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October 25, 2021

VIA E-FILING
Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's 2021 Integrated Distribution Plan
Docket No. E015/M-21-390

Dear Mr. Seuffert:

Minnesota Power (or "the Company") is pleased to present its 2021 Integrated Distribution Plan ("2021 IDP"), which details the Company's plans to ensure a reliable and increasingly resilient electric grid as it continues the transformation of its power supply to a cleaner energy future. Through Minnesota Power's *Energy**Forward*** strategy, it became the first Minnesota utility to deliver 50 percent renewable energy to its customers. The Company has executed this transformation while continuing to ensure safe, reliable, and affordable energy to its customers. A resilient and secure grid becomes ever more important as technology evolves, customer expectations change, climate change results in increased extreme weather events, and the power supply becomes more renewable.

Minnesota Power appreciates the opportunity to submit this 2021 IDP. If you have any questions regarding this filing, please contact me at (218) 355-3186 or arittgers@mnpower.com.

Respectfully,

Anne Rittgers
Public Policy Advisor

AWR:th
Attach.

MINNESOTA POWER

2021 INTEGRATED DISTRIBUTION PLAN

minnesota power

AN ALLETE COMPANY

EnergyForward

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2021 Integrated Distribution Plan	Docket No. E015/M-21-390

SUMMARY OF FILING

Minnesota Power (or "the Company") respectfully submits this second biennial Integrated Distribution Plan ("2021 IDP") to the Minnesota Public Utilities Commission ("Commission") in accordance with relevant Commission-issued orders, including the Commission's February 20, 2019 Order (Docket No. E-015/CI-18-254) adopting filing requirements and the Commission's May 27, 2020 Order accepting the Company's 2019 IDP and modifying filing requirements (Docket No. E-015/M-19-684). Minnesota Power continues to advance the transformation of its power supply to a cleaner energy future through its *Energy**Forward*** strategy and at the end of 2020, became the first Minnesota utility to generate 50 percent of its electricity from renewable sources. The Company has executed this transformation of its power supply while continuing to provide safe, reliable, and affordable energy for all customers. A resilient and secure grid becomes ever more important as technology evolves, customer expectations change, climate change results in increased extreme weather events, and the power supply becomes more renewable. Resiliency is a key component of Minnesota Power's *Energy**Forward*** strategy and the 2021 IDP details the Company's distribution planning processes and continuous foundational investments for a grid that will continue to provide the essential services customers rely on.

Procedural Matters

Pursuant to Minn. Stat. § 216B.16, subd. 1 and Minn. Rule 7829.1300, Minnesota Power provides the following required filing information.

Summary of Filing (Minn. Rule 7829.1300, subp.1)

A one-paragraph summary accompanies this Petition.

Service on Other Parties (Minn. Rule 7829.1300, subp. 2)

Pursuant to Minn. Stat. § 216.17, subd. 3 and Minn. Rule 7829.1300, subp. 2, Minnesota Power eFiles the Petition on the Department of Commerce - Division of Energy Resources ("the Department") and the Minnesota Office of the Attorney General - Antitrust and Utilities Division. A summary of the filing prepared in accordance with Minn. Rule 7829.1300, subp. 1 is being served on Minnesota Power's general service list.

Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 4(A))

Minnesota Power
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Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 4(B))

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Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Petition is being filed on October 25, 2021. The effective date is the date of the Commission's Order or such other date as directed in the Commission's Order. The Petition will not result in any rate changes.

Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 4(D))

There is no specific statutorily prescribed timeframe for processing this filing. Accordingly, this filing is controlled by the Commission's rules on Miscellaneous Filings, Minn. R. 7829.1300 and 7829.1400.

Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))

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Service List (Minn. Rule 7829.0700)

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ACRONYM/DEFINED TERM	DEFINITION
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AICHO	American Indian Community Housing Organization
ANSI	American National Standards Institute
AFR	Annual Forecast Report
AMR	Automated Meter Reading
BESS	Battery Energy Storage System
CDC	Centers for Disease Control
CAGR	Compound Annual Growth Rate
CIP	Conservation Improvement Program
CVR	Conservation Voltage Reduction
CBSP	Consumer Behavior Study Plan
CPP	Critical Peak Pricing
CIS	Customer Information System
C2M	Customer to Meter
DR	Demand Response
DSM	Demand-Side Management
DMR	Digital Mobile Radio
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resource
DERMS	Distributed Energy Resources Management System
DG	Distributed Generation
DA	Distribution Automation
DGWG	Distribution Generation Working Group
DMS	Distribution Management System
DRIVE	Distribution Resource Integration and Value Estimation
DE&I	Diversity, Equity, and Inclusion
D-VAR	Dynamic Volt-Amperes Reactive
EPRI	Electric Power Research Institute
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
ECO Act	Energy Conservation and Optimization Act of 2021
EMS	Energy Management System
EDR	Enterprise Detection and Response
FLISR	Fault Location, Isolation, and System Restoration
FCI	Faulted Circuit Indicators
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information Systems/Utility Network Model
GRPU	Grand Rapids Public Utilities
GWh	Gigawatt Hours
ISO	Independent System Operator
IT	Informational Technology
IEEE	Institute of Electrical and Electronic Engineers
IDP	Integrated Distribution Plan
IRP	Integrated Resource Plan
IBR	Inverted Block Rate
kVArH	KiloVAR-Hour
kW	Kilowatt
kWh	Kilowatt-Hour
LMR	Land Mobile Radio

ACRONYM/DEFINED TERM	DEFINITION
LED	Light Emitting Diode
LI Solar	Low Income Solar
LIHEAP	Low Income Home Energy Assistance Program
MDM	Meter Data Management
MISO	Midcontinent Independent System Operator
MN-DIP	Minnesota Distributed Generation Interconnection Process
MPLS	Multiprotocol Label Switching
MW	Megawatt
MWh	Megawatt Hours
OT	Operational Technology
O&M	Operations and Maintenance
OMS	Outage Management System
PLMA	Peak Load Management Alliance
PV	Photovoltaic
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
RREAL	Rural Renewable Energy Alliance
SOAR	Security Orchestration Automation and Response
SGG	Smart Grid Gateway
SGIG	Smart Grid Investment Grant
SEPA	Smart Electric Power Alliance
SES	Minnesota Solar Energy Standard
STATCOM	Static Synchronous Compensator
SCADA	Supervisory Control and Data Acquisition
TIIR	Technical Interconnection and Interoperability Requirement
TSM	Technical Specification Manual
TOD	Time-of-Day
TOU	Time-of-Use
TCCAP	Tri-County Community Action Partnership
VEE	Validation, Editing, and Estimating
VVO	Volt-VAR Optimization

SECTION I:

Introduction

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2021 Integrated Distribution Plan	Docket No. E015/M-21-390

I. INTRODUCTION

Minnesota Power's (or "the Company") 2021 Integrated Distribution Plan ("2021 IDP") provides information on each of the Minnesota Public Utilities Commission ("Commission") 2021 IDP objectives described below. In order to evaluate Minnesota Power's long term distribution planning efforts, it is important to understand the Company, its unique customer mix, and service territory. Included in this section is an overview of Minnesota Power, how the Company is navigating the COVID-19 pandemic, its *Energy**Forward*** strategy, and a brief overview of current systems relevant to a discussion on distribution planning efforts.

A. Integrated Distribution Plan Procedural History

In its Order dated February 20, 2019,[1] the Commission adopted IDP filing requirements and ordered Minnesota Power to file an IDP biennially beginning on November 1, 2019. Minnesota Power's first IDP filing in 2019 provided information about the Company's distribution system and highlighted continuous foundational investments related to serving customers, ensuring reliability and preparing for a more resilient grid. In an Order dated May 27, 2020,[2] the Commission accepted Minnesota Power's 2019 IDP and modified future filing requirements, detailed in Appendix A. The Order also required Minnesota Power to continue to incorporate stakeholder-suggested improvements in the 2021 filing.

As outlined in the May 27, 2020 Order, the Commission has identified the following objectives of IDPs:

[1] Docket No. E-015/CI-18-254.
[2] Docket No. E-015/M-19-684.

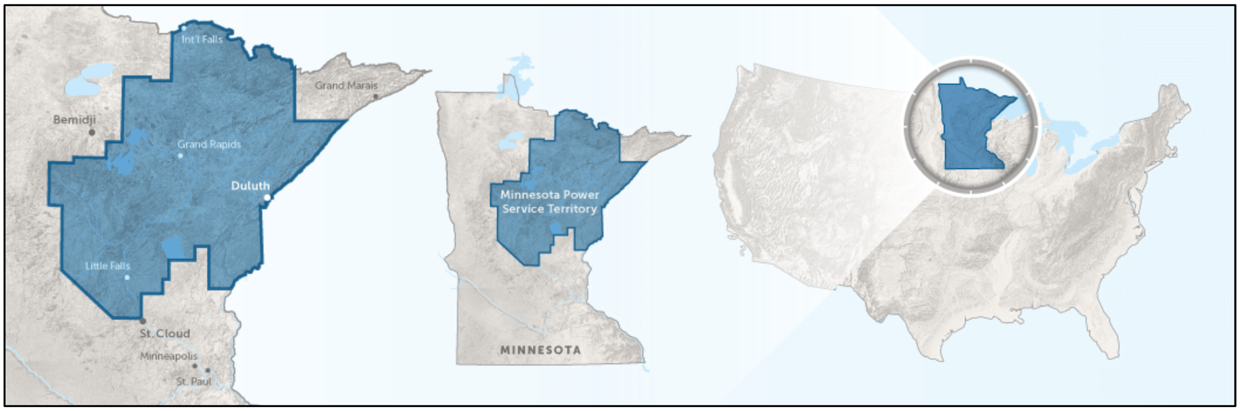
- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility'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.

Minnesota Power respectfully submits this 2021 IDP, which provides information on how the Company is meeting the Commission's distribution planning objectives, as outlined above.

B. Minnesota Power Overview

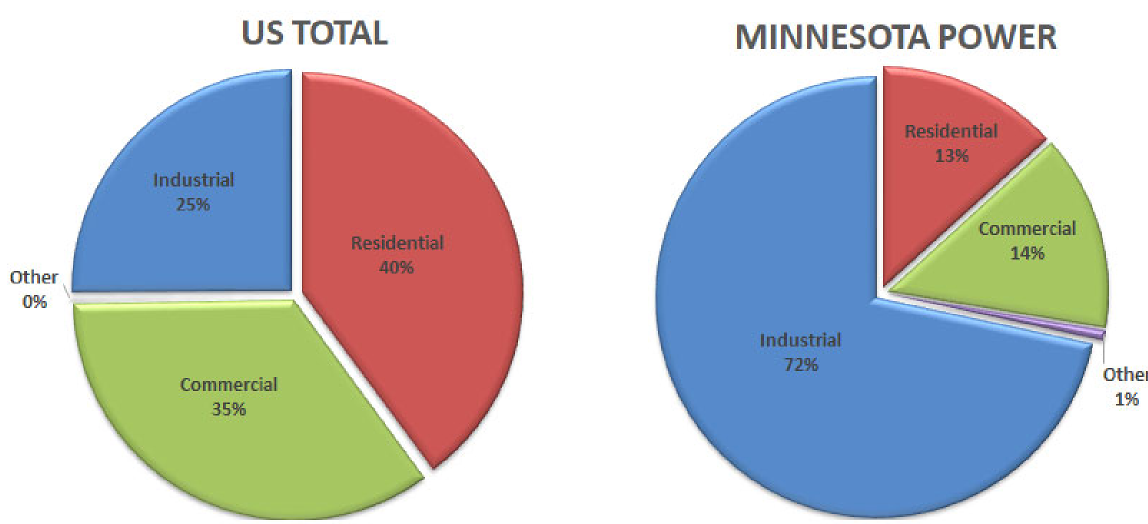
Minnesota Power is transforming the way it energizes communities and businesses through its *Energy**Forward*** resource strategy. First incorporated in 1906, Minnesota Power serves electricity to over 145,000 residential and commercial customers, 15 municipal systems, and some of the nation's largest industrial customers across northeastern and central Minnesota. Minnesota Power's distribution system is comprised of 6,170 miles of distribution lines and 201 distribution substations ("distribution system"). Minnesota Power's service territory spans over 26,000 square miles from International Falls in the north to Royalton in the south, and from Duluth in the east to as far west as the Long Prairie and Park Rapids communities as shown in Figure 1 on the next page.

Figure 1: Minnesota Power's Service Territory



Minnesota Power's customer mix is unique and distinct from most utilities in the United States as shown in Figure 2. This unique customer mix has implications on system planning, as described further below.

Figure 2: Minnesota Power's Customer Concentration is Unique



Source: EIA 2020 Sales of Electricity to Ultimate Customers, Minnesota Power Retail Energy Sales (2020)

Minnesota Power's commercial customers account for approximately fourteen percent of annual regulated retail electric sales revenue and are served directly from the distribution system. A wide range of interactions occur with commercial customers including planning for new construction, service extensions, outage restoration, reliability and power quality concerns, system upgrades, and responding to a variety of other electric service and rate questions. These customers are a diverse group with varying needs and expectations depending on the business (i.e., electric costs as a percentage of total operating/production costs, power quality and reliability needs, etc.). Reliability is of the utmost priority to commercial customers, and for many of these customers, any interruption in electric service has the potential to stop business and immediately impact their bottom line. For example, customer businesses consisting of office workers may no longer have access to the internet or phones and productivity drops, retailers may lose the ability to conduct business resulting in lost revenue, and manufacturers may sacrifice product output from disrupted manufacturing processes. For those customers with sensitive loads and technology-related businesses, power quality and even momentary outages may be a significant issue.

Minnesota Power's residential customers represent approximately thirteen percent of the Company's annual retail electric sales that are served directly from the distribution system. Interactions with these customers are similar to commercial customers, but are higher in volume and include items such as: planning for new construction, service extensions, outage restoration, system upgrades and responding to a wide variety of other electric service, program, and rate questions. Despite comprising roughly thirteen percent of the Company's annual retail electric sales, since most of Minnesota Power's retail energy sales are served via transmission-level voltage, residential customers comprise a relatively large portion of the Company's distribution system load. Additionally, much of Minnesota Power's service territory across northern and central Minnesota consists of rural communities. These rural communities and customers present unique issues when planning for investment in the distribution system. Customers located at the end of multiple miles of line on a single feeder will have different challenges and requirements than a customer located in a more populated area with feeder redundancy.

Minnesota Power continues to advance the transformation of its power supply to a cleaner energy future through its *Energy**Forward*** strategy. Since 2005, Minnesota Power has reduced carbon emissions by 50 percent and retired, idled or re-missioned 7 of its 9 coal-fired generation units, removing approximately 700 megawatts ("MW") of coal-fired generation from its 1600 MW system and making significant carbon reductions.

In early 2021, Minnesota Power filed its 2021 Integrated Resource Plan ("IRP")[3] which outlined a path towards even further carbon reduction, including steps to reach an 80 percent reduction in carbon by 2035 and a vision of being completely carbon free by 2050. The Company has reduced carbon faster than any other utility in the state and executed this transformation of its power supply while continuing to provide safe, reliable, and affordable energy for its customers.

An important aspect of *Energy**Forward*** is supporting customers in their pursuit of cleaner energy. For customers that desire higher levels of renewable energy (beyond the 50 percent provided in their current energy mix), Minnesota Power offers several different renewable options for customers, including its SolarSense rebate programs, a Community Solar Garden Pilot Program, and its Renewable Source program. Renewable Source is an easy way for customers to influence how much renewable energy is delivered to the power grid. Customers pay a premium to add renewable energy to the power grid equal to a percentage of their monthly energy use. They can choose to add 25 percent, 50 percent, 75 percent, or 100 percent. At the same time, the Company is positioning itself to provide a streamlined and supportive process for customers interested in installing Distributed Energy Resources ("DER") through the systems upgrades and expansion of its own utilization of distribution-sited resources, as discussed later in this 2021 IDP. Minnesota Power serves a variety of customer needs while balancing integration of cleaner, more decentralized energy sources.

