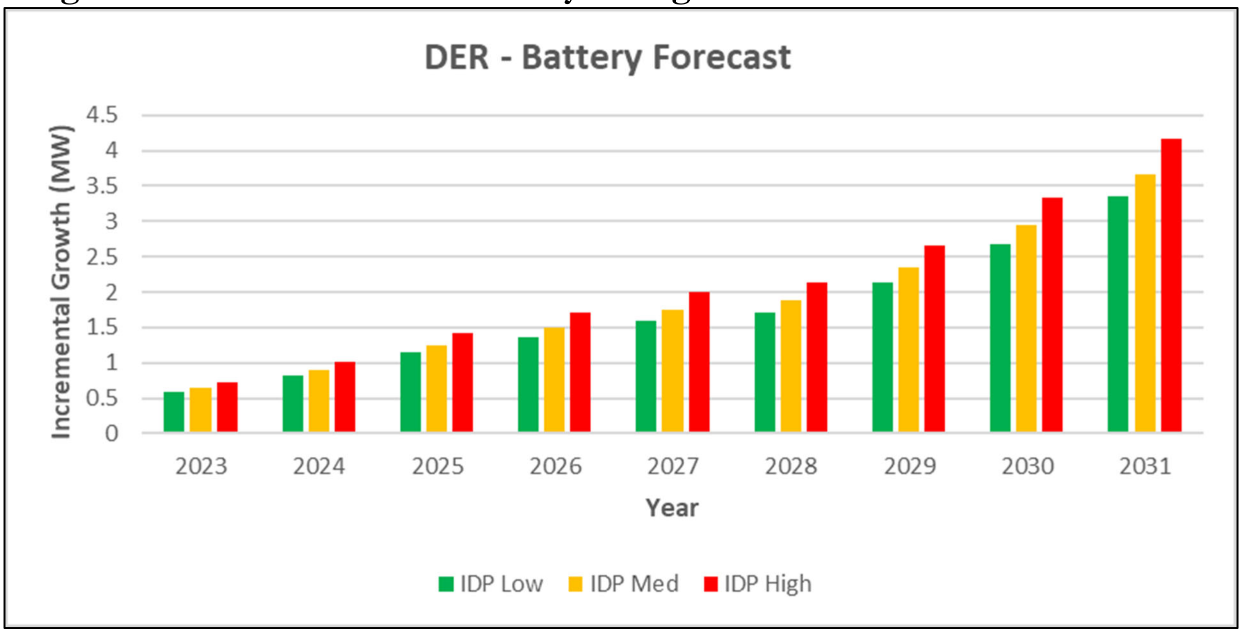


8. Battery Storage

For battery storage, the Mid forecast was used for the "IDP Low" scenario and then +10% and +25% were added to create the "IDP Med" and "IDP High" scenarios. This allocation is shown in Figure A1-29 below.

As noted above, we updated our corporate energy storage forecast in September 2023 – after we had begun our LoadSEER forecasting. Therefore, our LoadSEER forecast scenarios for energy storage are based on the corporate distributed energy storage forecast from the 2021 IDP – the most recent available at the time we needed to begin our analysis. We will incorporate the 2023 forecast into the next iteration of our LoadSEER forecast.

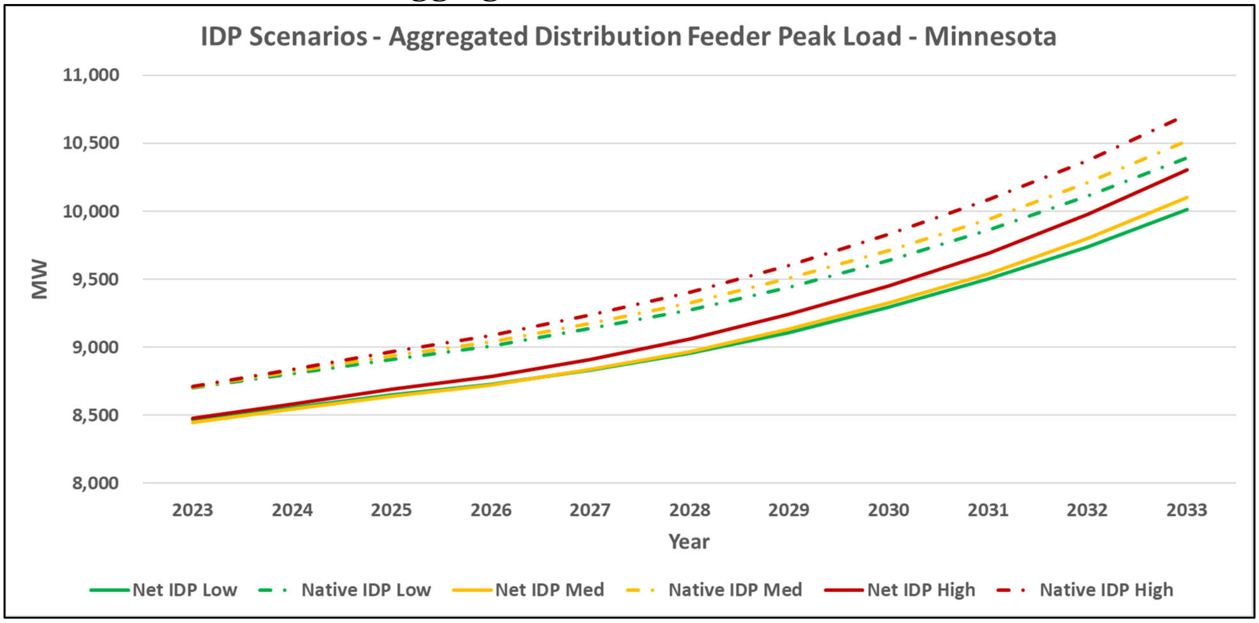
Figure A1 - 29: Incremental Battery Storage Growth Allocated in LoadSEER



9. *Results of LoadSEER Location-Specific Distribution DER Forecast Scenarios*

After the allocations are executed in LoadSEER, the results are combined to compute the forecast for all distribution feeders and substation transformers as discussed in Section II.C above. By aggregating the resulting feeder peak loads in the state of Minnesota for each year, we see the total non-coincident peak demand of the distribution system as shown in Figure A1-30.

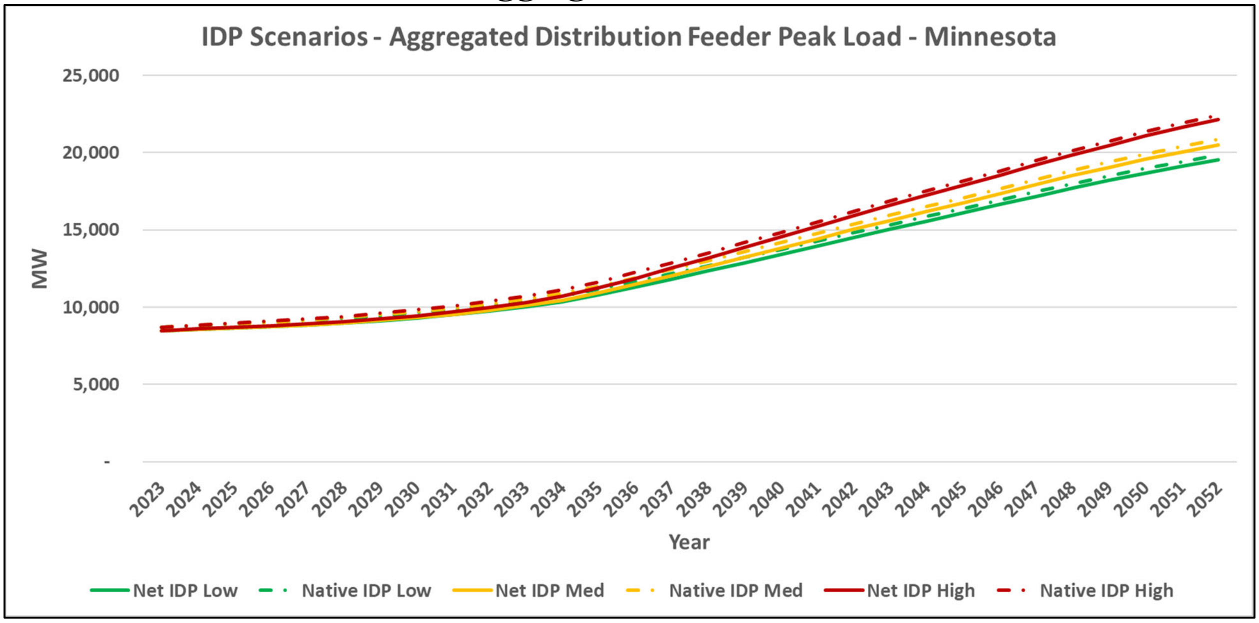
Figure A1 - 30: Total Non-Coincident Distribution Peak Demand Forecast – Aggregated Feeder Peak Load



Overall, the aggregate total of non-coincident feeder peak demands on the distribution system in Minnesota is expected to increase from around 8.5 GW today to over 10.5 GW by 2033. Both the net and native load for each scenario are also shown in Figure A1-30, where the native load does not include the load-reducing impact of the existing and forecasted generation on the distribution system but the net load does. The difference between the net and native peak load, in aggregate, is only about two percent.

LoadSEER is also capable of producing forecasts up to 30 years into the future. When 30-year DER adoption forecasts are allocated in LoadSEER (following the same methodology as described above), the resulting aggregate non-coincident feeder peak demand forecast can be seen in Figure A1-31.

Figure A1 - 31: Total Non-Coincident Distribution Peak Demand 30-Year Forecast – Aggregated Feeder Peak Load



The 30-year forecast shows all three scenarios increasing from around 8.5 GW today to 20 GW or more by 2052. It also creates perspective, in that the growth from 8.5 GW today to over 10.5 GW by 2033 is only the precursor to a much more rapid rate of growth in the following 20 years.