In order to meet the needs of its unique customer base, Minnesota Power built its distribution strategy on the foundation of technology, innovation, and continuous learning. Customers expect reliable, affordable, and safe electric service, all of which are encompassed in the distribution planning strategy. Meeting these expectations requires deploying right time/right fit distribution technology that is flexible, adaptable, and upgradable. The Company has strategically positioned its distribution system for the deployment of emerging distribution technology through thoughtful planning in all areas of its business while maintaining a focus on customers' needs, upholding distribution planning principles, and aligning these investments with the Company's sustainability

[3] Docket No. E015/RP-21-33

goals. Sustainable prosperity which balances economic, environmental, and social needs, for both the Company and its customers, over the long-term is Minnesota Power's goal. Safety, integrity, environmental stewardship, employee development, and community engagement must be in the balance of every decision made and action taken.

Minnesota Power contends that sustainability – in all of its forms – plays a critical role in ensuring security, comfort, and quality of life for customers. The Company is committed to strengthening its diversity, equity, and inclusion ("DE&I") efforts. Minnesota Power is listening, engaging with others and planning specific steps toward meaningful change in workplaces and communities as the Company and its employees reckon with the social and civil unrest the nation has been witnessing, and the reverberations of generations of inequality. Specific funding for DE&I efforts will be included in the rate case Minnesota Power intends to file in the fall of 2021. Throughout 2021, Company leaders developed a framework to strengthen efforts and identified three key areas where the Company will take action: workforce, supply chain, and Minnesota Power as a community citizen.

Workforce

- Increasing staff diversity enriches the Company culture. Minnesota Power employees, like the communities the Company serves, operate in an increasingly diverse society, and its workforce needs to reflect the diversity of the communities served, promote inclusivity and be equitable.
- Actions include asking employees to respond to surveys and self-identify for a more accurate baseline demographic, live the Respect in the Workplace initiative every day, and be more intentional in furthering DE&I efforts in hiring processes.

Supply Chain

- Through investments and purchasing decisions, the Company can support diverse businesses and participate in the development of a healthier and more equitable economic system.

- Actions include identifying and expanding diverse suppliers (women-, veteran, minority-, disabled-, or LGBT-, owned businesses, HubZone, and Small Economically Disadvantaged businesses) within the supplier database, and updating the decision matrix used in purchasing decisions to include DE&I weighting.

Community Citizen

- As a leader and essential resource in its communities, Minnesota Power and the Minnesota Power Foundation have a responsibility to be responsive to the community needs through the distribution of grants. The Company strives to strengthen its ability to recognize and respond to these diverse needs in order to maintain the highest quality of life in increasingly diverse communities.
- Actions include reviewing current grant application requirements, processes and procedures, and establishing a Minnesota Power-wide corporate giving model across all business units and the Minnesota Power Foundation.

C. Providing Essential Services Throughout the COVID-19 Pandemic

Minnesota Power swiftly adapted its operations as the COVID-19 pandemic evolved over the course of 2020 and continues into 2021.[4] In March 2020, the Company voluntarily took several proactive measures to provide protections and enhance safety for employees, customers, and communities during the declared state peacetime emergency. First and foremost, Minnesota Power put numerous additional safety precautions in place, including: suspensions of all non-emergency customer site visits, avoiding direct customer contact while conducting construction and maintenance of electric facilities and equipment, eliminating all indoor work (except by specific, necessary personnel or in the case of emergency), and following appropriate Centers for Disease

[4] On March 13, 2020, Governor Tim Walz signed Emergency Executive Order 20-01, declaring a Peacetime Emergency and Coordinating Minnesota's Strategy to Protect Minnesotans from COVID-19, as most recently extended through July 14, 2021 in Emergency Executive Order 21-24, https://mn.gov/governor/assets/EO%2021-24%20Final_tcm1055-485447.pdf. Governor Walz's emergency powers ended on July 1, 2021.

Control ("CDC") and Occupational Safety and Health Administration ("OSHA") guidelines when entering homes or businesses for emergency-related services only. Currently, any customer site visits are preplanned and prescreened, and follow current CDC and OSHA guidelines.

The Company responded to COVID-19 by immediately suspending disconnections for residential customers facing financial hardship as a result of the coronavirus pandemic. Minnesota Power voluntarily extended Minnesota's Cold Weather Rule through May 31, 2020 and encouraged customers to contact the Company regarding payment plans and options that accommodate their unique financial resources and circumstances. On March 30, 2020, these measures were expanded, and the Company implemented additional protections for residential customers and new protections for commercial customers, including: waiving late payment charges for residential and small business (general service) customers, suspending disconnections for small business (general service) customers facing financial hardship in relation to the coronavirus pandemic; and waiving reconnection fees during normal business hours for residential and small business (general service) customers previously disconnected for non-payment.

In its August 13, 2020 Order under Docket No. E,G-999/CI-20-375, the Commission formally ordered suspension of disconnections for residential customers; suspension of negative reporting to credit agencies for residential customers; and waiving reconnection, service deposits, late fees, interest, and penalties for residential customers. Per the Commission's August 13, 2020 Order, these protections are to remain in effect for the duration of the peacetime emergency with 60 days' notice before resuming these activities. In the Commission's May 26, 2021 Order, the Commission adopted a modified Consumer Advocates' Transition Plan, and allowed for the resumption of disconnections on August 2, 2021. In addition, while field activities related to customer collections were suspended, Minnesota Power redeployed field staff to focus on advanced metering infrastructure ("AMI") installations.

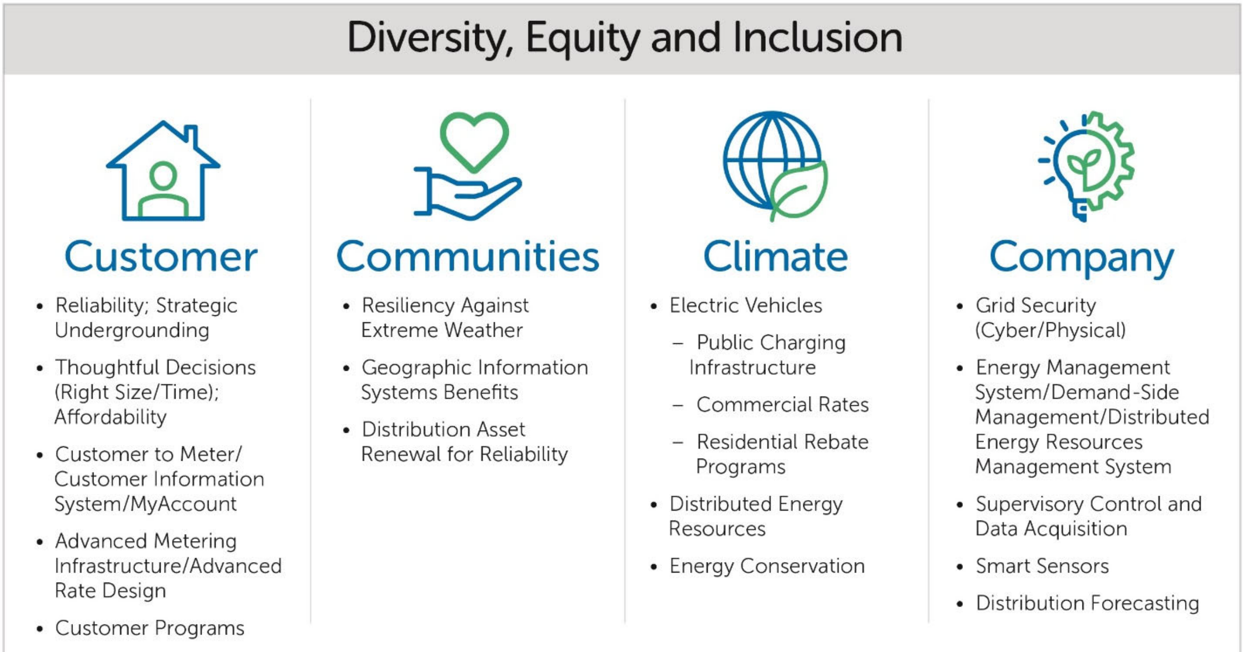
As approved in the Commission's May 5, 2021 Notice of Amended Transition Plan Completeness and it its May 26, 2021 Order, Minnesota resumed normal operations by way of disconnection notices starting in June, 2021 and reinstatement of service disconnections for non-payment on or after August 2, 2021. Some protections remain in place for the duration of the transition period, which ends April 30, 2022.

The Company continues to be impacted by the COVID-19 pandemic in its day-to-day operations. One aspect is supply chain disruptions which include unexpected, significant increases in commodity prices and lengthy delays in material delivery times. The Company has been proactively finding creative ways to address these impacts, including working with neighboring utilities, communicating with customers, and working diligently with vendors and suppliers to identify new options and plan for longer lead times.

D. Sustainability Holistically Considers the Customer, Community, Climate and Company

Minnesota Power's *Energy**Forward*** strategy outlines a vision for a sustainable future for the customer, community, climate, and company. The Company's 2021 IDP considers each of these important perspectives, as depicted in Figure 3. Minnesota Power is planning for the future of an advanced grid while also enhancing the customer experience. The Company's 10-year long-term plan focuses on continued investment in infrastructure with accelerated investments in the near-term in systems and data to optimize the 21st Century power grid. Investments in data and applications will provide a greatly enhanced customer experience while enabling key operational benefits for reliability and safety.

Figure 3: 2021 IDP Key Themes



1. Customer: *Enhancing the Customer Experience*

As Minnesota Power plans for a future grid, the Company will remain customer-focused; continuously improving the customer experience, building relationships, improving reliability, and ensuring consumer benefits. The Company continually strives to maintain and build relationships with its various customer groups. Minnesota Power's approach to customer service is to continue to provide the core services customers count on as effectively as possible, while leveraging technological advances where applicable and practical to meet the modern day needs of customers. The Company recognizes that, above all else, customers expect reliable, affordable, and safe electric service. Inherent to each of these is convenience, transparency and timeliness of service interruption updates, as well as clarity with respect to costs and program offerings. However, in order to meet these customer needs, the Company must ensure the right resources are working on the right priorities at the right time. Part of enhancing the customer experience will be making thoughtful decisions around investment priorities while attracting and aligning talent with the changing customer, technology, data and analytics needs of the industry.

Today, Minnesota Power is continuously improving the customer experience through the company's online tools, programs and services, and steady support from its Customer Care and Support team. Minnesota Power currently incorporates customer insights gained from customer interactions, satisfaction surveys, and benchmarking tools along with industry best practices to ensure energy solutions meet the needs and expectations of customers today and into the future. Customers will serve an increasingly interactive role in helping to maintain reliability of the system, particularly during peak demand periods and as variable renewable energy sources become a growing part of the energy mix. The Energy Conservation and Optimization Act of 2021 ("ECO Act") policy provisions passed during the 2021 legislative session[5] provide a timely pathway for building on core conservation program offerings and expanding those to include cost-effective fuel switching and load management options. While there are technical and process guidelines that must be developed to effectuate the policy objectives of ECO Act, load management has been identified as an important part of utility program offerings going forward. This has a direct relationship with distribution planning and related investments.

Rapp Strategies recently managed a customer survey project for Minnesota Power. They contracted with Morris Leatherman Company to survey 800 residential customers, a sample that accurately reflected the actual residential customer base in key demographic areas. The customers surveyed indicated a primary preference for reliable, safe, and affordable electricity.

The survey identified that approximately one-third of the customers surveyed engage with the Minnesota Power website and approximately 20 percent utilize the Minnesota Power app. Amongst the customers that use these communication and engagement channels, there was a very high level of satisfaction with over 95 percent rating them good or excellent, and most were utilizing the platforms to engage in billing and payment. These digital platforms are important for customers to access their bill, make payments, review energy use, and to report and monitor outage communications.

[5] Minn. Stat. §§ 216B.2401, 216B.241, as affected by law enacted during the 2021 Regular Session

As a result of the Company's engagement in other industry forums, Minnesota Power was aware that it is above average with respect to overall customer satisfaction and the importance customers place upon digital channels for billing, payment, energy usage, and outage communication. The Company has therefore taken steps to improve payment options and enhance digital platforms for customer interaction. Minnesota Power has made significant progress in digital platforms that support customers that prefer digital channels, whether through the MyAccount portal, mobile app, or launching of the no-fee credit or debit card bill pay option, as approved in the 2016 Rate Case.[6]

2. Community: *Planning a More Resilient Grid to Ensure Reliability*

Planning for a reliable and resilient power supply to communities as they experience increased extreme weather events is a critical part of Minnesota Power's distribution planning process. This 2021 IDP will detail a number of efforts aimed at planning for a more resilient grid to ensure reliability for communities, including efforts like asset renewal investments, strategic undergrounding, grid modernization efforts, and more. Partnerships with the communities it serves will be a critical component as Minnesota Power continues its state-leading carbon reduction journey towards a path of a 100 percent carbon free energy supply by 2050.

As an example of this community engagement, Minnesota Power held a virtual stakeholder forum on July 13, 2021 using WebEx. The goal of this forum was to educate stakeholders on the Company's past and current distribution initiatives, distribution planning processes, share the contents of the 2021 IDP, and to gain stakeholder feedback to incorporate into the filing.

During the forum, Minnesota Power presented information regarding the following: Minnesota Power and its distribution system; the purpose and elements of an IDP; DER resources and DER scenarios; foundational investments, including the 5 and 10-year investment plans; demonstrated innovation, modernization investments, and systems. The Company also presented on how it is planning for a resilient future, including reliability target areas. Interest from stakeholders at the meeting included topics around the 5-year

[6] Docket No. E015/GR-16-664

investment plan, geographic information system ("GIS") mapping, and recloser technology. Information on the topics stakeholders raised during the meeting have been included in this filing.

The materials from the July 13, 2021 stakeholder meeting can be found in Appendix B. Due to the innovative nature of the IDP filings, ongoing education and iterative dialogue with stakeholders will be crucial during the development of further/refined IDP requirements and corresponding information communicated by the Company. The Company is dedicated to continuing these valuable conversations with its stakeholders.

3. Climate: *Optimizing the Grid for Demand Side Resources and Electrification*

As Minnesota Power advances towards its carbon-free vision, the Company will focus on right time/right fit investments, operational efficiencies, and reliability/resiliency upgrades to ensure a modern grid can continue to support the Company's Energy***Forward*** strategy. The systems implementation timeline communicated through this 2021 IDP seamlessly integrates current customer systems, asset management, and operational systems under one real-time Utility Network model. This secure end-to-end system model will integrate all of Minnesota Power's generation sources, transmission infrastructure, and distributed assets and resources. This model will reside within a flexible, adaptable, and upgradable platform which will aid the Company to grow and respond to utility system dynamics and meet public policy goals. It will allow for a streamlined data gathering process to provide meaningful and proper data sets for stakeholders and the Company which will be utilized to advance a customer-centric, modern grid.

As technology continues to evolve, there is a growing desire on behalf of customers for more individualized services that include renewable or lower carbon options. Customers are interested in products and services that increase accessibility to energy conservation programs, renewable energy and electrification. While the Company's current portfolio includes 50 percent renewable resources, some customers want even more of their energy supplied from renewable sources. As the Company plans for a distribution system of the future, accommodating customer desires on efficiency, renewable energy and electrification is critical. These assumptions and programs are reflected in the 2021 IDP.

4. Company: *Securing the Grid of the Future*

Minnesota Power has been an active participant in industry associations, workgroups and Commission dockets that address grid security and data privacy issues. For example, the Company is currently an active participant in Docket E999/CI-20-800, In the Matter of a Commission Investigation on Grid and Customer Security Issues. As the future grid evolves to accommodate new technology, new resources and new systems, security of the grid will be critical to ensuring the utility can continue to deliver essential services to customers.

The electric grid continues to evolve to meet increased demands from new technology, customers and weather, and it is imperative that both the physical and cyber security of the system be maintained. Minnesota Power is investing in systems described in the following section that not only meet the needs of customers but ensure the distribution system is able to operate efficiently and securely.

E. Overview of Minnesota Power's Current Systems

The following sections provide a brief overview of each system critical to the operation of the Company's distribution system. All existing and new systems are necessary regardless of this distribution plan, and the Company would not attribute the costs of obtaining data from these systems to this plan. However, the systems below provide a robust basis for developing the system data necessary for future distribution planning, such as Photovoltaic ("PV") output profiles, Demand Response ("DR") products and profiles, and Electric Vehicle ("EV") charging profiles. Costs associated with developing this information is not quantifiable at this time.

1. Customer Focused Systems Overview

Investments in Customer Systems have been driven by customer desire for more convenient and diverse products and services, including self-service electronic communication options and services; and information about energy and product offerings, generally through efficiency and pricing or a combination of the two. Minnesota Power's approach is to continue to provide the core services customers count on as effectively as possible, leveraging technology advances where applicable and practical. To meet customers' needs, the Company must continually invest in new technologies and customer-facing improvements. For example, two short-term goals include the Customer to Meter ("C2M") project that introduced the implementation of a meter data management system to further leverage Advanced Metering Infrastructure deployment and enhancements of customer self-service through the Company's MyAccount tool, both of which will improve customer service as well as distribution system intelligence.

The systems upgrades and implementations outlined in this section are part of a holistic C2M solution which involves upgrading the existing Customer Information System ("CIS") to an Advanced Meter Billing System that includes the following modules: Customer Information Billing and Rates, Meter Data Management ("MDM"), Smart Grid Gateway, Meter Asset Management, and Service Order Management. More on the C2M project can be found in Section II.D.4 – Customer to Meter Project.

Customer Information System – The core customer information system is designed to securely store customer information and act as the primary billing and rate engine for Minnesota Power customers. This system was upgraded in 2021 as part of the C2M project, which has enabled additional functionality through the specialized modules that were deployed in the overall system. This has and will continually enhance automation and provide greater accuracy of presented customer information.

Meter Data Management – The MDM was implemented as part of the C2M project, and is the cross-cutting system that provides a data engine that performs Validation, Editing, Estimating, and organized storage ("VEE") of both rate and operational information from metering systems. Metering systems include the Advanced Metering

Infrastructure, Automated Meter Reading, and interconnected and industrial meters. This investment will provide greater consistency and accuracy with customer billing and organized operational data for system sharing. This system was installed in April 2021, and will continued to be optimized for billing and rates through 2021.

MyAccount – This online portal allows customers to view and pay bills, look at and track daily and hourly usage, request a stop, start or transfer of service, and perform other account functions. This tool will continue to be enhanced through modest, meaningful investment annually over the next 10 years and will leverage customer data provided by the underlying customer systems. As well as maintaining its initial purpose of providing customers with consumption and usage data to make informed energy decisions and increase energy efficiency, additional functionality was deployed to provide customers with the ability to view their bills and make payments on-line. In addition, this tool is accessible through the Minnesota Power app where customers can view and report outage information.

Over the next 5 to 10 years, Minnesota Power's strategy is to continue MyAccount upgrades and expand deployment with smaller investments, such as a Customer Preference Center, streamlined payment options, personalized program recommendations, and proactive alerts. The Customer Preference Center will be expanded in 2021-2022 to become the central repository for customer communication channel preference information for notifications related to outages, billing, programs and services.

Automated Meter Reading ("AMR") – AMR is the legacy metering system that was installed at Minnesota Power from 2002-2006 utilizing first generation power line carrier technology. The system is very effective at one-way acquisition of meter reads but has limited bandwidth for supporting complex rates or real-time data capabilities. In 2009, the manufacturer deemed the system obsolete and, as a result, that system has been self-supported by Minnesota Power since 2011. The current strategy is to fully replace this system by 2023 with the Advanced Metering Infrastructure system.

Advanced Metering Infrastructure ("AMI") – AMI is an advanced, two way metering system that provides metering, operational, and real-time notification of system conditions at customer premises for virtually all retail residential and commercial customers. AMI has the ability to enable advanced Time-of-Use ("TOU") rates when combined with a MDM. The current AMI system is scheduled to be fully deployed by 2023 and includes further integration with other, cross-cutting systems. See further info in Section II.F.2 – AMI.

Meter Asset Management – The Meter Asset Management module was implemented as part of the C2M project. The purpose of this module is to enable the storage of specific attributes related to AMI meters. Due to the specific requirements related to AMI meters (firmware management, TOU schedules, load/voltage profile structure, etc.) and specific rate data associated with managing AMI assets, Minnesota Power strategically included this additional functionality with the C2M implementation. This system will provide the appropriate level of information to automate some of the commands and AMI system features out of the billing system and allow for verification of meter configuration and readiness for specific rates within the MDM system.

Smart Grid Gateway ("SGG") – SGG was implemented as part of the C2M project. In addition to Meter Asset Management, the SGG is another system that is designed to optimize the AMI system by providing an automation engine. This system utilizes capabilities through standard data models within the AMI system to allow for expansive integrations with other systems. The SGG is what enables the MDM to talk to head-end metering systems.

Mobile Workforce – Minnesota Power began accelerating the use of Mobile Workforce starting in 2017, with the first phase focused on interfacing with CIS field orders for Metering and Collections. This first phase has created paperless processing for nearly 30,000 customer orders annually. The second phase--which started in late 2018 and went live in 2019--focused on bringing trouble tickets from the Outage Management System ("OMS") into the Mobile Workforce application. This will allow an additional 4,000 tickets annually to be processed electronically within that application. A third phase of the program, deployed in 2021, focused on the integration of work and asset management systems as well as C2M. Enhancing mobility to field workers will continue to advance as opportunities arise. As specific examples, the recent deployment of a mobile Engineering Design tool as well as additional considerations for electronic work packets and inspection rounds.

Outage Management System – The current OMS system contains all reports of power outages and predicts the failed equipment and fault location related to outages reported on the system. It is the source for all customer-facing outage data and provides record of all outages and trouble orders for regulatory reporting. This system is slated for replacement in 2021-2023, as upgrades have become onerous with declining software support. Currently, customers are able to view and report outage information through the Minnesota Power app. More information on the OMS system can be found in Section II.D – Infrastructure 5-year Investment Plan.

2. Operational Systems Overview

Geographic Information Systems/Utility Network Model – Minnesota Power has utilized GIS for close to 30 years. Many operational systems at the Company reference or utilize the GIS system to provide geographical and spatial aspects to operational data. In 2020, Minnesota Power began to move to a next generation GIS system which will integrate asset models from Generation, Transmission, and Distribution systems to create a real-time Utility Network model. This Utility Network model will continue to be interconnected to Company systems and have the accuracy to be compartmentalized and utilized securely for customer, internal, and stakeholder applications. The future GIS system will be transformed into an integral geographic and spatial base that will allow for maximum effectiveness and efficiency when implementing new systems and sharing information. More information on the use of GIS can be found in the Section II.D – Infrastructure 5-year Investment Plan.

Energy Management System ("EMS")/ Distribution Management System ("DMS")/ Distributed Energy Resource Management System ("DERMS") – Minnesota Power has been utilizing an EMS for nearly 40 years. Over that time, the capabilities and the system model of the EMS have been continually expanded and optimized to meet Minnesota Power's needs. The current version of EMS combines transmission operations and high capacity distribution substations to provide situational awareness and remote switching of equipment. The development plan for this system is to perform requirements gathering for full DMS capability as communication options and automation are expanded into the distribution system that will enable new capabilities such as fault location, isolation, and system restoration ("FLISR"), volt/VAR optimization ("VVO") and conservation voltage reduction ("CVR"). Future system requirements will be determined in the 2023-2024 time frame as the Company plans for the next generation of the system. Currently, DER is not actively managed through EMS, however, small distribution-connected solar is monitored with the AMI system while larger solar (greater than 1MW) is centrally monitored and reported within EMS. Minnesota Power does not currently have a significant amount of solar connected to the distribution system, so no DERMS is necessary at this time. Nonetheless, DER growth will be monitored and the system tailored as the need for control arises within different aspects of the Company's distribution system.

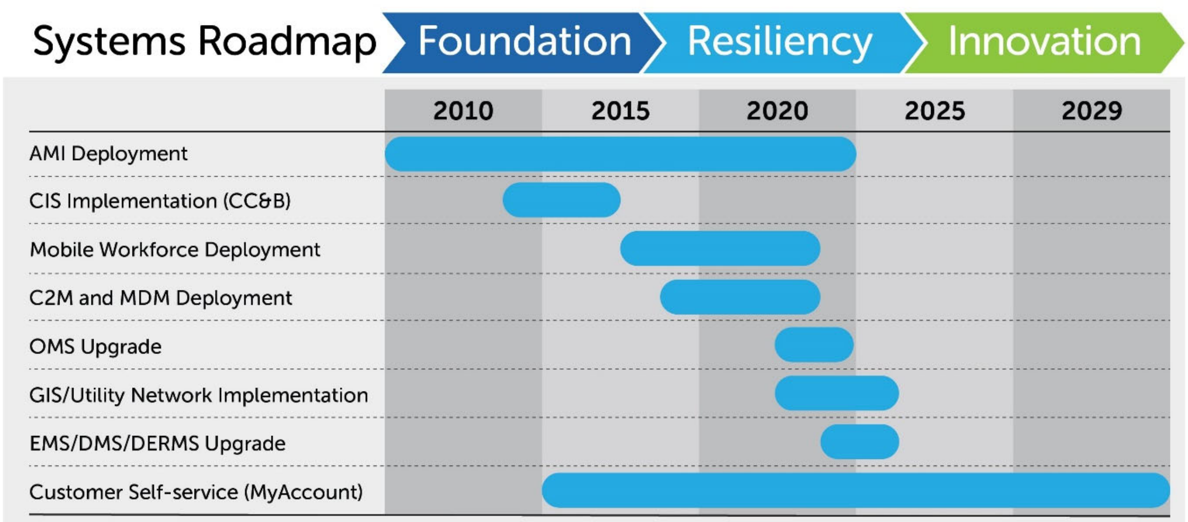
Infrastructure/Distribution Asset Management – Minnesota Power has developed a plan to modernize the system and ensure reliability of service. With many assets 40+ years old, asset management programs and investments have increasingly become an area of significant focus for Minnesota Power. Asset renewal programs have been bolstered in recent years in an effort to target areas known to impact customer reliability and system resiliency. Minnesota Power has taken a strategic approach targeting key feeder and substation connected assets. At the substation level, previously unconnected asset renewal programs have been integrated into a single substation modernization program designed to efficiently and holistically address all of the asset renewal needs at a site with one comprehensive project.

Along with these asset renewal strategies, Minnesota Power has been developing its preventative maintenance and emergency replacement programs to track and enhance the health and reliability of its distribution assets. These systems are in the process of being optimized to support Minnesota Power's long-term utility asset management needs. The backbone of a healthy distribution system is communication and system management. They work in conjunction with each other to improve how information is provided and gathered, resulting in more accurate restoration times, outage statistics, and improved usability. Together, these systems allow the Company to more readily implement a future DERMS and/or an Advanced Distribution Management System ("ADMS") to control widespread use of solar and other distributed generation ("DG") sources as needed.

3. Systems Implementation Timeline

In order to facilitate advancement towards a modernized grid and customer experience, the Company is implementing a foundational systems strategy as communicated in Figure 4. The system implementations are the building blocks for innovative programming, reliability-focused grid modernization improvements, and a smooth transition to a future with higher DER penetration. Each of these systems upgrades are discussed in detail in Section II.D - Infrastructure 5-Year Investment Plan.

Figure 4: Systems Implementation



SECTION II:

Current DER Programming and Foundational Investments

II. CURRENT DER PROGRAMMING AND FOUNDATIONAL INVESTMENTS

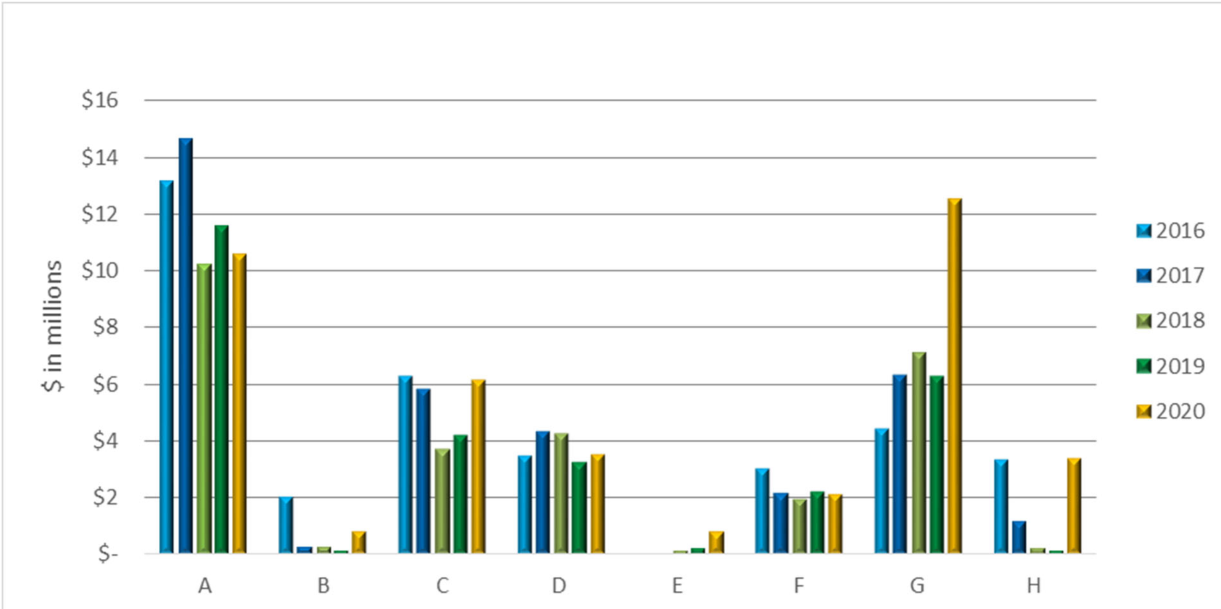
Minnesota Power has been operating and maintaining its distribution system for many decades to serve customers in Northeast Minnesota to ensure they have access to safe, reliable and affordable service. Minnesota Power has traditionally followed a depreciation level spending pattern for its distribution system. The historical annual expenditures depicted in Figure 5 reflect depreciation level spend. Budgets are adjusted annually due to meet internal and external customer needs including government-mandated projects, age-related replacements, metering advancement and asset renewal programs, among others. Foundational investments focused on traditional system improvements and often resulted in upgrades made to underperforming areas.

The foundational investments outlined in this 2021 IDP are not only accommodating the current needs of the system, but are also positioning the Company for a transition to an innovative future. Going forward, Minnesota Power is increasing its investments above depreciation level spend to accelerate asset renewal, modernization and reliability projects as communicated in Section IV – Planning for a Resilient Future. This section will include information on the Company's current DER programming, modernization investments, its five year investment plan, current projects, an analysis of system data, communication strategy and cyber security efforts.