Another noteworthy observation is that the difference between the net load and native load, in aggregate, decreases slightly over the 30-year forecast. This is because, despite allocating several gigawatts of distributed solar PV during the 30-year forecast, the significant amount of EV and BE load allocated pushes many feeder peaks late into the evening, outside of the hours when solar PV is typically generating.

The LoadSEER forecast results can also be seen summarized by planning division in Attachment M (see "Planning Area Peak Load" tab).

In total, the forecasted impacts on the distribution system are significant and indicate the need to rapidly accelerate the rate of investment in distribution system capacity to be able to meet the needs of our customers over the coming decades. The location-specific forecasting results in LoadSEER do identify substations and feeders where this growth rate is higher or lower, but the upward trend in load-serving need is fairly common across most of the distribution system.

In the coming years, we will continue to refine the assumptions and inputs in our LoadSEER modeling, as well as work to identify the levels of capacity funding that will be needed to meet these needs. We will also continue investigating investments in technologies that may be needed to safely and reliably manage the grid of the future and could be used to reduce the need for traditional capacity upgrades. The impacts of this unprecedented load growth will reach beyond the distribution system, and we will be working collaboratively with our Transmission Planning, Gas Planning, and Resource Planning business groups to further align on forecast assumptions and plans.

10. LoadSEER Forecasting Roadmap

As more iterations of load forecasting are completed in LoadSEER, forecast granularity and robustness improves over time as data and inputs improve. That being said, there are still key challenges and room for growth in the forecasting process. In our roadmap for improvements, the following main items have been identified.

- **Improving data integrity**, which is key to ensuring an accurate forecast. Higher granularity shapes and forecasting layers, as well as more accurate TLY creation, are essential to improving data integrity.
- **Improving the planning process via AMI data and automation enhancements**. Additional utilization of 8,760 data in the planning process as well as in applications such as the NWA analysis are also areas for improvement.
- **Continued collaboration with Integral Analytics** for developing enhancements in LoadSEER will help improve the forecast. We are collaborating to refine identification of future potential points and enhance LoadSEER to retain historical scenarios.

D. Community-Based Climate Goals

IDP Requirement 3.C.1 regarding DER scenario analysis requires, in part:

> *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.*

In addition to IDP Requirement 3.C.1, the Commission's Order regarding our 2021 IDP required a stakeholder series that, among other things, covered the topic of how the Company should consider and incorporate local clean energy goals into our planning process.

An increasing number of Minnesota communities served by the Company 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 incorporating goals for EV adoption or other forms of beneficial electrification and building efficiency into their plans or as elements of broader sustainability or Climate Action 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 jurisdictional boundaries).

In response to stakeholder and Commission feedback on our 2021 IDP and our most recent IRP, in early 2023, we conducted a survey of the local jurisdictions we serve. Our community relations managers sent the survey via email to 415 cities, townships, and counties. The goal of the survey was to gather complete, detailed information on our communities' goals and specific plans so that we could aggregate and analyze the data compared to our forecasts and scenarios. This was necessary not only to attempt to gather a complete picture and holistic representation of our communities' goals but also because each community's goal may, for example, use a different baseline year, count different types of technology or buildings differently toward a discrete goal, or have different geographic requirements or carbon accounting approaches.

We received 107 responses to the survey, 32 of which indicated that their community had a clean energy-related plan or goal; however, eight of those respondents did not identify the community or did not provide details on the plan. In some cases, we supplemented the information provided by the survey respondent by reviewing the community's plan document(s) or website. We also reviewed the information provided by the Cities of Edina, Richfield, Saint Paul, and St. Louis Park in their April 11, 2022 Letter in our 2021 IDP docket, in which they provided a helpful summary table of Minnesota communities' carbon and clean energy goals.[21] Another source of data is the Company's Partners in Energy (PiE) program, which supports municipalities by helping them develop and implement energy plans – first assisting in developing a plan, then providing 18 months of assistance with plan implementation. These plans often include goals to increase renewable generation and reduce emissions.

Attachment K summarizes the community goals of the communities:

- That responded to the survey and identified themselves;
- For which we were able to find goal or plan information online;
- Identified in the April 11, 2022 Letter from the Cities of Edina, Richfield, Saint Paul, and St. Louis Park; and/or
- That participate in the PiE program.

As stated above, the goal of our survey was to gather enough detailed information from our communities so that we could compare their goals to our forecasts and plans and potentially model the goals. However, in most cases, we were not able to gather sufficient data at a level of detail required for resource plan modeling purposes. For example, most renewable energy goals did not have associated energy (kWh) requirements. In addition, we understand that some communities may set goals that are intentionally aspirational. Others may be speculative or evolving, without supportive policies, feedback loops, or specific implementation plans in place. These factors create challenges when it comes to system modeling. That said, we believe our decarbonization and clean energy plans as a whole will meet or exceed most communities' goals, which we will discuss further in our forthcoming resource plan.

From a distribution system planning and forecasting perspective, incorporating community energy goals directly into LoadSEER is challenging. LoadSEER's spatial allocation functionality is based on the distribution system hierarchy at the node level. This hierarchy does not conform to local jurisdictional boundaries; that is, substations, transformers, and feeders may serve customers in multiple cities. Therefore, modification work needs to be done with the vendor. To the extent a community has specific sites identified for a DER or electrification project, in the future, that information could be manually added to LoadSEER as a "speculative growth point." As our distribution forecasting capabilities continue to grow, we will be able to reflect community goals in our modeling. That said, with respect to the

[21] *See* Appendix A of the Cities' April 11, 2022 Letter in Docket No. E002/M-21-694, at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D0661A80-0000-C61C-BA5B-9ED57809F58A}&documentTitle=20224-184624-01.

DER forecast specifically, we believe the "high" DER forecast scenarios would meet community goals in aggregate.

We are supportive of our communities' goals and aim to help them achieve their goals whenever possible. We encourage our communities to reach out to their community relations manager to discuss their objectives and ways we may be able to help. We also have an obligation to serve all of our customers with reliable, safe, affordable electricity. We serve 415 cities, townships, and counties across Minnesota, and our integrated Upper Midwest system provides electricity to customers and communities across five states. Some customers and communities may have different priorities; indeed, most communities responding to our survey indicated that they did *not* have clean energy-related plans or goals. We cannot forgo responsible system planning and investments that ensure safe, reliable, affordable electricity for all, to favor individual communities' or jurisdictions' energy goals – some of which may be intentionally aspirational – at the expense of customers as a whole. That said, we are always eager to work with our customers and communities to find ways to help them meet their energy goals while minimizing cross-subsidization.

III. RISK ANALYSIS

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

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 FDR001 means that the peak load on FDR001 exceeds the limit of the feeder's limiting element by five 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 FDR001 means that for loss of FDR001, all but 1.5 MVA of FDR001'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."

A. Risk Analysis Results

Our 2023 through 2027 annual planning process (initiated in Q4 2022), analyzed forecasted 2024 loads and identified the following total risks across NSP Minnesota

- N-0 normal overloads on 67 feeder circuits (>100% loaded)
- N-0 normal overloads on 13 substation transformers
- N-1 contingency risks on 540 feeder circuits
- N-1 contingency risks on 177 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 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 2023-2027 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 the aging of our system – as well as preparing it for the future. Budgeting to our system need will become increasingly important as the pace of load growth increases and customers expect timely energization. We cannot wait until a customer asks about capacity before investing in system upgrades; we must prepare our system now so that capacity is readily available, and we are able to maintain safe, reliable service at the same time. We discuss how we strike this balance and prioritize projects below.

B. Planned Net Loading – Initial Methodology

As noted in Section II.A and as required by IDP Order Point 6.f, the Company has developed an initial methodology for considering DER impact to peak loads on feeders and substation transformers. The methodology considers two different types of loading seen in the distribution system.

First, native loading is the actual demand when all DER generation impacts are excluded. This loading assumes that we cannot depend on any DER to lower peak demand due to the technology being non-dispatchable. For DER impacts to be considered, the technology should be available when peak conditions appear, which is not always true for DER generation. For feeders and substation transformers with DER generation, this native loading value is calculated via LoadSEER in the load forecast.

Net loading is the actual demand when all DER impacts are included. This loading considers all DER generation. This is the demand seen via SCADA at the substation for feeders and substation transformers with DER. While this value reflects 100 percent of DER generation impacts at that time, this value does not necessarily indicate whether peaks could be reliably lowered when necessary due to most DERs being non-dispatchable resources.

While 100 percent of DER generation on a given feeder or substation transformer might not reliably and consistently be available to lower peaks, we recognize that there is a certain percentage that can be assumed to be dependable. The amount of DER generation that is available to reduce peak is dependent on a variety of factors. For example, some DER may be offline at the time of peak load due to planned maintenance, equipment damage, or failure. Further, in the case of solar PV, it is a variable, non-dispatchable resource, and it is possible that the amount of incident solar irradiance at the time of peak load may be less than favorable.

The initial methodology to address this involves what we are labeling as Planned Net Loading (PNL) – the calculated demand when a certain percentage of DER generation is assumed to be dependable. For the initial development, only CSG and rooftop PV have been considered.

When planning the grid, we must consider worst-case conditions to account for all outliers and to ensure grid reliability. If PNL is used for planning the grid, the grid becomes dependent on the DER technology to operate as expected during peak conditions. If the DER technology is not available during peak conditions or is available at a lower level than the assumed dependability, grid reliability could deteriorate, and outages can occur.

Additionally, there are operational factors that must be considered in the planning process. Considering DER generation dependability and PNL concepts in relation to how the distribution system is operated during N-0 and N-1 conditions, we see that it is still vital to continue planning components of the grid using both native and net loading.