Table 1: Historical Distribution Spending

Planned Distribution Capital Investments by Category	2016	2017	2018	2019	2020
A - Age Related & Asset Renewal	13.127	14.636	10.226	11.580	10.552
B – Capacity	2.045	0.248	0.267	0.124	0.805
C - Reliability & Power Quality	6.260	5.842	3.717	4.200	6.139
D - New Customer / New Revenue	3.469	4.333	4.242	3.252	3.504
E - Grid Modernization & Pilot Projects	0.010	0.005	0.152	0.237	0.815
F - Government Requirements	3.023	2.185	1.938	2.201	2.120
G – Metering	4.404	6.327	7.107	6.255	12.523
H – Other	3.323	1.167	0.207	0.151	3.376
Total ($ in Millions)	**$35.661**	**$34.743**	**$27.856**	**$28.000**	**$39.834**

Figure 5: Historical Distribution System Spending, by category



A. Current DER Programming and Background

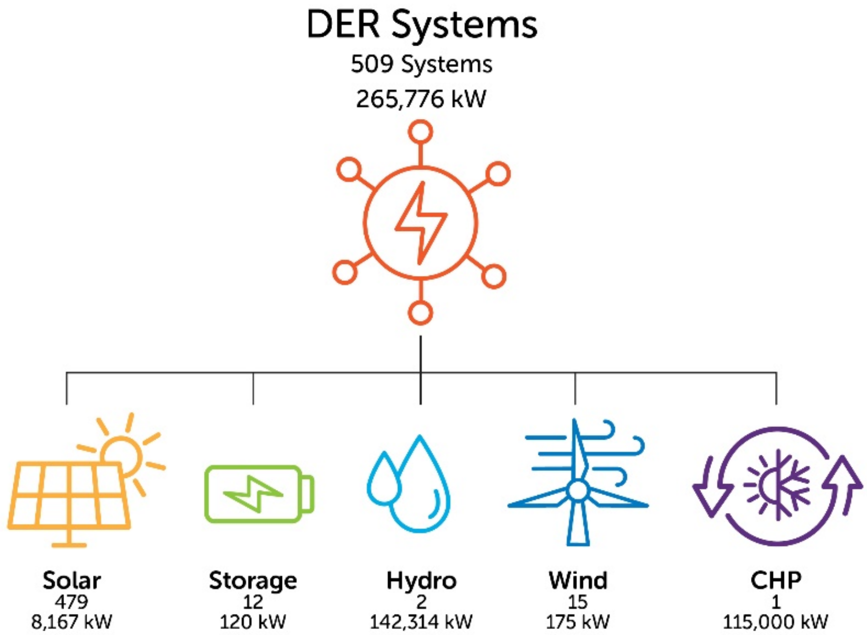
Minnesota Power has a longstanding history of working collaboratively with its customers as they implement DER. The Company is continuously monitoring the emerging trends of DER technology, both nationally and locally, along with its customer requirements. By enhancing customer communication efforts, Minnesota Power is helping to align customer expectations with achieved results. These efforts will aid in ensuring that DERs continue to be installed in a safe, reliable, and effective manner in Minnesota Power's service territory.

1. DER Systems

At the end of 2020, Minnesota Power had 509 registered DER systems[7] as depicted in Figure 6. The majority of DER systems on Minnesota's Power's system are distributed solar. This represents a fairly diffuse penetration of DER on the system as a whole, but there are a few concentrated areas worth noting as outlined in Section IV.C.6 - IEEE Std. 1547-2018 Impacts. The Company's DER forecasting and analysis can be found in Section IV.C – Distribution Forecasting.

[7] Docket No. E999/PR-21-9

Figure 6: Current DER Systems



2. Demand Response

Minnesota Power leads the state in the amount of DR as a percentage of peak demand, with 250 MW[8] of Midcontinent Independent System Operator ("MISO") accredited DR from the Company's large industrial customers[9] representing approximately 15 percent of peak demand.[10] In addition to DR programs for its largest customers, Minnesota Power offers a Dual Fuel rate that allows the Company to curtail mainly heating load of approximately 8,000 residential, commercial, and small industrial customers during times of high market energy prices or a system emergency. Participating customers must have a non-electric back-up energy source. Since this program deals almost exclusively with electric heat, there is minimal load to curtail in summer months - approximately 4 MW, mostly from commercial/industrial loads. The available curtailable load in winter months depends on temperature and heating loads,

[8] Planning Year 2021-2022 is 250 MW of capability. Actual Zonal Resource Credits received was 292 MWh, which is adjusted for transmission losses and MISO Planning Reserve Margin.
[9] These customers are transmission-connected, and not served by Minnesota Power's distribution system
[10] Minnesota Power's most recent seasonal peak (2/5/2021) was 1,646 MW

mostly of residential customers, but can deliver demand response of approximately 30 MW, or approximately 2 percent of the winter peak load.

3. Electric Vehicles/Beneficial Electrification

Minnesota Power monitors both publicly available data and participation in programs and tariffs to gauge customer adoption rates of EVs. The Company estimates there are about 330 light duty EVs (i.e. passenger vehicles) in Minnesota Power's retail service territory.[11] This equates to a 0.17 percent penetration rate, meaning approximately 3 percent of households own an EV (on average). According to the Department of Energy's Alternative Fuels Data Center, there are 36 public EV charging stations in Minnesota Power's service territory, with 84 connectors ranging from level 2 to level 3. The total capacity of these chargers is estimated to be about 1.2 MW.[12] Additionally, there are currently seven residential customers enrolled in the Company's Off-Peak Residential Electric Vehicle rate and four customers enrolled in the Commercial Electric Vehicle Charging rate.

Barriers to adoption, including range anxiety (especially in cold weather), lack of public charging infrastructure, and the upfront cost of the vehicle continue to prevent many consumers from purchasing an electric vehicle. Minnesota Power has developed several EV programs and offerings designed to address these barriers, including rebates for home charging equipment, a smart charging rewards program, residential and commercial EV charging rates, and an EV education and outreach program. Minnesota Power recognizes that access to reliable EV charging infrastructure is a major barrier to electric vehicle adoption in northern Minnesota and as such, the Company submitted a proposal to install 16 direct current fast charging ("DCFC") stations throughout its service territory on April 8, 2021.[13] Through the proposal, which was approved by the Commission during its September 23, 2021 agenda meeting, the Company aims to advance an equitable distribution of these charging stations in order to provide access to EV users in rural population centers and travel corridors throughout the Minnesota Power

[11] Estimate for October 2021
[12] https://adfc.energy.gov/stations
[13] Docket No. E015/M-21-257

service area. Additionally, these programs and offerings all include components intended to encourage efficient charging behaviors through time-based rate/incentive structures or promotion of enabling technology like smart chargers.

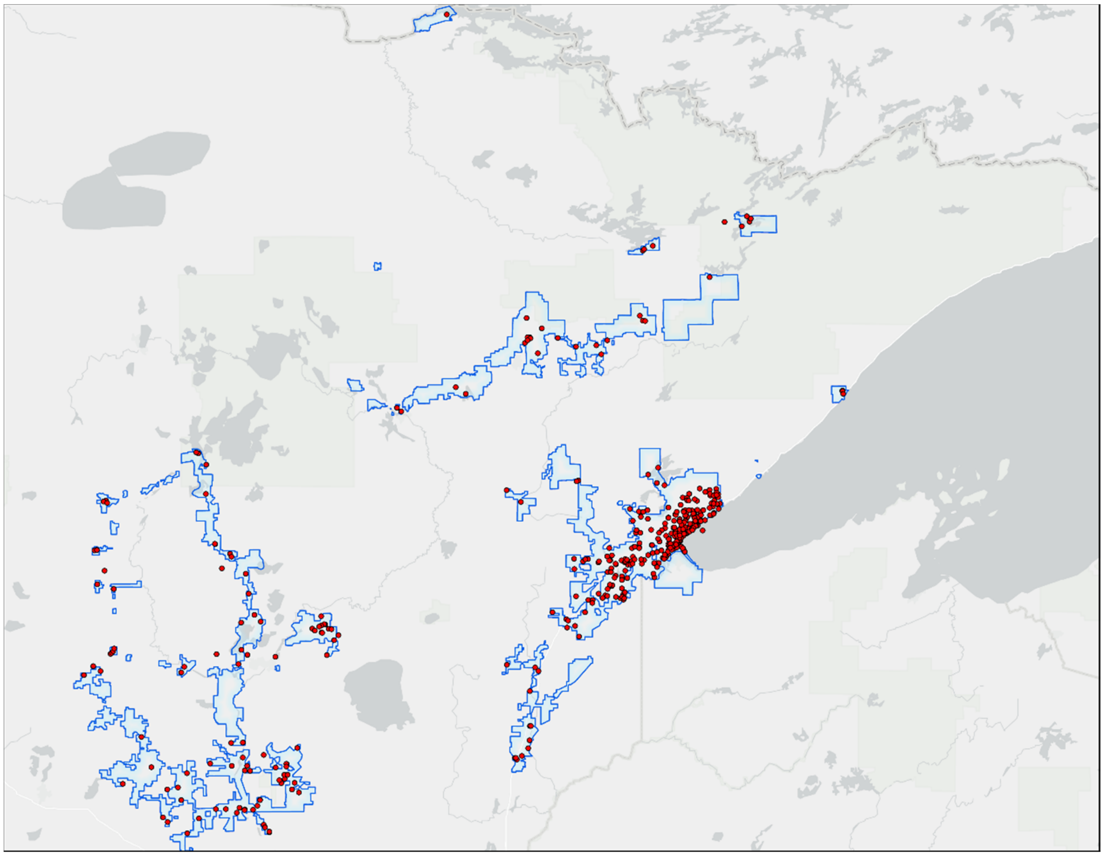
The Company anticipates declining upfront costs for EVs as the secondary market grows and new models continue to emerge. Minnesota Power will continue to explore best practice options for alleviating customer barriers and encouraging responsible growth of the EV market from a power supply perspective for all customer classes. At the same time, the Company continues to advance its own internal EV strategy for Minnesota Power fleet vehicles.

4. Small-Scale Solar

Following the passage of the Minnesota Solar Energy Standard ("SES"), Minnesota Power developed a thoughtful solar strategy that included activities balanced across three key pillars: Utility, Community, and Customer. Minnesota Power continues to believe that solar investments at the utility scale can create efficiencies and cost savings through economies of scale, but partnering with the community and providing individuals with options for customer-sited solar are equally important. With thorough planning and proactive action in each area of the Company's solar strategy, Minnesota Power has successfully met the requirements of the SES.

In terms of the Customer pillar of Minnesota Power's solar strategy, the Company continues to support customer-sited solar systems through the SolarSense Program. The majority of DER on Minnesota Power's system are distributed solar installations. Figure 7 shows these solar installations are highly concentrated in and around Duluth, but are also scattered throughout Minnesota Power's system.

Figure 7: Customer Sited Solar

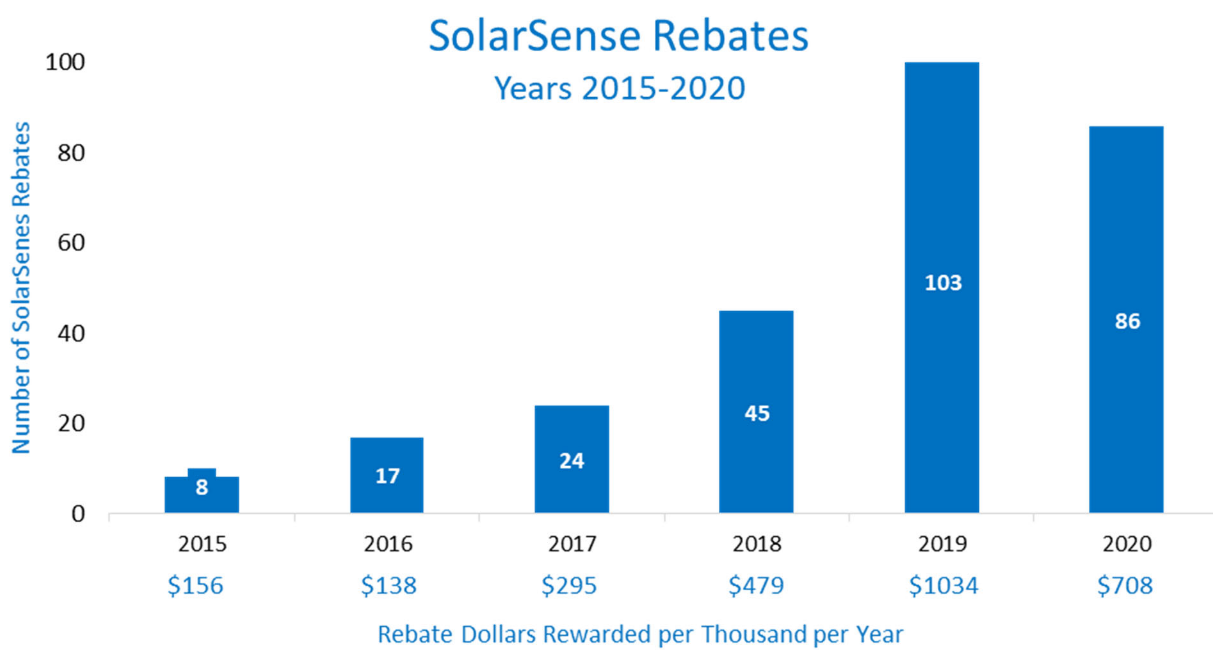


Minnesota Power's SolarSense rebate program encouraged a large number of these solar installations. The program has been in place since 2004, well before Minnesota's SES was passed,[14] and was expanded significantly in 2017 as a means of compliance with the SES. Over the past 14 years, Minnesota Power has supported roughly 365 solar installations totaling over $3.6 million in rebates. Effective 2021 through 2024, largely due to the success of the SolarSense program, adjusted rebate budgets were approved by the Commission on December 17, 2020 in Docket No. E015/M-20-607, as well as a yearly grant budget of $120,000 (an increase from $60,000) to focus on Low-Income Solar opportunities through the Low Income Solar Grant Program. The Low Income Solar Grant Program is a first of its kind program in Minnesota, designed to increase accessibility of solar energy to low-income customers. More information on that program can be found in Section III.A.2 – SolarSense Low-Income Solar Pilot.

[14] Minn. Stat. § 216B.1691 Subd 2(f)

As highlighted in Figure 8, installations have varied greatly year-over-year depending on available incentive funding. While rebated installations have varied year over year, an increasing number of solar projects are moving forward without an incentive from the Company as solar costs continue to decline. For further information please see Appendix C.

Figure 8: SolarSense Rebates



Per Minnesota Power's Distributed Generation Interconnection Report filed in Docket No. E999/PR-21-10 on February 26, 2021, 92 distributed generation systems were interconnected in 2020. Of those installations, 84 customers reported an installation cost before incentives amounting to a total of $3,376,259 including $2,418,766 for residential systems, $767,493 for commercial systems and $190,000 for customer community solar project. During that same time period, non-Minnesota Power investments in distribution system upgrades required as a condition of customer-sited solar interconnections amounted to $7,720. Additionally, Minnesota Power began charging an application fee for all applicable solar installations on June 17, 2019 in accordance with the State of Minnesota Distributed Generation Interconnection Process

(“MN-DIP”). The Company collected application fees from 83 customers totaling $8,516 dollars in 2020.

5. Conservation Improvement Program

Minnesota Power is proud of its state-leading conservation program, which has surpassed the state energy efficiency goal of 1.5 percent year after year since the goal’s inception in 2010. Between 2013 and 2020, Minnesota Power achieved an average of 73 gigawatt hours (“GWh”) in incremental (i.e. first year) annual energy savings, with achievements ranging from 64 GWh to 85 GWh through its Conservation Improvement Program (“CIP”) (Table 2). The Company had a savings total of more than 70 GWh in 2020. That is enough energy to power 8,000 homes and avoid 55,000 tons of carbon emissions per year; the equivalent of taking 11,000 cars off the road.

Prior to 2017, Minnesota Power reported demand savings coincident with Minnesota Power’s system peak, which typically occurs in the winter. Between 2013 and 2016, peak demand savings resulting from the CIP programs ranged from 6 MW to 9 MW. Beginning in 2017, the Company was required to start reporting peak demand savings from CIP coincident with the MISO system peak, which typically occurs in the summer. The average peak demand savings reported for 2017 through 2020 was 8.0 MW.[15] Both energy and demand savings are determined based on State-approved calculations and methodologies for preapproved energy efficiency measures.

[15] The Company’s Demand Side Management (“DSM”) program provides end use load shapes. The load shapes developed through this program aid in determining the avoided marginal energy benefits of energy efficiency achievements.

Table 2: Average Total Savings

	Reported MW savings at the generator	Total MWh Savings	Percentage Savings
2013	2.72	77,631	2.5 percent
2014	9.22	76,338	2.5 percent
2015	7.23	85,611	2.8 percent
2016	9.49	64,034	2.1 percent
2017	8.59	72,372	2.6 percent
2018	8.10	72,480	2.6 percent
2019	8.34	67,669	2.5 percent
2020	6.81	70,774	2.6 percent
		Average Total Savings:	73,364

As referenced in Section I.D., the ECO Act passed during the 2021 legislative session seeks to build upon energy efficiency offerings to include cost-effective load management and fuel switching. This will provide opportunities for broader program offerings going forward.

B. Modernization Investments

The keys to successful modernization investments are detailed planning, project execution plans, project metrics, cost, and anticipated vs. actual benefits. Minnesota Power's approach to modernization has been to target pilot-scale projects that incorporate optionality and scalability. This approach has yielded benefits, including improved integration of DER, as a result of both Operational Technology ("OT") and Information Technology ("IT") investments that speed the process of interconnection to the distribution system.

Modernization investments are made with a continued focus on safety, reliability and affordability. Most modernization improvements begin with data-based analysis that has been collected through the Company's information management systems. The capital utilized in modernization activities can generally be broken down into two specific categories:

- Operational Technology – Replacement of existing assets with modern asset designs that incorporate solid state components, sensors and communication technology to provide visibility, connectivity and data streams to system operations (i.e. AMI, voltage monitors, intelligent switches, or sensors) that are integrated with centralized software and control systems.

- Information Technology– Software and OT interface investments that allow for storage, reporting, control and utilization of data and information in operations.

These technology investments, combined with a customer-centric outlook, allow for prudent system evaluation based on an ever-expanding foundation of data and information. This data provides more confidence in load research, modeling and forecasting. The data can be used in rate design, class cost of service studies, targeted conservation and demand response, new product offerings, etc.

C. Interconnection Process Changes

Over the past few years, Minnesota Power has worked with the Distribution Generation Working Group ("DGWG") to update the MN-DIP process and compile technical standards that apply to various different types of interconnections. In general, the MN-DIP process has been a positive change for Minnesota Power and its customers. Most of Minnesota Power's interconnections are a result of the SolarSense program, a rebate program for small-scale solar that customers can participate in to offset solar costs. To date, most of the applications processed are quite small, as the program cap is 40 kW.

In July of 2020, the Minnesota Technical Interconnection and Interoperability Requirement ("TIIR") went into partial effect. The TIIR outlines DER interconnection requirements that are common across all Minnesota utilities. In addition to the TIIR, each utility developed their own Technical Specification Manual ("TSM") in which specific standards were outlined for new interconnection. While the TSM formalized some previous standards that couldn't be easily found in one place, most of the requirements for DER already existed.

The primary changes in Minnesota Power's standards were requiring a default 0.98 absorbing power factor for inverter-based generation and the updates surrounding remote monitoring and telemetry. Minnesota Power now requires all DER with a nameplate capacity of 250 kW or greater to be remotely monitored so that these systems can be incorporated into EMS (and eventually ADMS) models. Monitoring these larger installations will be crucial as DER penetrations increase and more visibility is required to safely operate the system. The move to a 0.98 absorbing power factor was common across all utilities and was made to increase potential penetration levels on the distribution system. So far the changes have been well-received, although Minnesota Power has had no external interconnections greater than 250 kW since July 2020.

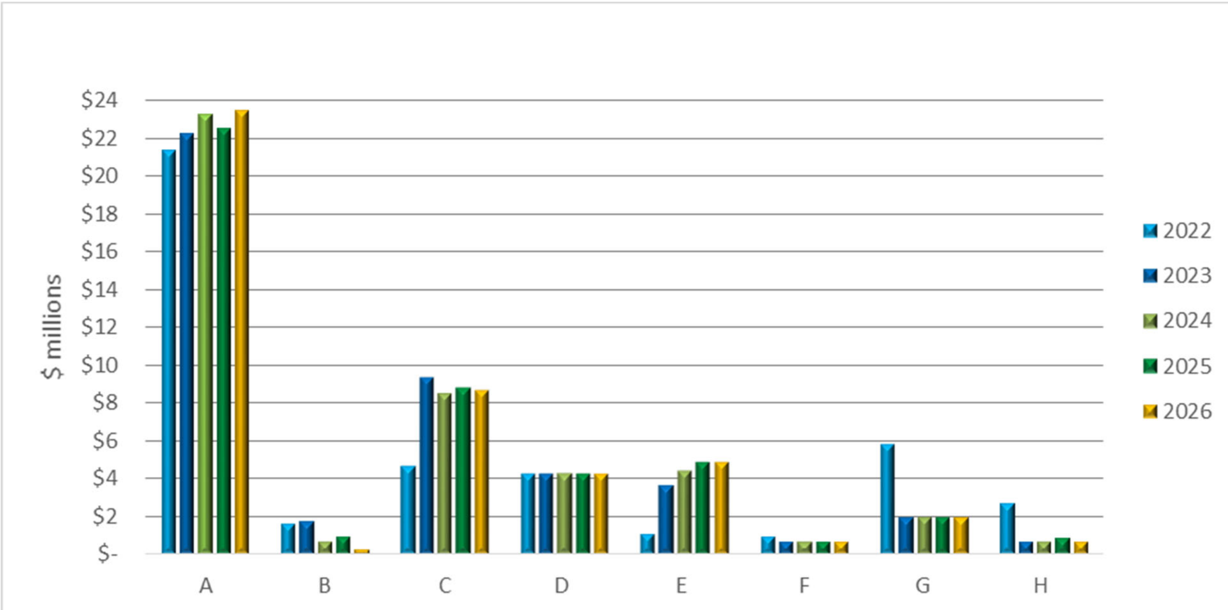
D. Infrastructure 5-Year Investment Plan

The 5-Year investment Plan includes a number of strategic projects in the Company's distribution capital budget and includes an increase in spend for key budget areas, as outlined in Figure 9. These are identified as part of broader strategic Minnesota Power initiatives that most often directly benefit the Company's customers. An example of a strategic project would be the Company's deployment of AMI, a multi-year concerted effort discussed in Section II.F.2 and other areas throughout the 2021 IDP.

Table 3: Five Year Future Investments (by category)

Planned Distribution Capital Investments by Category	2022	2023	2024	2025	2026
A - Age Related & Asset Renewal	21.322	22.215	23.283	22.493	23.438
B - Capacity	1.600	1.740	0.653	0.958	0.268
C - Reliability & Power Quality	4.645	9.375	8.485	8.820	8.640
D - New Customer / New Revenue	4.257	4.257	4.257	4.257	4.257
E - Grid Modernization & Pilot Projects	1.050	3.650	4.400	4.900	4.900
F - Government Requirements	0.950	0.700	0.700	0.700	0.700
G - Metering	5.850	1.950	1.950	1.950	1.950
H - Other	2.680	0.680	0.680	0.880	0.680
Total ($ in Millions)	**$42.354**	**$44.576**	**$44.407**	**$44.957**	**$44.832**

Figure 9: Five Year Future Investments (by category)



Age Related Replacements and Asset Renewal Projects (Category A) are used to replace failing and end of life infrastructure on the distribution system. Some age-related replacements and asset renewal projects are planned in advance and implemented proactively as engineers identify and prioritize age- and condition-based replacements or areas prone to failure based on reliability metrics and feedback from field crews. Other age related replacements and asset renewal projects are implemented in response to unanticipated failures. Engineering expertise helps prioritize proactive age related and asset renewal efforts. In some cases, the Company experiences a number of failures in a certain area of the system or with a particular type of asset and these failures inform where to direct capital spending. However, some age-related replacements naturally occur throughout the year due to unanticipated failures. At the transmission-to-distribution substation level, where failures can be more broadly impactful, costly, and have longer lead times to fix, proactive asset renewal modernization projects have been identified and prioritized based on the age, past performance, and direct customer impact of major substation apparatus.

System Upgrades for Capacity (Category B) or Reliability & Power Quality (Category C) are driven by improvement of load-serving capacity or customer reliability. If voltage or capacity issues are identified because of load growth on a circuit, the

Company may need to reconductor a portion of a circuit to ensure continued reliable service. In the past, the Company has needed to build new distribution substations from time to time in order to increase load-serving capacity. If a certain area experiences exceptionally poor reliability over a short period of time, distribution engineers and planners may evaluate the local system and identify potential reliability improvements. Field crews are invaluable resources for feedback on areas of the system that could benefit from capacity or reliability improvements. With the prevalence of AMI on the system, the Company has been able to more frequently and preemptively identify areas of the system with power quality issues.

In some cases, system upgrades for capacity or reliability and power quality will be integrated with Asset Renewal or Grid Modernization projects to more efficiently and holistically address the needs for the area. Many projects provide benefits in all four areas, and identifying the primary category for such projects is not a precise exercise. A project with a strong reliability component, such as reconductoring a section of feeder to a tie switch to ensure adequate backup capability for planned or unplanned outages, might also increase the capacity of the feeder. Although the main purpose of the project is to reliably serve load from another source during an outage, there is an inherent increase in capacity gained as well. The very same project may also involve the replacement of end-of-life poles and conductor, thus achieving a strong asset renewal benefit at the same time.

New Customer Projects and New Revenue projects (Category D) include construction of distribution line extensions to serve new customer load. The Company has an obligation to serve new load within its service territory. Most new customer projects result in new (increased) revenue. A small number are revenue neutral. Most individual line extensions are less than $2,000. The distance from existing facilities to the new service point is the most common condition that will determine the cost. Line extensions are made in accordance with Company's Electric Service Regulations and commission-approved tariffs. The extension rules specify an allowance (credit) for each rate class. Extension costs that exceed the allowance are paid by the customer or may be covered by a guaranteed annual revenue agreement (excluding single-phase services) if the customer enters into a five year electric service agreement.

Grid Modernization Projects (Category E) are efforts that go beyond the Company's baseline efforts to maintain safe, reliable, and affordable energy but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. These projects are identified and selected through analyzing reliability metrics and determining what solution or suite of solutions is best suited to improve reliability on the system. Most often, this involves the deployment of more intelligence on the distribution system such as line sensors, motor operated switches, automatic switches, fault indicators, and trip savers. The Company is in the process of rolling out a multi-year plan to install smart switches ("IntelliRupters") and the associated communications infrastructure improvements in strategic locations on the distribution system. Increased information from the distribution system helps improve customer communications and reliability of service.

Pilot projects (also included in Category E) are the Company's efforts to work with new and emerging applications on the distribution system. Pilots are most often projects that the Company has little to no experience with and are meant to facilitate learning and ensure that an effort is worth pursuing on a larger scale before expending large amounts of capital. The Company has pursued a number of pilot projects in the past that have resulted in tangible customer benefits, cost savings, and lessons learned. Moving forward, the primary goal of pilot projects is to find more cost savings and customer benefits with new and emerging technology and applications.

At this time, the Company does not have a detailed cost-benefit analysis for any of the projects included in Category E of the 5-year investment plan. Many Grid Modernization projects are either still in the pilot project phase or are just beginning to build on previous pilots like those discussed in Section III.A. Grid Modernization projects are generally intended to achieve both quantifiable benefits, such as reduced customer outage time and reduced need for field deployments and restoration, as well as non-quantifiable benefits, such as improved power quality, enhanced customer experience, and increased operational visibility and control of the distribution system. As discussed in

Section III.C in this 2021 IDP filing, the Company has initiated a consultant-led Distribution Non-Wire Alternatives Study to gain experience with the evaluation, development, and justification of non-wire solutions, which the Company views as a subset of the Grid Modernization category. One of the outcomes of this study will be the development of a cost-benefit framework for determining where non-wire solutions provide sufficient value to recommend moving forward, which could then potentially be used by the Company to evaluate future Grid Modernization projects as they are developed.

The most common projects related to Government Requirements (Category F) are relocation of lines located in public rights-of-way and relocation of distribution lines to avoid road construction conflicts. By the rules of the governing authority having jurisdiction, most projects are not reimbursable to the Company by local governments. Only relocation of existing lines outside road rights-of-way and protected by private property rights may be reimbursable.

Metering Projects (Category G) are related to the procurement, installation, and communications of energy measurement technologies used for financial transactions. The main drivers for metering projects include:

- Supply usage information to customers: Interval usage information is loaded into the MyAccount customer portal available on the Minnesota Power website.
- Increased communications failures, unsupported technology, or limitations of the technology of the legacy AMR system due to end of life and obsolescence of technology. These meters are replaced with AMI meters, decreasing the frequency of billing estimations.
- Integration of AMI and the OMS: Every AMI meter acts as an outage detection sensor and reports power restorations.
- Replacement of the aging dual fuel and controlled access control systems: AMI meters replace legacy socket collars, and are controlled with the AMI system, which allows for future improvements that support reliability with increased variable renewable energy on the system.

Projects included in the “Other” category (Category H) improve Distribution assets operations but do not meet the categories or drivers discussed above. Some examples include replacing assets due to damage incurred to the system by an unidentified third party for which there is no reimbursement or due to storms, but the largest recent project in this category is the Street and Area Light Replacement Project.

1. Outage Management System

The OMS manages the detection, location, isolation, repair and restoration of faults which occur unexpectedly on the distribution system, in addition to managing planned distribution outages. It provides support to operators at all stages of the outage life cycle, starting from events--customer reports, AMI outage notifications, Supervisory Control and Data Acquisition (“SCADA”) operations, and notification from the field crews--and concluding with the restoration of electric service. The OMS is the overall coordinator of all tasks, processes and record keeping associated with the resolution of distribution outages and is the single source for communicating outage information to internal and external stakeholders. Currently, Minnesota Power customers are able to view and report outage information through the Minnesota Power app.

The OMS must utilize information provided from the GIS for an accurate representation of the distribution system. GIS data must go through a complex mapping process before it can be utilized by the OMS. The current GIS technology is not fully compatible with the OMS, leading to lost hours of productivity, which has resulted in the OMS having inaccurate and/or incomplete representation of portions of the distribution system. This in turn has limited the OMS’s ability to accurately predict outages in certain locations and, in some cases, for the OMS to predict outages where none were actually present. In addition, the OMS application and the servers and databases it runs on are all approaching end of support, increasing the potential for security, functionality, and performance issues to emerge for which no solution is available from the manufacturer.

Given these issues, Minnesota Power is in the planning phases of a project to replace the existing OMS with a modern, feature-rich OMS from another vendor. This new OMS is anticipated to be in-service in 2023. The upgraded OMS will improve integration with the GIS to eliminate or greatly reduce the mapping errors described above. This mapping improvement, combined with the Utility Network Model project described in Section I.E.2 - GIS, and AMI deployment, including the ability to detect electrical phase, will result in the OMS having a more accurate representation of the distribution system. This will reduce restoration times by locating isolated outages and improving prioritization of restoration work in multi-outage situations. Customers will be provided more accurate restoration times, potentially increasing customer satisfaction. An upgraded OMS will also position Minnesota Power to more readily implement a DERMS and/or an ADMS to accommodate widespread use of solar and other distributed generation sources if and when the need arises.

Minnesota Power has recently completed contract negotiations with a replacement OMS vendor.

2. Geographic Information System

GIS is the suite of spatial technologies that Minnesota Power uses to store, analyze, and report on its electrical system. The purpose of the GIS at Minnesota Power is to store and analyze spatial information about the features that make up the electrical system and provide internal access to this information, with the potential to expand future external access for customers.

The GIS, as well as the staff that support and operate it, serve external customers in a variety of visible and unseen ways. As described above, data is translated out of the GIS and into the OMS and allows for rapid restoration of power during storms or other outages. Information from the OMS is then sent back to the GIS to support the customer outage map. This outage map was previously maintained by a third-party, but as of April 2019 it was re-designed and re-implemented as an in-house solution that has been seamlessly integrated with Minnesota Power's app where the MyAccount tool can also be accessed.

The current GIS is very stable, but issues have been identified in the shift toward real-time information and mobile technologies. Both internal and external drivers are pushing the GIS to provide more information to more people in more varied locations at increasingly faster speeds. This shift in expectations has amplified issues within the current GIS model both in terms of the information it can store as well as how that information is delivered.

The Company is transitioning to a cutting edge GIS model (Utility Network) that will lower operating costs in a number of areas. The primary benefit of the new system is that it connects data across all of the systems, from generation to customer. As a result, GIS staff will no longer need to spend time transferring data between systems in order to model impacts between the various components of the electrical system. Moving to a more real-time GIS system will lower costs by removing some of the delays in current data integrations. This will allow staff to act on information faster and resolve issues in a timelier manner.

As part of this real-time integration, the GIS is already being used to create work through the use of integrated apps. These apps feed into the asset management system and allow internal users to more quickly generate and complete work in mobile applications.