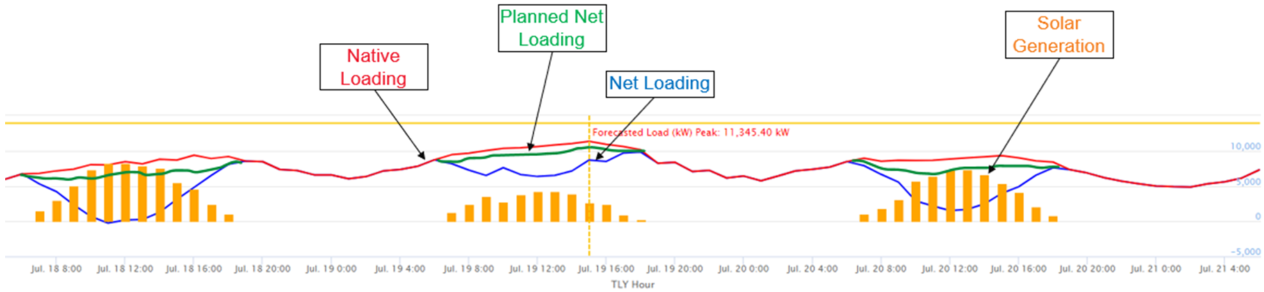
In the case of N-0 normal overloads on a feeder or substation transformer, solar would remain online and Operations would address the overload. In day-to-day operations, the Distribution Control Center uses net loading to identify these overloads, as that is reflected in the real-time SCADA data seen in the control center. In planning for an N-0 in the future, PNL could be utilized, assuming that a certain percentage of DER will be consistently and minimally available in the future.

In the case of a feeder N-1, operationally, solar trips offline on the feeder with the outage – this is necessary to protect the distribution system and also to ensure the safety of our field crews. This feeder would then be studied under native loading conditions due to considerations in safety, delay in restoration of the solar, and abnormal configurations having not been studied during interconnection studies. If the feeder with the outage has a feeder tie to another feeder with solar, that neighboring feeder would keep its solar online and PNL could be utilized.

In the case of a substation transformer N-1, assuming there is a bus tie in the substation, the transformer with the outage would keep solar online as the feeder would remain in its original configuration after the bus tie closes in the substation. Therefore, the transformer would be studied under PNL conditions. If there are no bus ties in the substation, solar would trip offline due to the need for feeder transfers to be conducted.

An example of a peak load curve that considers a certain dependability of DER is shown in Figure A1-32 below.

Figure A1 - 32: Peak Load Curve Considering Solar Dependability



Whereas the net loading represents 100 percent of DER generation impact, the native loading is a calculated value that adds back the load that was masked by the DER generation to reflect loading with 0 percent DER generation impact. The PNL reflects that a certain percentage of DER can be dependable to lower the peak and the PNL loading falls between the native loading and the net loading.

Applying the PNL concepts around DER generation dependability can be summarized into a single formula:

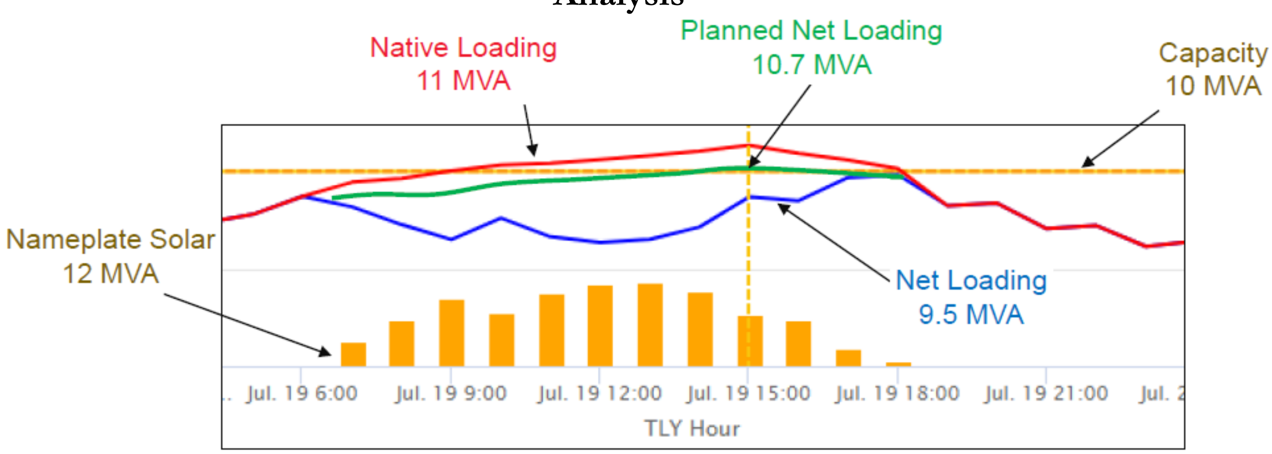
$$Planned\ Loading = Native - [(Native - Net) \times DF_{PV}]$$

Where:

$$DF_{PV} = Dependability\ Factor\ of\ PV$$

Figure A1-33 applies this formula to a N-0 analysis:

Figure A1 - 33: Planned Net Loading Formula Applied to a Feeder N-0 Analysis



In this example, a 15 percent DF_{PV} is used. Keeping in mind that this is 15 percent of the DER generation impact (the difference between native and net load) and not of total nameplate DER generation, the PNL is calculated as such:

$$Planned\ Net\ Loading = 11 - [(11 - 9.5) \times 15\%] = 10.7\ MVA$$

In this case, the PNL of 10.7 MVA is 0.3 MVA lower than the 11 MVA native loading value that would otherwise be used in our current risk analysis process. It is also 1.2 MVA higher than net loading.

Assessing the N-1 risk on the system using PNL is quite like our current N-1 risk methodology, where we study the loss of each feeder and substation transformer and then assess whether the load on the failed equipment can be transferred to neighboring sources without causing equipment overloads. Currently, we check if the native load from the failed equipment can be transferred to neighboring sources by checking the restoring equipment sources' native loading in comparison to its rated capacity. We would apply the PNL methodology to our N-1 risk analysis by still utilizing the native loading on the failed equipment but instead, use the PNL for the equipment that restores service in comparison to its rated capacity. This is due to the fact that the DER generation will trip out of service when the failure occurs, but the DER generation on the restoring feeder will remain in-service.

A 15 percent DF_{PV} would be the most prudent value to use in an initial implementation of the PNL methodology. This assessment was based upon five years (2016-2021) of recorded PV generation as a percentage of nameplate capacity rating from our CSG program in Minnesota, as shown in Table A1-11 below. By taking the average PV output as a percent of nameplate for the specified time frame during each month of the year, we can compare and then select a DF_{PV} that would be safe to use in our PNL methodology. As the selected DF_{PV} can impact how much risk is seen and then considered for mitigations, we must use a conservative estimate to ensure system reliability. Based on the 08:00-18:00 Tracking row of data, we see the actual PV output as low as 12 percent during the month of December, with the next two lowest in January and November; averaging these three lowest months results in a value of 15.04 percent, leading to our initial DF_{PV} of 15 percent.

Table A1 - 11: Average Monthly Solar Generation Output as a Percent of Nameplate Capacity

Time Range	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
00:00-23:59 All Day	7.07%	11.27%	14.26%	15.16%	17.98%	20.23%	20.20%	17.90%	15.39%	11.50%	8.23%	5.40%
08:00-18:00 Tracking	15.44%	24.53%	30.24%	31.13%	36.12%	40.44%	40.93%	36.83%	32.06%	24.35%	17.90%	11.78%
10:00-16:00 Fixed	21.72%	33.09%	38.38%	37.69%	43.10%	47.93%	49.22%	44.93%	39.94%	30.70%	23.26%	16.34%

1. *Risk Analysis Results using PNL*

The following summary tables compare the aggregate quantity and magnitude of feeder and bank overload risks using the native load methodology and the PNL methodology. To better understand the impact of the dependability factor, we also provide the results using both our initial 15 percent DF_{PV} and a slightly higher – and riskier – 25 percent DF_{PV}.

As can be seen in the results, both the 15 percent DF_{PV} and 25 percent DF_{PV} slightly reduce the total quantity and magnitude of N-0 and N-1 risks documented for the distribution system when compared to the native load methodology. While the 25 percent DF_{PV} case does further reduce the documented risk on the distribution system compared to the 15 percent DF_{PV} case, this must be weighed against the increased probability that the DER may not actually provide the impact anticipated by the 25 percent DF_{PV} in real peak load scenarios.

For example, based on the results shown in Tables A1-12 through A1-15 below, using a 15 percent DF_{PV} in the PNL methodology would lead to 64 N-0 feeder risks documented in Distribution Planning's annual risk analysis. However, if a 25 percent DF_{PV} were to be used instead, then it would lead to just 61 N-0 feeder risks documented in the risk analysis. If Distribution Planning started planning the distribution system using a 25 percent DF_{PV} and an actual peak condition were to arise in which the DER did not provide the assumed 25 percent dependable impact, then three additional overloads would be revealed in real time operations that were not identified or planned for mitigation in the planning process.

As described above, based on this analysis, the Company believes that average output data from existing CSGs on the Company's distribution system indicates that 15 percent DF_{PV} would be the safest value to use and minimizes the likelihood that the actual DER impact on peak load could be less than 15 percent dependable in the future.

Table A1 - 12: Feeder Risks and Loading with 15% DF_{PV}

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	8,599,767	8,564,857	34,910
Count of N-0 Risks	67	66	1
Count of N-1 Risks	540	536	4

Table A1 - 13: Feeder Risks and Loading with 25% DF_{PV}

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	8,599,767	8,541,584	58,183
Count of N-0 Risks	67	63	4
Count of N-1 Risks	540	535	5

Table A1 - 14: Bank Risks and Loading with 15% DF_{PV}

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	7,788,144	7,748,657	39,487
Count of N-0 Risks	13	13	0
Count of N-1 Risks	177	177	0

Table A1 - 15: Bank Risks and Loading with 25% DF_{PV}

2024 Values	Native	Planned Net Loading	Difference
Forecasted Demand (kVA)	7,788,144	7,722,333	65,811
Count of N-0 Risks	13	10	3
Count of N-1 Risks	177	177	0

2. Recommendation and Next Steps

To summarize, the initial PNL methodology, if implemented, would replace using native loading for N-0 risk analysis. In the context of N-1 risk analysis, native loading would be used for the failed feeder (assuming solar trips and stays offline) and the restoring feeder would use PNL (assuming solar stays online despite being in an abnormal configuration). In the initial implementation, PNL would begin with a DF_{PV} value of 15 percent. This represents 15 percent of dependable DER generation impact and not the nameplate of generation.