3. Customer Information System

In 2015, the Company implemented an off-the-shelf CIS to replace a highly customized mainframe-based system that was built in the late 1990s. The CIS is a shared system with Minnesota Power and Superior Water Light & Power and is considered the Company's corporate accounts receivable system, customer billing system and advanced rates engine. The main drivers for the CIS replacement were to replace obsolete technologies for one of the Company's core business systems, increase the efficiency of business operations, target automation and integration opportunities, and further promote data-driven decision making. This system was implemented with the intention of laying the foundation for future initiatives such as the C2M project highlighted below.

4. Customer to Meter Project

Minnesota Power implemented a flexible, highly-scalable upgraded Customer Information solution with advanced meter data management capabilities. The project began in 2018 with the purchase of software. The system implementation period began in 2019 and concluded in 2021, with a system go-live in April 2021. Currently, the system is in the midst of a stabilization period while next phase planning is underway. Initial phase deployment was to build the foundations of the C2M solution. This included an upgrade to the existing customer information application and implementing the modules within the Advanced Meter Billing System. Phase 2 includes the expansion of analytics, additional metering capabilities with other core systems, and exploring further complex and flexible billing functionality. The project objectives are to support key business drivers in regards to Distributed Generation, Grid Modernization, Customer Service, and Meter Asset Management.

The primary aim of C2M is to implement a single software solution to provide the functionality of an Advanced Meter Billing System. This means one database, one framework and application, and one unified user interface. C2M is anticipated to reduce platform costs by an estimated 25 percent and minimize complex integrations between multiple systems. The Company expects many benefits, including cost and efficiency, and functionality within a robust multi-module platform that has streamlined installation and maintenance. This holistic solution involved upgrading the existing CIS system to an Advanced Meter Billing System that includes the following modules: Customer Information Billing and Rates, Meter Data Management, Smart Grid Gateway, Meter Asset Management, and Service Order Management.

The C2M project will improve management of operational devices in the field such as meters and metering equipment. It will make the status of service orders more transparent and allow proactive identification and response to meter alarms and issues.

Benefits for customers include:

- Capability to automate billing for Time of Day and other time-varying rates.
- More comprehensive energy use data in MyAccount.
- Billing estimates will be more accurate.
- Remote service connections and disconnections will be simplified.
- New programs and rates for innovative technology such as electric vehicles will be more readily implemented.

This solution will provide the foundation to respond more quickly to changing regulatory and marketing demands. It will improve the Company's understanding of its customers via data analytics, rate guidance and targeted program offerings to customers, as well as the efficiency and accuracy of the meter asset management process. Additionally it will reduce risk through elimination of the in-house developed system for distributing and analyzing meter data. The total investment in this project will be approximately $9.3 million, which includes $1 million software/hardware licensing and $8.3 million in consulting and internal labor costs.

5. Groundline Inspection Accounting Shift

Minnesota Power is preparing to expand the current groundline inspection program to provide better reliability to the distribution system. With the expanded inspections, poles experiencing deterioration below the surface will be more frequently identified for remediation, potentially giving the perception of an increased failure rate, but in actuality reflecting the more proactive approach. This will require additional response when compared to the existing program. The new program will treat the poles with an Environmental Protection Agency-approved chemical that extends the life of the pole, identify areas to truss the pole to increase the life expectancy, or determine the pole is a candidate for replacement. These expanded inspections will result in additional costs compared to the existing inspection program. The Company can capitalize the majority of these costs because of the life expectancy increase. Importantly, this new program will provide better reliability, resiliency and a longer life expectancy of pole assets.

E. Current Projects

The Company's five-year distribution capital plan includes three projects that are anticipated to have a total cost of greater than two million dollars. Two of the three projects represent asset renewal programs that include individual projects with total cost of greater than two million dollars. The estimated cost and expected benefits of these projects are discussed in Table 4. Since all of these projects are either asset renewal projects whose main driver is age-related replacement of end-of-life equipment or have a strong fundamental asset renewal component to them (in addition to addressing other needs), they are not viable candidates for non-wire alternatives, as explained in Table 4 and discussed in Section III.C.

Table 4: Distribution Projects over $2 million

Project Name	Preliminary Cost Est.	Anticipated ISD	Project Area	Project Description
Switchgear Replacement Program	$2.0M $7.5M	2025 2026	*Anticipated Substations*:* Colbyville, Haines Road (Duluth) **subject to change based on asset renewal project prioritization*	Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Switchgear Replacement Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. Planned age-related replacements include distribution-voltage indoor switchgear, transformers, and associated equipment. The Switchgear Replacement Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of aging substations with indoor switchgear throughout Minnesota Power's system, addressing the unique needs and constructability considerations of these sites. In 2019-2020, the prioritization of Substation Modernization and Switchgear Replacement program projects was re-evaluated and updated to be consistent with the overall transmission and distribution asset renewal needs of each site.
Substation Modernization (Asset Renewal) Program	$7.8M $9.9M $10.7M $5.9M $3.9M	2022 2023 2024 2025 2026	*Anticipated Substations*:* Long Prairie, Silver Bay, Cloquet, Verndale, Little Falls, Winton, Hibbing, Nashwauk, Virginia **subject to change based on asset renewal project prioritization*	Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. Planned age-related replacements include outdoor circuit breakers, transformers, switches, and associated equipment. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In 2019-2020, the prioritization of Substation Modernization and Switchgear Replacement Program projects was re-evaluated and updated to be consistent with the overall transmission and distribution asset renewal needs of each site.
Canosia Road Substation 34 kV Expansion	$2.2M	2022	Cloquet	The Canosia Road Substation 34 kV Expansion will be the first step and foundation in a multi-year plan to modernize and improve the Cloquet-area distribution system. There are several factors driving the need for improvements in the Cloquet area: • *Asset Renewal & Standardization:* Implementing a standard 34.5 kV backbone distribution network for the Duluth/Cloquet area. There are presently three different backbone distribution voltages between Duluth, Cloquet, and Hinckley. The Canosia Road Expansion and subsequent projects will convert existing 24 kV and 46 kV systems to 34.5 kV while addressing asset renewal needs for existing feeders and stepdowns associated with these systems • *System Capacity & Asset Renewal Project Constructability:* Enabling the Cloquet Substation Modernization (Asset Renewal) Project to take place. Cloquet Substation is one of the highest-priority asset renewal sites in the Minnesota Power system, but the distribution system lacks sufficient capability to reliably support the Cloquet area during the extended outage of the Cloquet Substation that would be needed to implement the asset renewal project • *Reliability & Grid Modernization:* Improving reliability for Cloquet-area customers by reducing feeder exposure, providing backup capability from new feeders and 34/14 kV stepdowns, and enabling feeder automation projects to be implemented for enhanced visibility and rapid system restoration

F. Analysis and Visibility of System Data

1. Software

Minnesota Power currently uses industry standard software, Milsoft's WindMil platform, to perform basic distribution analysis routines such as voltage drop, load balancing, fault current analysis, and switching studies for distribution planning. WindMil models are GIS-based, requiring similar labor-intensive translation of GIS data as the OMS. Historical billing load data is used to allocate aggregate feeder load to consumers. As with other systems discussed previously, there are considerable opportunities for improvement and interconnectivity in both spaces (GIS and load allocation) as Minnesota Power continues to make foundational investments and improvements in its GIS system and metering infrastructure. Under the current methodology, the WindMil model-building process is not nearly efficient enough to support a significant expansion in the need for distribution planning studies, for example to support a large volume of DER interconnection studies. As the use and planning of the distribution system continues to evolve, Minnesota Power will evaluate available and emerging software platforms and integration options to ensure that it is implementing optimal analytical tools for its distribution planning efforts.

In late 2018, Minnesota Power became part of the Electric Power Research Institute's ("EPRI") Distribution Resource Integration and Value Estimation ("DRIVE")[16] Tool User Group in order to gain understanding of hosting capacity analysis and the data and labor requirements for performing a comprehensive system-wide hosting capacity study. While Minnesota Power's experience with direct implementation of the EPRI DRIVE tool has been limited to date, significant inroads have been made in working with EPRI to understand how the DRIVE tool interfaces with Minnesota Power's existing WindMil models and how to produce hosting capacity heat maps from these models. Minnesota Power has been able to produce hosting capacity results for a handful of feeders, but further evaluation is necessary to determine the appropriate criteria to include in the production of hosting capacity heat maps. Example preliminary hosting capacity

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[16] The EPRI DRIVE™ software determines the maximum amount of DER each distribution feeder can accommodate in its current state before unacceptable reliability, power quality, protection and thermal issues start to emerge.

heat maps for three of the Company's feeders are provided in Appendix F. One of the goals of participating in the DRIVE User Group is to develop the tools and expertise needed to produce hosting capacity heat maps where appropriate for Minnesota Power's system, but it is important to ensure that the fundamental technical inputs to this process are accurate and appropriate before rolling it out on a more expansive level. It is also important to understand the overall investment of resources that would be necessary to produce and disseminate hosting capacity analysis more broadly for Minnesota Power's system and how the effort would align with other initiatives and priorities discussed throughout this document. At this time, Minnesota Power's approach is to gain experience with the process and methodology to be able to produce hosting capacity analysis for targeted areas of higher interest, as well as continue to engage with the DRIVE User Group to understand additional insights and value streams that could be derived from the EPRI DRIVE tool.

Minnesota Power uses four different methods to monitor and control its distribution system: SCADA, smart sensors, automated/advanced meter data collection, and manual meter reading. Each of these monitoring and control methods is discussed briefly below.

The SCADA system oversees the state and health of the distribution system on roughly half of the Company's feeders. This system brings back measurement data in the form of analog (e.g., Amps, MW, MVar, MVA, and kV) and binary (e.g., statuses, alarms, and outages) values from these feeders. The SCADA system measures analog data in 4 second intervals and binary information in 60 second intervals as well as when there is a change of state. The information is recorded in a historical database that is accessible for engineering planning and analysis. In addition, the SCADA system enables Minnesota Power's system operators to remotely operate breakers and motor operated switches to isolate faulted equipment and feeder sections, greatly expediting the restoration process, enhancing reliability, and reducing customer impacts.

Smart sensors are installed on feeders that do not currently have SCADA installed. These feeders' substations are usually in remote rural areas where communication paths are limited. The smart sensors monitor voltage and current near the feeder breaker and store measured data offsite in a data historian. A secure account is used to review and download the information for engineering and event analysis as well as restoration efforts. Minnesota Power has installed these sensors at most substations that do not have SCADA in order to gather better data and eliminate manual reads.

Manual reads are occasionally collected by operations personnel during substation inspections. These reads collect peak amp data each month and are reset upon reading. This information is then housed in the Company's asset management system for analysis. There are a number of rural 4kV feeders on the distribution system that are not read or inspected because they are remotely located and serve a very small number of customers. Most of these locations are part of the investment plan and will be upgraded or removed in future years.

Minnesota Power has two different automated meter collection systems. The AMR system is Minnesota Power's oldest meter collection system and is being replaced with the AMI system. The AMR system records kilowatt-hour ("kWh") and kilowatt ("kW") information. This information is transmitted back to the collection system every 27 hours using powerline carriers. As referenced earlier, the AMR system is being replaced with AMI, which will ultimately become the standard for metering. While customers will continue to be provided the option to opt out of AMI, this will be using non-standard metering and processes, which may involve a customer opt out charge. The AMI system records voltage, kW, kWh, kilovar-Hour ("kVArH"), click counts and informs the OMS of customer outages. As part of the upgrade of the Company's C2M project and the addition of a Meter Data Management system, all meters were moved to collecting 15 minute interval data. This gives customers more granular data through the MyAccount tool, and positions Minnesota Power for future advanced time-based customer rate offerings.

2. System Visibility – SCADA, Smart Sensors, AMI

SCADA & Smart Sensors

Minnesota Power currently has 360 distribution feeders throughout its service territory. Some of these are three phase feeders while others are single phase. Minnesota Power has visibility into and control of primary and three-phase distribution. The Company currently has no visibility or control on most single phase feeders. Of the Company's 360 distribution feeders, 181 feeders (50 percent) have SCADA at the feeder breaker. In 2017, Minnesota Power began implementing smart sensors on the remaining distribution feeders. Through 2020, 138 distribution feeders (38 percent of total feeders) have smart sensors installed near the feeder source. Nine additional locations on four feeders have smart sensors installed to assist in fault locating. By the end of 2022, Minnesota Power will have finished the rollout of smart sensors on distribution feeders. A few of the 4kV feeders that have very few customers and will be converted to a higher voltage were not a part of the smart sensor program. Minnesota Power will continue installing smart sensors in multiple locations on feeders to assist in fault location, increasing real-time visibility on the distribution system and creating efficiencies.

Faulted Circuit Indicators

Minnesota Power is currently testing control capabilities on the distribution system. With the aid of smart sensors and faulted circuit indicators ("FCIs"), the Company plans to continue installing remotely controlled motor operated switches on the distribution system in order to enhance fault isolation and system restoration capabilities. Motor operated switches enable Minnesota Power's system operators to remotely control feeder switches. Smart sensors and FCIs give indication to the system operators about where the fault is located on the feeder. Combining motor operated switch installations with fault location information on a feeder enables Minnesota Power's system operators to utilize the motor operated switches to rapidly isolate the faulted section of the feeder and restore service to customers on the sections of the feeder without electrical faults. All of this switching can be completed by the system operators in minutes, well before a trouble crew could reach the feeder to begin to identify the cause of the fault. With the faulted section of feeder identified and isolated by the system operators, the trouble crew can then focus its efforts on only the faulted feeder section to identify and fix the cause the fault. The end result is a more rapid and efficient response to feeder-level fault events, which should greatly enhance reliability for the customers served from the feeders where this approach is implemented. FCIs are also being deployed as standalone devices to aid in normal fault location and restoration efforts by crews.

AMI

The AMI system allows for efficient metering access, improved data transmission and granularity, and enhanced situational awareness between Minnesota Power and its customers. The meters act as "smart nodes" at each customer's premises, allowing a number of benefits including: efficient deployment of advanced time-based customer rate offerings; outage notifications; notification of service issues (such as low/high voltage, over current, and tamper warnings); improved load control; more frequent customer usage data; and the ability to more quickly reconnect customers who may have been involuntarily disconnected due to non-payment (where remote capability exists). The expansion of Minnesota Power's AMI capabilities also lays the groundwork for further grid modernization initiatives and improvements to the customer experience.

Table 5: Deployment Plan for AMI Meters

	AMI Meters Installed	Remaining AMR Meters
2016 Actual	11,092	92,084
2017 Actual	11,476	80,608
2018 Actual	13,155	67,453
2019 Actual	10,635	56,818
2020 Actual	35,437	21,381
2021 Plan	10,000	11,381
2022 Plan	10,000	1,381
2023 Plan	1,381	0*

**Likely won't be "0" in 2023 due to potential AMI opt-outs*

As of January 2021, there were 122,706 deployed AMI meters on Minnesota Power's system (roughly 84 percent of deployed meters). With the aid of a Smart Grid Investment Grant, 8,030 meters were deployed, as described in Section III.A.1 – Time-of-Day/Critical Peak Pricing of the Plan. There were 21,397 deployed meters remaining on the older AMR system as of January 2021. Minnesota Power is a utility leader in Minnesota for AMI implementation and has historically deployed AMI throughout its service territory at a rate of approximately 6-8 percent per year. In 2020 and into 2021, the Company was able to increase AMI installations significantly by redirecting the work assignments of the Meter Reader Collector group while a stay on residential and small commercial disconnections was in effect. With the pause in field collections due to COVID-19, the Meter Reader Collectors had the bandwidth to take on this work. As field collections resume, and with the remote/hard to access nature of remaining meters, the Company is expecting AMI installations to return to historical levels going forward. With current budgeting and staffing, the AMI deployment is expected to be complete in 2023.

G. Communications Strategy

Minnesota Power owns and operates a communications transport system that consists of fiber optics, microwave radios, leased services and other technologies. This system provides communications for all areas of Minnesota Power including transmission SCADA, transmission line protection, distribution SCADA, land mobile radio, business IT systems, voice, video and others. The Company uses a variety of communications methods based on the cost and needed reliability of the application. To support the growing need to monitor and control distribution devices, Minnesota Power is expanding the transport system and exploring new cost effective ways to leverage existing systems and infrastructure.

1. Existing Communications Methods

Fault Location, Isolation, and Service Restoration System

Minnesota Power's FLISR system, which includes reclosers and smart switches, is connected via a fiber optic network switch system that is purpose-built and is isolated from all other Minnesota Power communications systems. Extending the isolated fiber optic network switch system is the preferred communications solution for additional smart switch devices. This solution provides fast and reliable communications with strong network security. The Company will continue to evaluate alternative communication options for the FLISR system as it is expanded, but currently plans to extend fiber communications for this purpose.

Other Distribution Devices

Other Distribution devices such as reclosers, switches, regulators, capacitor banks, etc. that can be operated from the EMS are connected by several different methods:

- The fiber optic network switch system that was built for the FLISR system.
    - Devices that can be economically connected to existing FLISR deployments are connected using that system.
- Unlicensed 900 MHz radios, licensed 450 MHz radios or short fiber optic extensions that connect to a Remote Terminal Unit ("RTU").
    - These solutions leverage an existing substation RTU that is located near the distribution device and is already connected to the EMS via the transport communications system. This allows for a low cost communications channel when there is existing infrastructure in the area.

All of these solutions are in the Company's toolbox but require project-specific engineering to determine the most cost effective and economical solution for the Company's overall vision. Minnesota Power continues to evaluate these solutions and new technologies to ensure the best options are provided.

2. Pilots and Future Expansion

Land Mobile Radio Based Communications

Minnesota Power's existing land mobile radio ("LMR") system vendor supports an add-on solution to provide a low speed SCADA connection to any device within the radio coverage area. The LMR system has coverage in a large majority of the service area, making this a potential wide scale and cost effective solution. A proof of concept of the LMR based solution was completed in the lab using a spare recloser in 2020 and the system functioned well. The Company is currently scoping a field pilot of the solution that would connect a few distribution devices in the Duluth area to the EMS. If pursued, this field pilot could be deployed in 2022. Enabling this capability across the entire LMR system requires a system-wide upgrade from the current analog trunked mobile radio to a digital mobile radio ("DMR") system. The upgrade is currently underway and will be a multiyear staged project, with the first fully-updated DMR sites coming online in 2022 and a target completion by 2025.

AMI Based Data Communications

Minnesota Power is working with its current AMI vendor on a pilot of their distribution automation ("DA") communications solution. This system utilizes existing AMI radio infrastructure, allowing the Company to leverage it for DA communications. One challenge with this specific DA solution is cyber security, as the control portion of the solution is cloud-based. There will be more to come with the option as the pilot continues.

Cellular Connected Multiprotocol Label Switching Routers

Minnesota Power in the process of replacing the current communications transport system with a Multiprotocol Label Switching ("MPLS") system. This planned replacement will be a multiyear staged project with the first MPLS sites coming online in 2021 and a target completion by 2027. The new MPLS system supports cellular connected routers that may be an option for some distribution communications needs. This option is two to four years out and will require engineering and cyber security review.

H. Cyber Security

With enhanced data and system capabilities, and increased DERs on the utility system, it is imperative that the Company continues to evolve its cyber security program to ensure the security and integrity of customer and utility systems and data. Minnesota Power has built a multi-layered cyber security program based on the Center for Internet Security's internationally accepted Critical Security Controls for Effective Cyber Defense framework to prevent, limit the impact of, and ultimately recover from impacts caused by cyber threats. In practice, Minnesota Power's cyber security program addresses: Dedicated Cyber Security Program and Leadership, External Sensing, Internal Sensing, Intrusion Prevention, and Intrusion Detection and Mitigation. The program continues to be enhanced and adjusted to protect Minnesota Power's cyber systems from the evolving threat landscape. More information on the Company's cyber security program can be found in the Company's most recent Safety, Reliability, and Service Quality Report.[17] Additionally, Minnesota Power collaborates with neighboring utilities, industry specific groups, industry partners, and public officials to share best practices for both cyber and physical security. Minnesota Power's Cyber Security Team has been nationally recognized by it vendors for its work with Enterprise Detection and Response ("EDR") and Security Orchestration Automation and Response ("SOAR") tools.

[17] Docket No. E015/M-21-230

SECTION III:

Demonstrating Innovation

III. DEMONSTRATING INNOVATION

Minnesota Power has a long history of demonstrating innovation with new technologies and customer programming while being one of the most unique utilities in the country in terms of its customer mix and load profile. As the Company continues its Energy***Forward*** journey to a zero carbon future, this value of innovation will be critical as the grid evolves to accommodate evolving customer expectations and power supply changes. This section will provide an overview of Minnesota Power's current and past pilot projects, the evolution of integrated distribution planning and the analysis of non-wires alternatives.

A. Current and Past Pilots

Minnesota Power has routinely implemented technology solutions, where appropriate, to assist with outage detection, response time to outages, and to respond to customer expectations regarding more timely communication and transparency of operations. At the same time, the Company has piloted innovative technology in order to test the feasibility of certain applications for the distribution system, while utilizing resources wisely to gain benefits. The pilots outlined in this section are examples of how the Company continues to carefully leverage internal and external resources to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid.

1. Time-of-Day/Critical Peak Pricing

Minnesota Power's Smart Grid Investment Grant project ("SGIG") involved the installation of advanced metering infrastructure and explored the application of distribution automation. The project was aimed at improving customer understanding of their electricity usage, reducing operation and maintenance costs, and improving awareness of and response to distribution system outages.

As part of its SGIG, Minnesota Power designed a two-phase Consumer Behavior Study Plan ("CBSP"). The CBSP, branded as the Power of One Choice Pilot, began in the spring of 2012 and was implemented in the Duluth/Hermantown area. Phase One of the research was designed to answer questions about residential customers' interest in, use of, and benefits derived from different levels of resolution of feedback on electricity consumption—monthly, daily, and hourly. Phase Two of the research, which began in October 2014 and ran through October 2015, entailed offering a Time-of-Day ("TOD") Rate Pilot with a Critical Peak Pricing ("CPP") component to a subset of Minnesota Power customers. The installation of AMI allowed the Company to initially offer about 660 volunteer customers another rate option that includes a time aspect that better reflects the cost of providing electricity. As of August 2021, there were 325 customers on this rate.

Table 6: TOD Rate Structure

Current Rate Structure May 2017 - Present	
On-Peak Hours	08:00 - 22:00 Monday - Friday
Off-Peak Hours	All other hours & designated Holidays
Summer CPP Hours	12:00 - 15:00
Winter CPP Hours	17:00 - 20:00
On-Peak Increase	$0.0487
Off-Peak Discount	-$0.0299
CPP Event Increase	$0.77

In February of 2018, the Commission ordered Minnesota Power to engage stakeholders in evaluating alternative rate designs and TOD periods for a system-wide TOD rate. A March 2018 survey revealed that, generally, Minnesota Power's TOD Rate participants believe that the TOD rate gives them more control over their electricity costs. Despite its effectiveness and success, Minnesota Power has seen attrition over time, as evidenced by current enrollment numbers, and believes its current TOD Rate Pilot program has come to its natural conclusion. The rate has remained closed to any new participants. The Company evaluated various alternative rate structures through the stakeholder process as outlined in a separate docket.[18]

On December 1, 2020 the Company filed a petition to change the residential rate design.[19] At the time of submittal, Minnesota Power was the only utility in the state to have

[18] Docket No. E015/M-12-233

[19] Docket No. E015/M-20-850

an inverted block rate ("IBR") structure in place. This filing represented a first-of-its-kind proposal in Minnesota to propose a default TOD rate for all residential customers. The petition supported goals collectively identified in the extensive stakeholder process, including: encouraging beneficial electrification, sending price signals to align customer behavior with system efficiency, providing customers with more control over their energy bills and protecting vulnerable customers currently benefitting from the affordability provisions inherent in an IBR structure. The petition proposed:

- A phased transition away from the IBR structure to an interim flat rate, followed by a default TOD rate for all residential customers
- A phased approach to implement discounts for all low-use customers initially to mitigate the impact of the transition from IBR, followed by a discount for low-use, low-income customers
- A phased approach to allow time for education and outreach so customers are prepared for the changes and have the information available to alter their usage accordingly, and to provide time for outreach to low-income customers to ensure they benefit from the discount in Phase Two

On August 27, 2021, the Commission issued an Order approving Minnesota Power's proposal to begin the transition away from IBR and toward a default TOD rate for residential customers. This significant change in residential rate design, which began implementation of Phase One on October 1, 2021, will set a foundation for efficient use of renewable energy, empower customers with more control over their energy bills, and remove barriers to electrification while maintaining important affordability provisions.

2. SolarSense Low-Income Solar Program

Minnesota Power continued to discover opportunities to overcome the solar adoption challenges commonly faced by low-income customers through the Low-Income Solar ("LI Solar") Pilot Program. These challenges can include lack of upfront capital, home ownership status, physical condition of the home, low credit scores, limited access to information and more. This program was intentionally designed to be flexible to encourage a wide variety of project structures, partnerships and creative solutions to address these barriers. The Company awarded $220,000 towards qualifying low-income solar projects since the program was introduced in 2017 through 2020. On December 17, 2020, Minnesota Power's proposal to convert the Low-Income Solar Pilot Program into a Low-Income Solar Grant Program was approved in Docket No. E015/M-20-607. The new program increased annual grant funding to $120,000 through 2024 and will continue to explore innovative ways to create a viable, long-term solar market for low-income customers. Examples of projects funded through the LI Solar Pilot Program are outlined below:

American Indian Community Housing Organization (*"AICHO") Solar Project*

Minnesota Power funded a 14.4 kW solar PV installation on the roof of the AICHO building in downtown Duluth. The AICHO building serves as a central hub for the Native American community in the region, providing housing services for people suffering from long-term homelessness, transitional housing for survivors of domestic abuse, and a 10-bed domestic violence shelter. They host cultural events, art shows and performances. The energy generated by the solar array will directly serve the shelter as well as indirectly serve the tenants of 29 apartments through powering offices and the auditorium, which provide services to all residents. In addition to reducing the operating costs of the facility, the installation will provide educational opportunities to residents of the building and the general public. Prior to installation of the solar array, an energy audit was performed and energy efficiency upgrades were made to the building.

Rural Renewable Energy Alliance ("RREAL") and Tri-County Community Action Partnership ("TCCAP") Project

RREAL and TCCAP received a grant in 2019 for a 20 kW solar array at TCC's headquarters in Little Falls. A subsequent grant was awarded for an expansion of the solar system that was completed in 2020 bringing the total capacity to 34.4 kW. Energy generated by the solar array will benefit Low Income Home Energy Assistance Program ("LIHEAP") -eligible households in central Minnesota. Preference will be given to disabled veterans for this project. The system is expected to begin dispersing benefits in 2021.

Lincoln Park Solar Project

Minnesota Power provided funding through the LI Solar Pilot Program for a 40 kW project in Duluth's Lincoln Park neighborhood. The project will benefit the Minnesota Assistance Council of Veterans in Duluth and Minnesota Power customers facing utility disconnection. The pole-mounted solar array is prominently located along I-35 in Duluth at the eastern entrance to the Lincoln Park neighborhood. The solar array was commissioned in October of 2020.

Habitat for Humanity

The Company provided funding towards the installation of a solar system on the roof of a home built by Habitat for Humanity. RREAL worked with the Lakes Area Habitat for Humanity to provide hands on training and education about the system to the new homeowners. The solar system will reduce the energy costs for a low income family. This project was completed in 2020.

3. Level 2 Electric Vehicle Supply Equipment Donation Pilot

As part of the Company's ongoing efforts to support and develop EV resources, the Company began an initiative to deploy 20 Level 2 Electric Vehicle Supply Equipment ("EVSE") dual-head chargers across its service territory. This effort was based on a Request for Information and subsequent Request for Proposals undertaken in 2019. After a review of available technology and associated pricing, the Company further explored partnering with host sites and/or owning public, workplace, and multi-unit dwelling charging infrastructure to increase availability of Level 2 chargers.

The Company began deployment of the EVSE assets with partner site hosts in the fourth quarter of 2019 and is currently collaborating with approximately 21 different commercial site hosts/partners as some site hosts requested to split the dual charge heads and resolved to host only one head/plug. To date, 14 locations have been identified and are under development, nearing completion, or are operational. Seven sites are still in negotiations or early stage development. The onset of the COVID-19 pandemic and the corresponding community response has affected development activity and the ability of partner site hosts to engage in this effort, but the Company is expecting to complete the installations in 2021.

4. Street Lighting – LED Replacement Project

In the 2019 Rate Case, Minnesota Power proposed elimination of the Option II and Option III rates for lighting, which have been closed to new installations since 2008 and 2009 respectively. Because of the Rate Case settlement in 2020, the elimination of Option II and III will be requested during the next Rate Case filing. Minnesota Power also proposed elimination of all mercury vapor fixtures to be replaced with energy efficient LED ("light emitting diode") fixtures by the end of 2020. This option has been expanded to include all light fixture replacements to LED fixtures. The project scope was so large for the expansion that Minnesota Power labor resources would need at least three years to complete this project. In 2020, Minnesota Power replaced over 7,500 lights with energy efficient LED lights. In 2021, approximately 5,000 more lights will be replaced with LED lights. In 2022 and 2023, the remaining number of lights company-wide will be replaced. This will eliminate all old, outdated fixtures and allow for simpler application of the rates, as only Option I and Option IV are likely to remain, assuming approval to eliminate II and III.

This conversion to LED provides many benefits to customers. The LED fixture upgrades will have no replacement cost to customers. Most customers will no longer have to maintain their own lights, Minnesota Power will be responsible for maintenance of all lights under Option I. Also, customers will experience fewer outages of lights, due to the longer operating life of LED fixtures. Customers may see reduced lighting rates or energy usage with the more efficient LED fixtures. On August 23, 2021 the Company received an Order in Docket No. E015/M-20-830 approving upgrading all Flood and Large Area Lights to complete all older style fixture replacements to LED technology.

5. Street Lighting – Option III

In 2009, Minnesota Power closed Option III lighting to new installations. Option III lighting is a customer installed, owned and maintained light fixture that is not metered. Customer equipment is connected to Minnesota Power's electric system with a disconnect switch provided by the customer. Minnesota Power bills the customer per fixture for each of the fixtures connected. In the upcoming rate case Minnesota Power will propose elimination of the Option III rate entirely, requiring Option III fixtures to move to Option IV and requiring Minnesota Power to meter each installation. Minnesota Power plans to replace the existing photo eye in each fixture with an innovative new technology metered photo eye module which can measure the energy usage without installation of more wiring to the electric system and no installation of a meter socket and meter. Other added benefits of this module include:

- Can monitor outage alarms for bad fixtures or bulbs or even a failure of power delivery to the fixture which the Company could report to the customer
- Has sunrise/set tables and is not fully reliant on the photo eye to turn the LED lamp on and off
- Has the ability to group lights together which can be flashed as a safety control
    - Presents possible future integrations with public safety officials to control illumination levels or other features when needed
- Can be told not to turn on if a customer stops paying and saves truck rolls for physical disconnections
- Has the ability to control LED light output which may open up new rates in the future
- Has a built-in global positioning system so the Company knows exactly where they are
- The modules are compatible with existing AMI infrastructure, allowing the company to further leverage past infrastructure investments. Saves the customer and Company money over the installation of a traditional meter socket.

This pilot could result in an overall benefit to customers since dealing with the legacy lights would involve Minnesota Power paying for costly infrastructure changes to install sockets at each location to meter the lights with a traditional meter.

This would also be a viable option for customers installing new Option IV street lights. If there is a whole string of lights together, then a meter socket would make sense, but if it was just a single light or they are spread very far apart, then metering through the photo eye would be more cost effective for both the customer and Minnesota Power. The lighting module is similar in price to a meter and the photo eye is already a required piece of hardware to have for the installation.