We are open to moving forward with a DF_{PV} value of 15 percent in our N-0 risk analysis; however, it is important for parties and the Commission to understand the drawbacks presented above – i.e., from a policy standpoint, the theoretical benefit of deferring a mitigation investment should be weighed carefully against the possibility of increased system risk and potential impacts to hosting capacity. We are interested in hearing parties' feedback on whether they believe we should implement the DF_{PV} value of 15 percent in our next planning cycle for N-0 risk analysis.

IV. MITIGATION PLANS

After identifying system deficiencies, the next step in the planning process is developing 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. In 2022, Distribution Planning conducted a review of these thresholds, and implemented a change that will help prepare the distribution system for the rate of growth and changes in customer expectations that are expected to occur in the future. For N-0 conditions of transformers, the overload must exceed 100 percent before we develop a project to mitigate the risk; for N-0 conditions of feeders, the loading must exceed 75 percent. For N-1 conditions the load at risk must exceed 0 MVA before we develop a mitigation. This change is a reduction in the thresholds from what have been used historically and will help improve the availability of the distribution system to interconnect new load, such as beneficial electrification or electric vehicles before overloads are experienced. It will also improve our ability to continue reliably serving load under contingency and perform planned work on the distribution system without jeopardizing reliability. The new thresholds are summarized in Table A1-16 below.

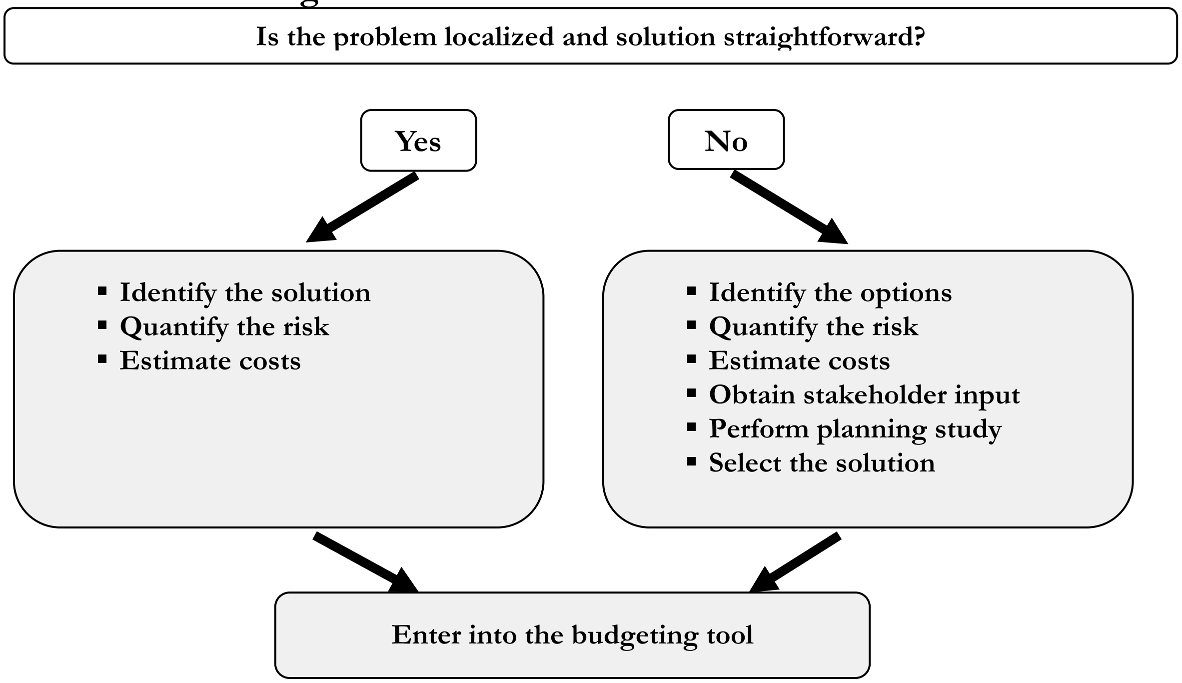
Table A1 - 16: Risk Thresholds Requiring Mitigations

	N-0 Threshold	**N-1 Threshold**
Feeder	15 kV: Loading exceeding 75% 25 and 35 kV: Loading exceeding 50%	Greater than 0 MVA at risk
Substation Transformer	Loading exceeding 100%	Greater than 0 MVA at risk

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 use indicative unit costs.

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

Figure A1 - 34: 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 an NWA. We discuss this analysis in Appendix F.

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.

A. 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 that could affect the proposed plan.
- Generating options.
- Studying and comparing the economics and reliability of the alternatives.

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 the following:

> *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.*

We discuss our NWA analysis that is part of this IDP in Appendix F.

IDP Requirement 3.D.2.o requires:

Long-range distribution studies conducted since the last IDP.

We have not completed any long-term area studies since submitting our last IDP. See Appendix A1 of our 2021 IDP for further discussion of the plan comparison standards and criteria we use in long-range planning studies, when needed.

B. Capacity Risk Project Prioritization

After mitigation projects are identified, 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 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.) and causing an outage.
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.).

V. 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.

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, an Advanced Distribution Management System, and AMI. 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 other compliance obligations and to connect new customers. We note that we must also apply judgment in the prioritization process. A comparatively low-ranking project may still be included in the budget because we consider other factors such as the magnitude, severity, or duration of the risk. Our process therefore contemplates some back-and-forth with the planning engineers to validate priorities.

VI. 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.

This process must be 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 (proactive) may be delayed to accommodate the emergency (reactive). 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 that serves our customers.

Distribution Planning takes the approved capacity projects stemming from this process and communicates them with design and construction teams. The Distribution 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 at least the first two years of approved feeder capacity and asset health projects and the first three years of approved substation capacity and asset health projects; substation projects are released further in advance to account for the impact of long lead time materials such as substation transformers. 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.

VII. DESIGN AND CONSTRUCT

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

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, expansion of 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.

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.

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 substation transformers. It is our goal to able to replace assets closer to their estimated end of useful life while balancing customer costs. 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 Appendix, 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 the Company 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.

Below we provide 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). The Company 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 Institute of Electrical and Electronics Engineers (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 implemented 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 the Company's line crews and Electric Distribution Standards, we updated the Company's 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.

Reclosers with Microprocessor Based Controls (2015-present day). In 2015, Electric Distribution Standards began an evaluation of reclosers. The goal was not only provide for present day capabilities but add the functionality and flexibility to provide solutions in the future. This evaluation resulted in a device that was not reliant on oil or sulfur hexafluoride (SF6), but instead was using independent modules with vacuum bottle interrupters and a microprocessor-based control. The Company was initially able to replace three devices (switch, recloser, sectionalizer) with one device and add different operation behavior (3 phase trip-3 phase lockout, 1 phase trip-3 phase lockout, 1 phase trip-1 phase lockout) with one device. The use of a microprocessor-based control enabled different programs that could be changed depending on the application, which helps "future-proof" the mechanism and the control so it could be modified through software and not require a hardware change. One of the new applications was for serving as a point of interconnection for Community Solar Gardens (CSGs). The programming of the recloser was done to mimic the operation of an inverter built in accordance with IEEE 1584 while providing visibility into the operation of the CSG and a mechanical/electric consistent device controlled by the Company to enable conditions that protect both the line crews working on the distribution system and consistent operation regardless of the condition of the CSG equipment behind the recloser. This has allowed the Company to address some malfunctioning inverter programming, open phase condition, improve visibility into power flows, and reduce device operation and restoration time through remote control. By using a control and mechanism already in use throughout the electric distribution system, this provided a device that was readily available, cost effective though large volume discounts, and familiar to the field crews. The application of the recloser as the point of interconnection device once deployed on the CSG has allowed the Company to minimize the need to take CSGs offline for planned work resulting in greater energy production uptime for the CSGs.

Equipment Standards and Manufacturer Approval (2020-present day). As we discussed in our IDP Annual Update filing in 2022,[1] global supply chain issues have impacted all parts of the nation's economy, including the energy sector. Although many types of electric equipment are affected by supply chain challenges, the most significant impact is in transformer supplies. The Company has experienced shortfalls in transformer supply and worked to mitigate this impact. The Company has a transformer repair shop that was leveraged with Electric Distribution Standards support to save and refurbish transformers. We also reached out to transformer re-manufacturers that would meet the Company's requirements. These transformers were evaluated by Electric Distribution Standards for mechanical and electrical requirements and for safety for our workers and the public. Since 2020, we have approved three additional U.S.-based transformer manufacturers and two South Korean manufacturers. These manufacturers were vetted for their capabilities, technical expertise, quality control, and adherence to Company transformer specification. The review of these transformers involved drawing review, factory assessment, review of the final product, and any necessary corrections. These efforts have provided additional transformer units for the Company to deploy across our service territory.

For additional context, Table A2-1 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 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.

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[1] Docket No. E002/M-21-694 (November 1, 2022).

Table A2-1: 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 Minnesota portion of the NSPM electric distribution system is composed of nearly 24,000 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 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.

Asset Health and Reliability budget categories include new and ongoing projects that we perform each year to address the age and condition of our distribution facilities.

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 the 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. 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. 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 age and composition 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

Typical Vegetation Management helps keep outages to a minimum, reduces the potential for the public to come in contact with electric lines, and helps line crews access the line for maintenance and outage restoration. Specific activities include 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 service interruptions.

2. Arrester Replacement Program

Our arrester replacement program targets arresters 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 arresters is from less than 30 percent of the arrester population. Arrester replacements have been prioritized by specific feeder based on the number of outages in the last five years. Feeders identified by the Feeder Performance Improvement Program are targeted for arrestor replacement where applicable.

3. Low Cost Recloser Program

The low cost recloser program provides us with an economic way to supplement our standard G&W Viper SP recloser. The pilot program concluded at the end of 2021 and the TripSaver II recloser model was approved as standard for company-wide use. Alternate low cost reclosers will continue to be evaluated and explored. A TripSaver II device is a unique single-phase, electronically controlled, cutout mounted recloser unit that can be programmed with time curves allowing it to emulate traditional reclosers or fuses. Low cost reclosers are intended to provide both fuse-saving and fuse-blowing schemes. Application practices were explored in the pilot program identifying installation location in areas with treed taps or extensive exposure or location where existing fuses cause repeated outages.

During the pilot program, approximately 250 TripSaver II reclosers were installed in Colorado, Minnesota, and Wisconsin areas in the 2017/2018 time frame. Thirty-nine of the 250 were installed in Minnesota. Data was collected over a range of 3 to 6 months after installations occurred and reliability results were extrapolated to 12 months. Over the course of the pilot, NSPM experienced 9 TripSaver II lockouts. Reclosers operated as expected and all lockouts were permanent events such as vegetation in line, wire down, or public damage, which indicated that the devices were operating reliably. From June 2018 to January 2019, Minnesota saved 7 truck rolls for an estimated annual savings of 12 truck rolls. TripSaver II devices operated as expected during the pilot program and improved customer reliability in areas installed.

4. Feeder Performance Improvement Program

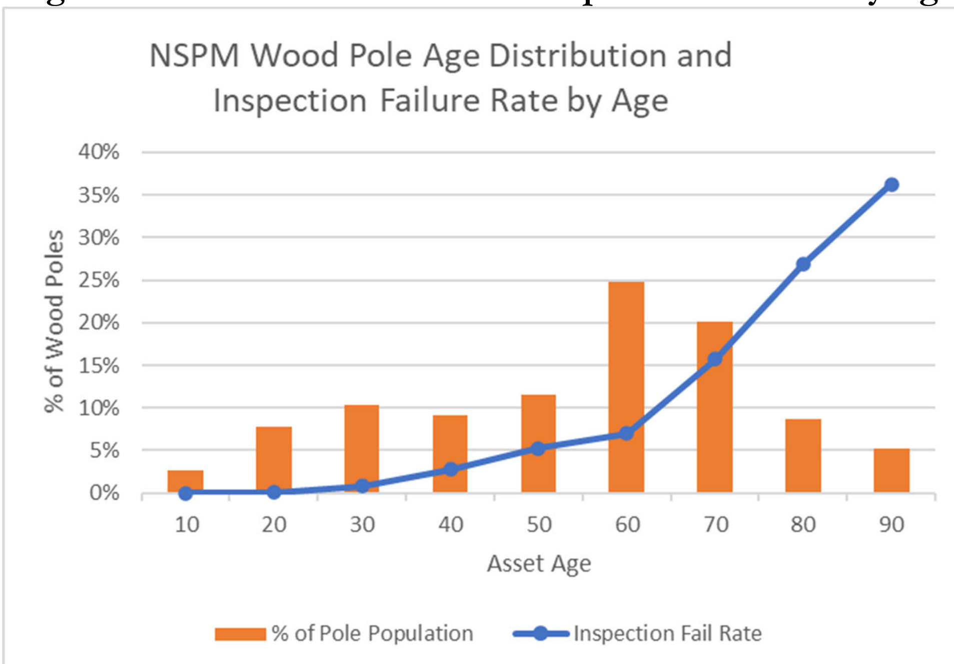
The Feeder Performance Improvement Program (FPIP) is a program to identify locations where there is opportunity to improve the reliability of our electric service. FPIP evaluations are performed at the feeder level because that is the most common distinct level for systematically measuring reliability performance for groups of our customers. The focus is on improvement of the outage performance of the distribution system in order to reduce interruptions to groups of customers. Measures of electric interruptions to customers include frequency and duration of the interruptions. The FPIP only includes feeders with 10 or more customers served. The feeders identified by the FPIP tend to include feeders that also have a significant contribution to the CEMI4 (Customers Experiencing Multiple Interruptions [4+]) customer count. All feeders on the FPIP list are reviewed for corrective action opportunities.

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 A2-1 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.

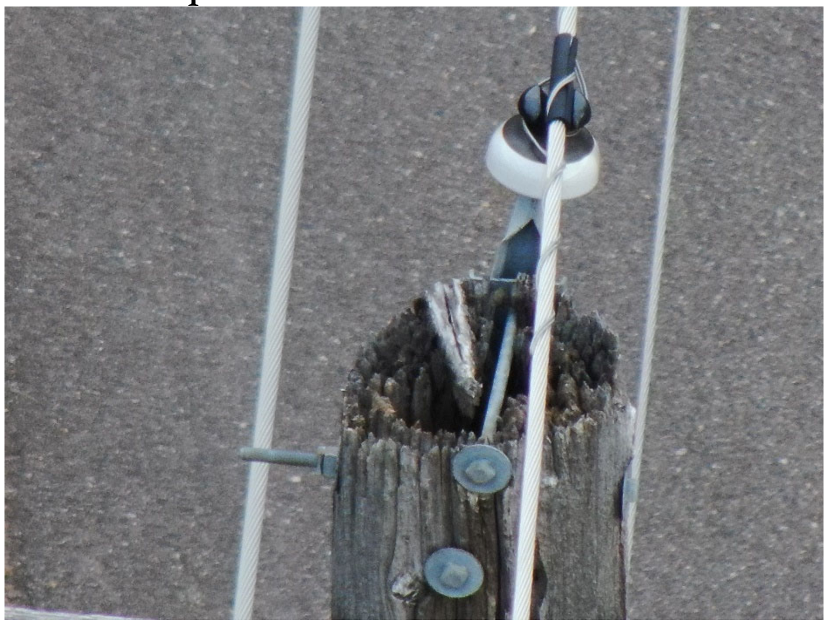
Figure A2 - 1: NSPM Wood Pole Inspection Failures by Age



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 in poor condition is a major contributor to outages and storm related interruptions. Replacing this degraded equipment will harden the system and improve system performance especially during high wind conditions, icing, and heavy snow.

The pole top program is planned to begin in the near future. 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 in Figure A2-2.

Figure A2 - 2: Example Drone Photo – Wood Pole with Decayed Top

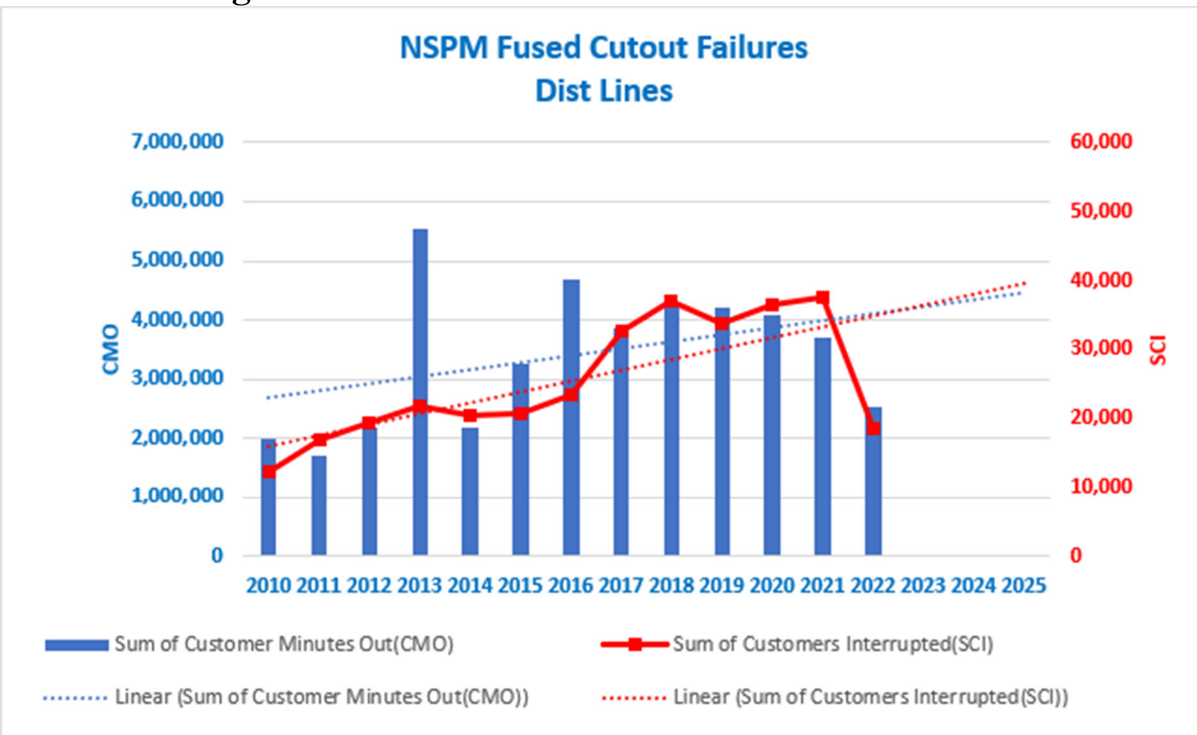


E. Porcelain Cutout Replacement Program

This program started in 2022 and is focused on replacing porcelain cutouts with polymer cutouts on overhead feeders. Cutouts are a mounting device for holding a protective fuse and are used to provide overcurrent protection on overhead feeders. Porcelain cutouts can 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 during power restoration operation. 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.

Along with many other utilities, the Company 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 roughly 100,000 porcelain cutouts on its system and these porcelain cutouts had been experiencing an increased rate of premature failures prior to our cutout replacement program. In recent years we have transitioned from the pilot program to a larger scale of cutout replacements and have seen a reduction in failure and outage rates. In these stages of the program, it is unknown whether these changes are attributed to replacements or failure patterns. Figure A2-3 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. Figure A2-3 also shows the projected trajectory of failures if the cutouts are not addressed.

Figure A2 - 3: NSPM Fused Cutout Failures 2010-2022



F. Other Programs and Initiatives

Another area we expect to make greater investments in the near-term is in our Substation Renewal program, 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 transformer failure 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 and 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 – among other things – enable the Company to perform upgrades and maintenance on existing substations. Additionally, this allows quicker restoration of power to customers when a substation transformer fails and a new permanent transformer must be installed (a process that can take several weeks, notwithstanding the supply chain constraints discussed above).

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 been installing NESC Grade B construction, which typically requires 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. 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. Installing underground cables in conduit can reduce failures and extend cable life. Conduit is beneficial where dig ins are common, at road crossings, rocky soil, wet locations, and areas where freeze/thaw cycles occur. Additionally, installing cables in conduit reduces replacement costs, dig in disruptions, and reduces disruption when cables require replacing.

III. RELIABILITY MANAGEMENT

Each year, the Company 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 both of our annual service quality filings as required under our tariff as well as the Minnesota Rules.[2] However, we provide a brief summary here of relevant sections from those reliability reports.

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[2] 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-23-73.

A. Reliability Indices

In this section, we provide a snapshot of our 2022 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 Customers Experiencing Multiple Interruptions (CEMI) tools to better reflect the customer experience.

In 2022, we achieved a SAIDI result of 87.92 minutes, which exceeds our Quality of Service Plan tariff goal of 133.23 minutes.[3] Our 2022 System Average Interruption Frequency Index (SAIFI) result of 0.84 outage events also exceeds the QSP tariff goal of 1.21 outage events.[4]

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 2022 targets under three methodologies (including storms, our QSP Tariff, and the Minnesota Annual Rules). These three tables are combined and presented below as Table A2-2.[5]

[3] 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.
[4] In this context, "exceeding" the goals is a positive result, reflecting good system performance.
[5] As filed in 2022 Annual Report and Petition Service Quality Performance and Proposed Reliability Measures, Docket No. E002/M-23-73; March 31, 2023 (Part 2, Page 30).

Table A2-2: Reliability Indices and Performance

Historical Reliability Indices & Major Event Day Exclusions

All Days[1]		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Minnesota	SAIDI	562.11	116.43	184.50	214.39	141.70	125.00	124.50	134.19	129.93	184.42
	SAIFI	1.39	0.92	0.96	1.05	0.90	0.95	0.86	1.07	1.04	1.08
	CAIDI	404.36	126.00	192.32	204.84	158.10	131.22	145.30	124.89	124.67	170.24
Metro East	SAIDI	352.30	123.54	177.19	223.67	136.51	112.11	104.57	124.02	145.50	142.85
	SAIFI	1.27	0.98	1.04	1.08	0.95	0.96	0.85	1.07	1.01	1.05
	CAIDI	278.46	125.93	169.86	206.85	144.37	116.71	122.52	115.72	144.49	136.23
Metro West	SAIDI	810.01	105.98	229.78	198.25	148.58	88.23	79.92	143.84	121.15	214.14
	SAIFI	1.55	0.89	1.00	1.00	0.86	0.92	0.74	1.13	1.14	1.11
	CAIDI	523.66	118.70	229.92	198.86	173.27	95.70	107.38	127.72	106.02	193.13
Northwest[4]	SAIDI	468.22	82.82	75.61	225.74	173.71	109.50	150.82	133.55	104.01	244.83
	SAIFI	1.40	0.82	0.66	1.07	0.98	0.87	0.94	0.98	0.79	1.19
	CAIDI	335.53	101.00	115.40	211.50	177.46	126.02	160.71	135.77	131.22	205.14
Southeast[5]	SAIDI	179.29	173.45	98.23	249.05	96.37	353.32	374.19	122.43	144.95	123.52
	SAIFI	1.06	0.98	0.79	1.15	0.84	1.15	1.32	0.92	0.92	0.97
	CAIDI	168.93	176.51	125.07	217.15	114.75	307.95	283.40	132.38	157.71	126.95

MN Tariff[2]		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	'22 Target
Minnesota	SAIDI	91.12	79.85	86.83	89.49	73.80	93.26	76.66	95.52	87.97	87.92	133.23
	SAIFI	0.86	0.78	0.79	0.81	0.72	0.85	0.70	0.96	0.90	0.84	1.21
	CAIDI	106.51	102.07	109.90	110.54	102.10	109.90	109.74	99.73	97.71	104.63	NA
Metro East	SAIDI	83.56	77.58	93.71	95.49	75.70	103.28	79.26	104.56	81.96	96.62	
	SAIFI	0.83	0.82	0.90	0.87	0.75	0.92	0.72	0.99	0.83	0.89	
	CAIDI	100.72	94.81	104.58	110.07	100.79	112.40	110.29	105.19	98.36	108.37	
		3	3	2	3	3	1	2	1	2	4	
	MED's	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	8/24, 9/17	5/11, 8/3, 8/27, 12/15	
Metro West	SAIDI	101.24	81.85	88.98	82.90	69.28	81.25	68.25	87.46	94.47	81.22	
	SAIFI	0.96	0.82	0.82	0.82	0.70	0.84	0.69	1.01	1.05	0.86	
	CAIDI	105.85	100.15	108.90	101.51	98.40	96.63	99.17	86.19	89.83	94.52	
		5	1	1	3	2	1	2	4	2	4	
	MED's	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	8/26, 9/17	5/11, 5/12, 8/3, 8/27	
Northwest[4]	SAIDI	85.78	62.16	69.39	80.19	69.41	99.87	61.17	100.31	89.90	79.19	
	SAIFI	0.75	0.61	0.57	0.56	0.64	0.73	0.53	0.75	0.63	0.63	
	CAIDI	113.87	102.05	121.05	143.58	107.70	137.06	115.94	133.14	141.66	125.90	
		2	0	0	4	1	0	5	3	0	5	
	MED's	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	None	1/16,5/12,5/30, 6/20, 6/24	
Southeast[5]	SAIDI	73.58	94.45	70.78	109.59	92.84	110.67	122.21	99.53	75.14	99.26	
	SAIFI	0.57	0.67	0.52	0.82	0.79	0.77	0.84	0.76	0.66	0.78	
	CAIDI	129.93	141.93	135.23	133.06	117.19	144.04	145.17	130.46	114.59	126.96	
		4	4	1	3	0	2	4	1	3	1	
	MED's	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	7/29, 12/15, 12/16	5/11	

Annual Rules[3]		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	'22 Target[6]
Minnesota	SAIDI	94.27	84.00	89.95	90.45	75.04	96.07	81.02	98.92	88.83	90.00	NA
	SAIFI	0.90	0.84	0.83	0.83	0.74	0.89	0.75	0.99	0.92	0.86	NA
	CAIDI	104.60	99.67	108.09	108.93	100.90	107.39	108.29	100.28	96.33	104.05	NA
Metro East	SAIDI	85.05	79.73	93.73	95.52	76.22	103.69	80.56	104.98	82.00	96.79	115.00
	SAIFI	0.86	0.86	0.90	0.87	0.76	0.93	0.75	1.01	0.83	0.90	1.02
	CAIDI	99.33	92.46	104.25	109.70	100.48	111.74	107.36	103.69	98.41	107.99	120.00
		3	3	2	3	3	1	2	1	2	4	
	MED's	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	8/24, 9/17	5/11, 8/3, 8/27, 12/15	
Metro West	SAIDI	101.41	83.02	90.95	83.64	69.51	83.26	69.50	88.82	94.56	81.85	115.00
	SAIFI	0.96	0.84	0.84	0.82	0.71	0.87	0.70	1.00	1.05	0.87	1.02
	CAIDI	105.45	98.50	108.44	101.43	97.84	95.47	99.15	88.53	89.67	94.19	120.00
		5	1	1	3	2	1	2	4	2	4	
	MED's	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	8/26, 9/17	5/11, 5/12, 8/3, 8/27	
Northwest[4]	SAIDI	97.43	82.80	75.58	85.81	75.77	109.34	89.07	121.94	93.42	84.06	143.00
	SAIFI	0.94	0.82	0.66	0.70	0.76	0.87	0.78	0.93	0.74	0.69	1.11
	CAIDI	103.70	101.02	115.39	122.38	100.28	126.05	113.48	130.98	126.13	122.38	134.00
		2	0	0	5	1	0	3	1	1	5	
	MED's	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	8/29	1/16,5/12,5/30, 6/20, 6/24	
Southeast[5]	SAIDI	87.98	103.45	86.51	110.23	96.33	118.80	129.10	105.07	79.80	111.84	143.00
	SAIFI	0.73	0.80	0.75	0.85	0.84	0.92	0.93	0.87	0.76	0.91	1.11
	CAIDI	120.39	129.20	115.16	130.02	114.73	129.64	138.99	120.29	105.14	122.69	134.00
		4	4	1	3	0	2	4	1	3	1	
	MED's	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	7/29, 12/15, 12/16	5/11	

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
6) 2012-2020 Annual Rules Targets were based on 5 year rolling actual averages or locked targets.
2021 & 2022 Annual Rules Targets are based on IEEE Working Group Benchmarking study Large Utility Group 2nd Quartile for Metro East & West Medium Utility Group 2nd Quartile for Northwest & Southeast,

The Company developed tools that allow us to better track the causes of our CEMI. 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 to help identify and plan for reliability concerns.

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 equipment failure, 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 Table A2-3 called the 'Star Chart' on the following page.[6] 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.

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[6] As filed 2022 Annual Report and Petition Service Quality Performance and Proposed Reliability Measures, Docket No. E002/M-23-73 (Part 2, Attachment J, Page 3 of 7).

Table A2-3: Reliability Management Program Impacts (Star Chart)

NSPM Program Summary

	Funded Programs	Description	2020 Actuals (k$)	2021 Actuals (k$)	2022 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.	1,011	695	3,271	★		★	★
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.	143	250	668			★	★
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.	1,719	530	4,448	★			★
Reliability	**Tap (URD) Cable,** (UG)		26,470	23,113	31,980	★	★		★
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.	65	0	0	★		★	★
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.	40	58	45	★			
Reliability	**Vegetation Management** (Transmission & Distribution)	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.	20,633	29,908	35,522	★		★	★
Integrity	**Pole Assessment & Replacement** (Distribution)	Pole Assessment include an above groundline visual inspection. Groundline inspections are based on age and environment and may include visual, sound and bore and excavation. Life extension preservative treatments occur on majority of poles starting in 2021.. Based on results poles may be tagged for replacement.	28,285	30,208	25,621	★	★		
Integrity	**Transmission Substation**	Replaces end-of-life equipment in order to reduce maintenance costs and improve reliability.	2,863	14,127	15,373	★			
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.	2,239	5,021	5,200	★			★

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, Customer Average

Interruption Duration Index (CAIDI), CEMI, and Customer Complaints. We note that *Appendix D: Distribution Financial Information* provides estimated spending on reactive versus proactive cable replacements.

Table A2-4 below outlines primary program indicators for our key initiatives/programs.[7] 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 Reliability Management Key initiatives outlined in Table A2-4 please refer to the Star Chart in Table A2-3 above.

Table A2-4: Reliability Management Key Initiatives

	2022	2021	2020	2019	2018	2017	2016
Vegetation Management Program							
Total Overhead Distribution miles completed	2,239	2,019	1,606	2,647	2,307	2,417	2,086
Total Overhead Transmission miles completed	807	754	762	896	768	762	1,039
Normalized Tree-coded Sustained Cust Ints.(W/O Storms)	231,463	168,848	184,302	170,994	214,299	145,422	155,370
Non-normalized Tree-coded Sustained Cust Ints.(With Storms)	405,731	285,454	286,735	242,158	243,867	277,068	305,946
Underground Cable Replacement Program							
# of Segments That Have Been Replaced (est.)	2,591	2,252	2,579	1,158	1,504	1,411	1,378
# of Failures(Only on Primary Cable)	1,429	1,656	1,459	1,301	1,366	1,453	1,607
Feeder Infrared Evaluation(FIRE)							
# of Feeders Scanned	270	276	259	280	209	248	275
# of Hot Spots Corrected	16	28	66	55	67	71	68
Feeder Performance Improvement Plans(FPIP)							
Investigations Completed	91	97	112	111	108	113	105
Wood Pole Inspection Plan							
Total Distribution Wood Poles Inspected	42,330	39,045	40,179	10,312	33,720	17,972	18,845
Total Transmission Wood Poles Inspected	4,329	4,945	3,124	3,381	2,464	4,000	4,660

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 staff 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 in Table A2-5[8] below, we assess and prioritize the actions based on a balance of their ability to positively impact

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[7] As filed in our 2022 Annual Report and Petition Service Quality Performance and Proposed Reliability Measures, Docket No. E002/M-23-73 (Part 2, Attachment J, Page 4 of 7).
[8] As filed in our 2022 Annual Report and Petition Service Quality Performance and Proposed Reliability Measures, Docket No. E002/M-23-73 (Part 2, Attachment J, Page 6 of 7).

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 A2-5: 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
	Frequency	System Integrity	Substation inspection done on every substation specific to identifying animal incursion risk and vegetation issues, in addition moving to an electronic work collection APP to track and prioritize timely maintenance.	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 personel 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 Parternership	Partner with Vegetaiton 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. Idnetify 336 auto splices. Continured 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	ADMS (Advanced Distribution Management System) application is live in all NSP Control Centers (4); as the application matures, we are working to locate the fault on the cuircuit to cut down on the response time.	High
	CAIDI	Model 1/0 Switching	Standard operating procedure 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	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 reliablity performance.	Low
Reliability Team/ Communications	CAIDI	Outage Reviews	Root Cause Invesigation of outages greater than 90 minutes or 0.1 SAIDI	Medium
	CAIDI	Continious Improvement	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 Appendix, 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. Section II 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/Locating, 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.

The Company is an industry leader in storm response. For example, in 2023, the Company was recognized by the Edison Electric Institute (EEI) with the Emergency Recovery Award for our excellent storm response and restoration efforts following the April Fools' Day snowstorm that swept the Upper Midwest in spring 2023. From March 30 to April 1, the powerful low-pressure system brought rain, thunderstorms, sleet, 50 mile-per-hour winds, and heavy snow to Minnesota and Wisconsin. The storm resulted in widespread power outages, tree and limb damage, and new daily precipitation records in the Twin Cities and Rochester. The same system also produced tornadoes and severe weather in neighboring Iowa. The storm left the largest snow totals in the eight- to 12-inch range in portions of west-central, central, east-central and southern Minnesota, with some areas reporting up to 13 inches of snow. Approximately 300,000 customers lost power as a result of the April 1 snowstorm. Over 1,200 employees and contractors were deployed from 10 states to help restore power to the 180,000 customers who suffered sustained outages. Our damage assessment teams in Minnesota and Wisconsin provided our crews with valuable information to make restoration efforts efficient as crews made critical repairs.

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 (MED) exclusions. Due to detailed response plans, drills, and pre-staging of crews, we can complete restoration sooner for our customers. Past process was to react after the storm had passed, which would allow for MED exclusions of customer minutes out and improved System Average Interruption Duration Index (SAIDI). However, this approach does not 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, serve as dispatch centers, or 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 can quickly implement plans that involve staging equipment or non-local crews. We have over 100 staging sites identified inside of our customer footprint – and we ensure we have street and feeder maps readily available for them to use. Our planning also incorporates details that 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 clearer, we inform office staff, field workforces, and strategic communications partners, which includes the call centers, external communications, community relations, and regulatory affairs, among other business areas. 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 labor 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 because 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.

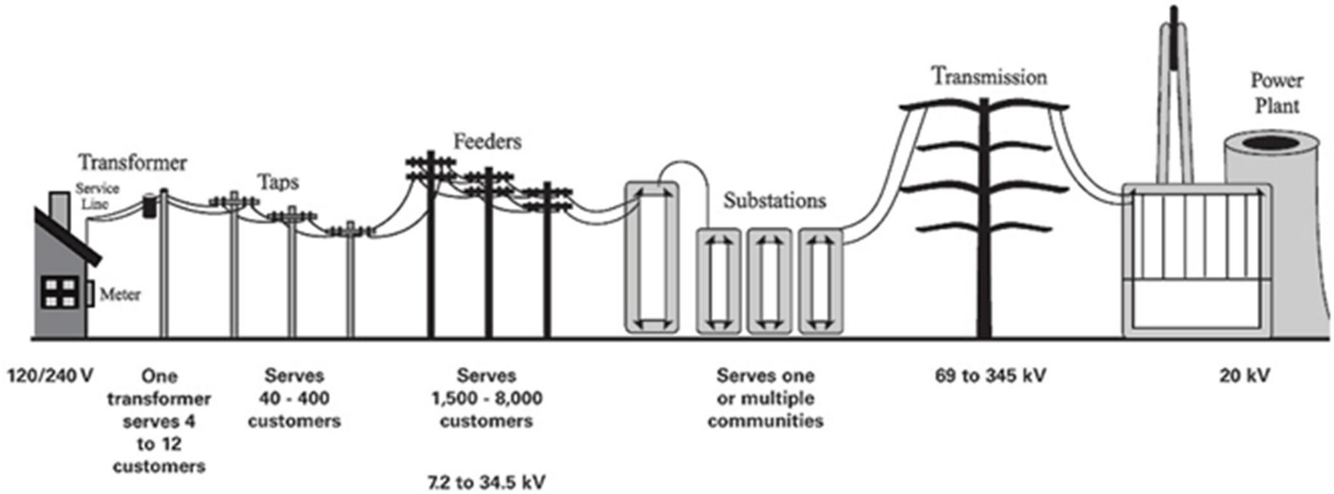
As soon as the Company knows there is an outage, a crew is dispatched to investigate. When the crew arrives on the scene, it assesses the problem and proceeds with the repair. Due to the complexity of the Company's electric system and the variety of potential causes of an outage, this process can take 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 first responders update the estimated restoration time using mobile data terminals in their vehicle.

The Company's 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 safely 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 A3-1 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.

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

Figure A3 - 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. However, we note 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 entire communities. Generally, damaged or failed transmission facilities do not cause customer outages due to the interconnected nature of the transmission grid. Even so, 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, home, or serve multiple customers (generally 4 to 12 customers). Service wires connect transformers to individual residences and businesses.

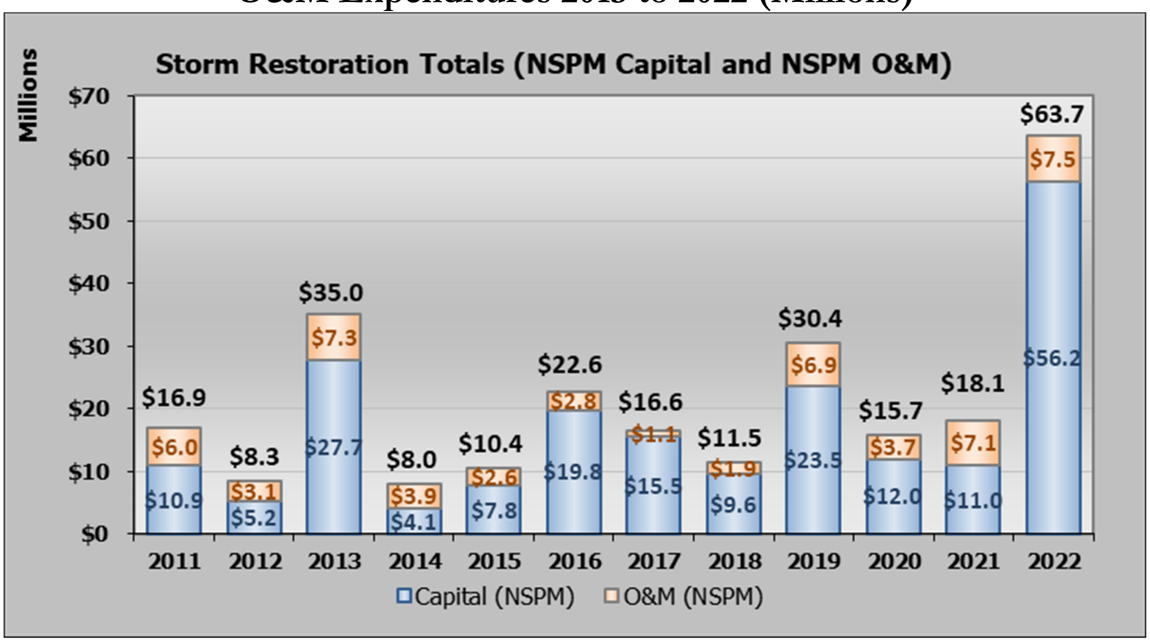
Sometimes, a tap, feeder, or substation outage will be restored while a transformer or an individual customer (service) may remain without power. This type of outage may go undetected at first until the customer notices that their neighbors have power, or they receive a notification that their electricity has been restored, when in fact, it has not. Advanced Metering Infrastructure (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. We discuss these benefits further in Transmission Cost Recovery Rider dockets (see Docket No. E002/M-21-814).

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.

Figure A3-2 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]

Figure A3 - 2: Escalated Operations – State of Minnesota Electric Capital and O&M Expenditures 2013 to 2022 (Millions)



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

In terms of budgeting for storm restoration, due to 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

Vegetation Management helps keep outages to a minimum, reduces the potential for the public to come in contact with electric lines, and helps line crews access the line for maintenance and outage restoration. Specific activities include 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 service interruptions.

Vegetation Management activities fall into four categories: outage response, customer requested work, routine maintenance work, and Company construction clearance work. The largest category of work, representing approximately 86 percent of annual Vegetation Management spend, is routine maintenance. Routine maintenance is proactive work to remove trees or brush that may impact the reliability of our electric service. This work is planned via a hybrid approach that includes both time-based cycle (generally 4-5 years) and risk-based modeling that utilizes satellite imagery and

AI analytics. In mid-2023, we postponed routine maintenance work to allow crews to focus on higher priority work that is required to maintain safety, support outage restoration, and respond to high priority customer requests. Routine work will be completed in future years.

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 A3-1 below the volume of requests for electric facilities locates over the recent past:

Table A3 - 1: NSPM Electric Locates Volumes (2016-2026)

2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actual	2022 Actual	2023 Forecast	2024 Budget	2025 Budget	2026 Budget
446,383	460,483	459,904	470,697	502,348	489,115	471,205	498,838	513,803	529,217	545,094

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 can select vehicles to replace 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.

We note that as of 2019, fleet-related capital and O&M costs are budgeted separately and not included in the Distribution function budget.

APPENDIX A4: DISTRIBUTION SYSTEM STATISTICS

In this Appendix, 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 by Requirements 3.A.2 and 3.A.3 into Table A4-1 below.

Table A4 - 1: Feeder Load Monitoring (FLM) – State of Minnesota

FLM Type	% of subs[1]	Measurement	Measurement Interval	Automated /Manual	Frequency of reads	Min/ Max	Daytime/ Nighttime
Full FLM	55%	3 phase Amps, MW, MVar, MVA, kV	Hourly	Auto	Continuous[2]	Yes- *Manual effort*	Both
Partial FLM	17%	Has some or most of the above data points, varies by location	Hourly	Auto	Continuous[2]	Yes- *Manual effort*	Both
No FLM	28%	Only manual reads available (provides 3 phase Amps)	Varies	Manual	Varies	No	Neither

Note: More than 95 percent 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 Supervisory Control and Data Acquisition (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 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 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 more than 95 percent of our customers; 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 (DML) for all feeders equipped with this functionality, but it takes extra manual effort to derive a DML. This is because hourly loading data must be migrated from the SCADA data warehouse into a spreadsheet and then filtered down to focus on the hours of the day for which DML applies. This process cannot be automated or scripted to simply select the minimum value in the annual hourly loading within the daytime hours because SCADA data is often obfuscated by abnormal switching events and other data anomalies. While these anomalies arise due to normal operation of the distribution system to manage system conditions in real time, they are not adequately representative of the minimum load under the normal system configuration and therefore, must be ignored. After making these judgements, Distribution Planning Engineers must then repeat this process to record three minimum load values: absolute minimum (all 24 hours of the day), DML for tracking solar PV (between the hours of 8 a.m. and 6 p.m.), and DML for fixed solar PV (between the hours of 10 a.m. and 4 p.m.). Finally, the entire DML identification process must then be repeated for more than 1,000 feeder circuits in the state of Minnesota.

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 approximately 72 percent of our substations. Similar to customers served from substations and feeders with full- or partial-FLM, more than 95 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 three to five substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA. The 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 bulk system peak in 2022 was 9,245 MW, which occurred at 5:00 p.m. on June 20, 2022. The Minnesota portion of this peak was 6,973 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 95 percent of our Minnesota customers.

In order to provide the maximum coincident hourly load, we must manually pull the maximum hourly load for each SCADA-enabled substation for the date and time of the NSP System. In prior IDPs, we have completed this manual task, and in 2021 noted that 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. We did not receive any feedback. In light of this, and the many new requirements for this year's IDP, we did not expend the manual hours necessary to report on this requirement. Should the Commission or stakeholders desire this information, we will work to provide it; otherwise, we ask that this filing requirement be discontinued.

The Commission's IDP Requirements for the Company state:

> *For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement:*
>
> 1. *Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive;*
> 2. *How the information could be obtained, at what estimated cost, and timeframe;*
> 3. *What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives;*
> 4. *If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.*

Regarding #1, while calculating the maximum hourly coincident load for the distribution system is possible, providing the information is time and resource intensive because of the manual process needed to calculate the information. We have not received any information from stakeholders on how this requirement helps achieve the Commission's Planning Objectives or how the data is being used.

Regarding #2, the information can be obtained. We estimate it takes approximately four hours to pull SCADA data and manual calculate the maximum hourly coincident load for the distribution system; however, the resulting value is incomplete at best, representing the net load and also missing data because some substations have partial or no SCADA functionality.

Regarding #3, we do not believe the information is crucial to achieving the Commission's planning objectives, but we are open to hearing from other parties if they feel the information is indeed crucial.

Regarding #4, we have provided the NSP and system peak information above, and we can continue to provide that information, which we believe meets the Commission's Planning Objectives. We are open to providing the hourly coincident load information if the Commission or parties deem it useful to comply with the Commission's planning objectives; otherwise, we suggest this requirement be discontinued.

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.

As of September 30, we have installed approximately 512,250 AMI meters in Minnesota. In total, we plan to complete deployment of approximately 1.4 million AMI meters in 2025. We discuss the available and planned AMI functionality, and our AMI plans in more detail in *Appendix B1: Grid Modernization* of this IDP. In addition, we are filing our first AMI Annual Report today (November 1, 2023) in Docket No. E002/M-21-814.

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's 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 A4-2 below.

Table A4 - 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. Also, transformers and electric meters have no-load losses, which are a function of voltage. Voltages in U.S. 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. 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 in 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, Field Area Network (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, and
- 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 2023 loss percentages for the state of Minnesota, as provided in Table A4-3 below.

Table A4 - 3: 2023 System Loss Percentages – State of Minnesota

Minnesota	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bulk(UT)	0.9470	0.9465	0.9445	0.9448	0.9481	0.9498	0.9489	0.9489	0.9486	0.9475	0.9467	0.9465
Bulk(T)	0.9413	0.9410	0.9387	0.9393	0.9430	0.9447	0.9436	0.9437	0.9438	0.9426	0.9411	0.9410
Tran(UT)	0.9361	0.9358	0.9335	0.9344	0.9384	0.9398	0.9386	0.9388	0.9395	0.9382	0.9361	0.9357
Tran(T)	0.9345	0.9342	0.9319	0.9329	0.9370	0.9384	0.9370	0.9375	0.9382	0.9368	0.9345	0.9340
Subtran(UT)	0.9269	0.9267	0.9243	0.9256	0.9307	0.9315	0.9299	0.9309	0.9318	0.9308	0.9271	0.9263
Subtran(T)	0.9213	0.9211	0.9187	0.9200	0.9248	0.9254	0.9235	0.9246	0.9260	0.9252	0.9214	0.9207
Primary	0.9082	0.9092	0.9076	0.9085	0.9111	0.9073	0.9031	0.9063	0.9118	0.9130	0.9086	0.9076
Large Secondary	0.8957	0.8962	0.8938	0.8947	0.8981	0.8945	0.8903	0.8935	0.8984	0.8988	0.8956	0.8950
Small Secondary	0.8871	0.8874	0.8849	0.8852	0.8863	0.8808	0.8758	0.8808	0.8865	0.8891	0.8865	0.8862

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 – State of Minnesota distribution substation capacity = 13,504,706 kVA or 13,505 MVA.

The total distribution substation capacity is reflective of substations that are active, functional, and owned by the Company as of July 1, 2023. 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 August 2023, we approximated our primary overhead conductor at 13,263 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 August 2023, we approximated our primary underground cable at 10,496 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 2023, we had 1,540,003 electric premises in the NSPM operating company, with 1,341,847 of those in our Minnesota service area specifically.