6. Volt-VAR Optimization

In March of 2021, Minnesota Power installed its first VVO system by implementing a Dynamic Volt-Amperes Reactive ("D-VAR") system (distribution-level Static Synchronous Compensator or "STATCOM") on a feeder in the Two Harbors area. Prior to installation of the D-VAR, two feeders in the Two Harbors area were served from two separate substations in order to maintain electrical separation between a demanding industrial customer load normally served from one feeder and residential and commercial customers normally served from the other feeder. In the past, tying these two feeders together, for example during a transformer outage or for maintenance of one of the feeders, resulted in significant power quality issues experienced by the commercial and residential customers. The D-VAR system was installed on the industrial customer's tap in order to curb the power quality impacts of industrial processes, such as a motor starting, on the other customers when tying the two feeders together. In this way, the D-VAR project greatly improves redundancy and operational flexibility for the Two Harbors area, allowing for Minnesota Power to take outages without negative impacts to customers and eventually address age and condition related concerns with one of the existing substations, which is 70 years old. D-VARs can be used in a wide range of applications and through this pilot Minnesota Power hopes to gain enough familiarity with the technology to potentially deploy more devices in the future. Future use cases could be anything from additional power quality-related issues, to a conservation voltage reduction application, to solar impact mitigation.

7. Strategic Undergrounding

Strategic undergrounding was first rolled out in 2020 and will continue on some of the Company's worst performing overhead lines. The Company is targeting areas where customers do not allow access to vegetation management, such as tree trimming, and areas where overhead lines are installed cross-country in inaccessible areas with heavy vegetation. The main drivers for strategic undergrounding are reliability improvement, storm resiliency, aging asset replacement, potential Operations and Maintenance ("O&M") vegetation reduction costs, reductions in trouble costs as reliability improves, and more pleasing aesthetics. Locations are prioritized based on feeder reliability, vegetation costs, accessibility for maintenance, and geology. The Company anticipates benefits could include fewer outages, cost savings, enhanced safety, and enhanced reliability.

8. Solar Energy Projects

Grand Rapids Public Utilities

Minnesota Power partnered with Grand Rapids Public Utilities ("GRPU"), one of the Company's wholesale municipal customers, to bring a new Solar plus Energy Storage system to Grand Rapids, MN. The project includes a new 2 MW Solar PV array and a 1 MW/2.5 hour Li-Ion Energy Storage System. The project is located on a property near the Grand Rapids airport and features a pollinator garden. The PV array adds additional renewable energy to the GRPU portfolio, and both the solar and battery systems are being utilized to reduce monthly peak demand. Minnesota Power worked with GRPU to develop tools that forecast GRPU system demand and solar generation on a sub-hourly basis to then determine the optimal dispatch (charging and discharging) strategy for the energy storage system with the goal of monthly peak demand reduction. This case study of battery system optimization will be helpful to Minnesota Power as the company investigates other opportunities for energy storage devices on its own distribution system.

Laskin Solar

As part of the Company's Economic Recovery filing[20] the Commission approved the construction of three new solar projects in Minnesota Power's service territory: Laskin Solar, Sylvan Solar and the Jean Duluth Solar Project. A brief overview of each project follows. The Laskin solar array, located at the Laskin Energy Park in Hoyt Lakes, represents a continued investment in host communities that have experienced impacts

[20] Docket No. E,G999/CI-20-492 and Docket No. E015/M-20-828; Laskin, Sylvan, and Duluth solar make up this suite.

from the Company's closure of coal plants, as coal operations ceased at Laskin Energy Center in 2015 and the facility transitioned to natural gas. The refueling and change in mission to a peaking capacity resource resulted in a significant reduction in the number of employees at the facility along with decreased economic activity in the community. Siting a new solar project at Laskin Energy Center is an intentional effort on behalf of the Company to reinvest in communities impacted by its transition to a cleaner energy future.

Sylvan Solar

The second economic recovery solar project will be sited near Minnesota Power's Sylvan Hydro Station west of Brainerd, Minnesota. The Company selected this site in an effort to spur economic recovery efforts within its service territory, because the land is already owned by the Company, and the location provides proximity to existing Company infrastructure, minimizing the expense and complexity of connecting into the local distribution system. Investment at the Sylvan site reinforces the Company's commitment to economic development in the western part of its service territory.

Jean Duluth Solar Project

The final project in the suite of economic recovery solar projects approved in 2021 is the Jean Duluth Solar project to be sited in Duluth, Minnesota – home of Minnesota Power's corporate headquarters and the Company's largest service center. Jean Duluth Solar would be located in northeast Duluth, on approximately 9 acres of land owned by the City of Duluth. The Company selected this location because it is no longer used for City maintenance activities, it is located close to the Company's existing distribution infrastructure, will provide economic investment in the community that hosts the Company's corporate headquarters and aligns with the City of Duluth's sustainability goals. The City of Duluth has committed to reducing its greenhouse gas emissions 80 percent by 2050, intending to accomplish that goal through a combination of energy conservation, renewable energy projects, supporting multi-modal transportation and adapting infrastructure to the changing climate.[21] As such, the City is supportive of the Company siting new solar projects in Duluth.

9. Reconnect Pilot Program

Minnesota Power's Reconnect Pilot was approved by the Commission on December 9, 2020 under Docket No. E015/M-19-766. This is a voluntary three-year pilot program, under which residential electricity customers whose service has been disconnected due to non-payment would have the option to have their service reconnected remotely after meeting reconnection requirements. A participating customer with a remote-capable meter could have service reconnected within minutes after calling customer service, eliminating the need for Minnesota Power to send staff to the customer's location to reconnect service in person and allowing for a waived reconnection fee for the customer.

Due to the COVID-19 pandemic and the related suspension of disconnections for residential customers facing financial hardship as a result of the coronavirus pandemic, the implementation of this Pilot was postponed. In its August 13, 2020 Order under Docket No. E,G999/CI-20-375, the Commission ordered suspension of disconnections for residential customers; suspension of negative reporting to credit agencies for residential customers; and waiving reconnection, service deposits, late fees, interest, and penalties for residential customers. In its May 26, 2021 Order in Docket No. E,G999/CI-20-375, the Commission adopted a modified Consumer Advocates' Transition Plan, and allowed for the resumption of disconnections on August 2, 2021. With the resumption of disconnections, Minnesota Power is in the process of deploying remote-capable meters, timed with reconnection of service to realize operational efficiency and maximize the potential savings to customers in terms of Company costs as well as direct costs such as future reconnection fees.

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21 https://duluthmn.gov/sustain/goalsmetrics/#:~:text=The%20City%20of%20Duluth%20works,emissions%20by%2080%25%20by%202050

B. Integrated Distribution Planning

Minnesota Power's Transmission & Distribution Planning and Resource Planning departments work in close collaboration with one another. Coordinated discussions take place at regular intervals throughout the year to share information on potential supply side and demand side opportunities located at the distribution level. Distribution Planning and Engineering also provide information needed for inclusion in the distribution appendix to the IRP, and the groups coordinate in the development of the Distributed Energy Resource Scenario Analysis for the Integrated Distribution Plan. As Minnesota Power's Distribution Planning processes evolve, the primary areas of active coordination in the near-term between Distribution Planning and Resource Planning will be load forecasting and vetting of supply-side or demand-side non-wire alternatives.

With respect to load forecasting, Distribution Planning obtains historical loading information by feeder from SCADA and meter data for its entire system on an annual basis. Where necessary to support out-year distribution planning analysis of a particular area, this historical load data may then be provided to Load Forecasting. Load Forecasting develops projected annual growth rates by feeder based on the latest Annual Forecast Report[22] ("AFR") and supplies the growth rates to Distribution Planning to be used to develop an out-year peak load scenario for distribution planning analysis. This ensures that any issues identified in the evaluation of the out-year peak scenario are consistent with the latest load growth forecast from Resource Planning.

For the Distributed Energy Resource Scenario Analysis Section IV.C, the Load Forecasting group provided the base-case scenario for DER deployment on the distribution system. The assumptions for DER deployment in the base-case were aligned with assumptions used in the latest AFR. Load Forecasting, Distribution Engineering, and Distribution Planning then worked together to develop the DER outlook for the medium and high scenarios. Please refer to the Section IV.C– Distributed Resource Scenario Analysis for more details on the approach and results.

[22] Docket No. E-999/PR-21-11

With respect to supply-side or demand-side non-wire alternatives, Distribution Planning identifies candidate reliability or load-serving issues on the distribution system through regular planning assessments. (See Section III.C- Non-Wires (Non-Traditional) Solution for a discussion of how Minnesota Power determines if an issue is a good candidate for a potential non-wires solution.) If it is expected that the traditional solution to an issue will be a major project (greater than $2 million, as established in the IDP Requirements), a subsequent alternatives analysis will be conducted. Within this alternatives analysis, both traditional and non-wires solutions will be considered. For non-wires solutions, scoping-level information about the non-wires solutions (necessary size, location, and operational characteristics required to resolve the issue) may be developed by Distribution Planning and shared with Resource Planning in order to facilitate the identification of viable non-wires alternatives. This includes developing an anticipated cost, implementation timeline, power supply benefits, societal benefits and other potential benefits specific to locating non-wires alternatives on the distribution system. Non-wires solutions considered for the purpose of resolving distribution reliability and load-serving issues will include supply side solutions (i.e. solar and batteries) or demand side solutions (residential/commercial demand response programs).

If any non-wires alternatives identified through this exercise show potential benefits for customers and the distribution system, these alternatives could be considered as resource options in the next IRP. However, the consideration in the IRP of non-wires alternatives for distribution system issues may be impacted by the required implementation timeline associated with the particular issues being addressed. In some cases, a solution may need to be implemented for the distribution system outside of the IRP process.

C. Non-Wires Solutions

Generally speaking, the types of projects that lend themselves to non-wires solutions[23] are those designed to address reliability performance or load-serving issues. Specifically, non-wires solutions may be suitable for addressing reliability performance

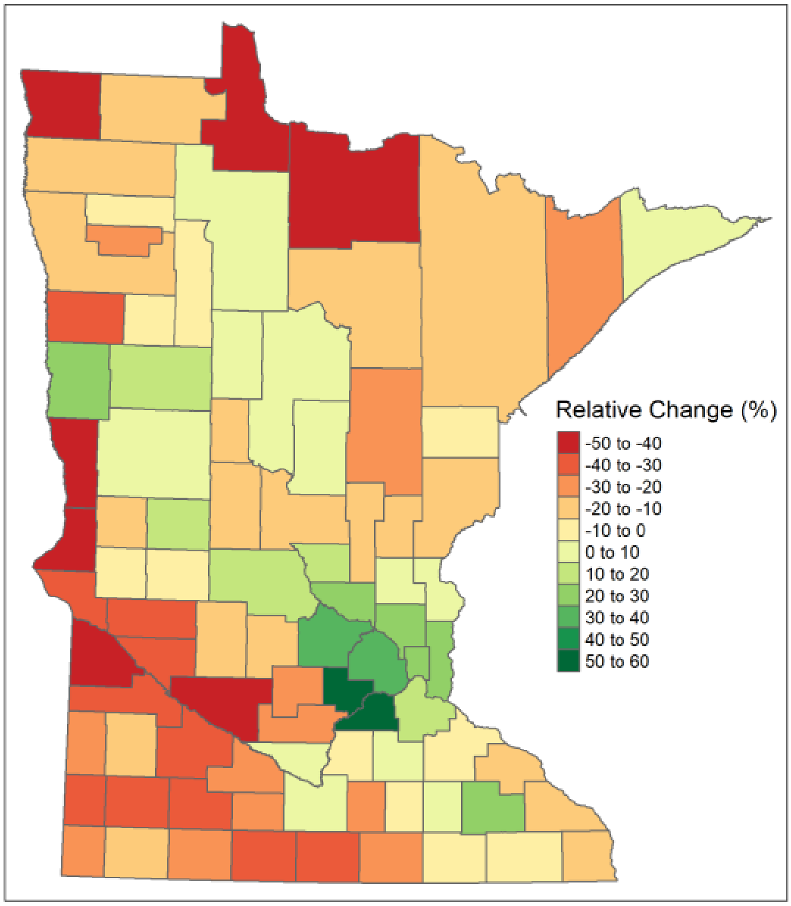
[23] For purposes of the discussion in this subsection of the 2021 IDP, non-wires solutions do not encompass demand response or energy efficiency initiatives. Those programs are addressed in other sections of this Plan.

issues where there is limited or no backup capability following loss of the primary source to a feeder. In that case, a non-wires solution may be able to provide redundancy to the feeder, enhancing restoration times and ultimately improving reliability. A non-wires solution may be suitable for addressing a load-serving issue where the capacity of a feeder or associated substation equipment, including transformers, is less than the total peak load interconnected to the feeder or substation. In that case, a non-wires solution may be able to reduce the effective peak load seen by the feeder or substation to within the capacity of the existing assets, eliminating or deferring the need for infrastructure upgrades. However, non-wires solutions are only viable for these types of issues where the following conditions are also met:

- There is not a significant asset renewal need being addressed. Non-wires solutions cannot displace the need to modernize and replace aging equipment, even when the modernization project may result in increased reliability or load-serving capability. For example, if the issue is transformer capacity at a substation where the transformer is near or beyond end of life, a non-wires solution will not defer the need to replace the transformer for a significant enough period of time to be a cost-effective alternative. There are substations on the Minnesota Power system where transmission-to-distribution transformers as old as 70-90 years are still in use. These substations should and are being addressed through Minnesota Power's Substation Modernization (Asset Renewal) Program.
- The operational characteristics of the non-wires solution adequately correspond to the need. Non-wires solutions, including both supply-side and demand-side alternatives, must be available at the necessary time, with the necessary response, and for the necessary duration to address a particular reliability or load-serving issue. For example, if the reliability issue to be resolved is loss of a feeder without adequate backup capability from another distribution feeder, a non-wires solution must be available for dispatch or demand response, able to ramp up quickly, capable of following load, and sufficient for an appropriate duration based on the restoration time of the feeder.

Additionally, population growth is an important consideration when discussing non-wires alternatives. Minnesota Power's service territory is projected to continue a decline in population through 2053, as shown in Figure 10.[24]

Figure 10: Relative Population Change by County, 2018-2053 in Minnesota



Smart Electric Power Alliance ("SEPA") and Peak Load Management Alliance's ("PLMA") November 2018 "Non-Wires Alternatives Case Studies from Leading U.S. Projects" report listed the majority of case studies as siting forecasts of high load growth as contributors to the identification of the need for infrastructure upgrades and non-wires solutions. Stagnant to declining population growth in a utility's service territory presents a unique challenge when evaluating non-wires options for distribution solutions.

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[24]Minnesota State Demographic Center. (October 2020). Long-Term Population Projections for Minnesota: https://mn.gov/admin/assets/Long-Term-Population-Projections-for-Minnesota-dec2020_tcm36-457300.pdf

The amount of time necessary to identify, evaluate, justify, and implement a non-wires solution will vary depending on the scope and scale of the solution. The components of implementation timeline include:

- Internal analysis, including distribution planning assessments, targeted alternatives analysis for non-wires solutions, and integrated resource planning analysis;
- Project development, including scoping and preliminary engineering for the non-wires solution;
- Project execution, including procurement, permitting, engineering and construction.

Minnesota Power does not currently have sufficient experience with the process of identifying, evaluating and implementing non-wires solutions to provide a specific timeline for this process. In mid-2021, Minnesota Power initiated a consultant-led Distribution Non-Wire Alternatives Study to gain experience with the evaluation, development, and justification of non-wire solutions. The study is focused on specific opportunities on Minnesota Power's system where enhanced backup capability, feeder automation, or dynamic voltage control are or could become desirable. The consultant is tasked with developing a non-wire solution for each opportunity, assisting Minnesota Power in developing a framework for determining where non-wire solutions provide sufficient value to recommend moving forward, and producing sufficient technical scoping information for Minnesota Power to separately develop and procure any or all of the non-wire solutions developed for the study. This study effort is expected to take the entirety of the rest of 2021, and possibly into 2022, meaning earliest implementation for any resulting non-wire solution projects would most likely be in 2023. Minnesota Power can provide an update on the current status of the Non-Wire Alternatives Study during the comment period for this docket.

SECTION IV:

Planning for a Resilient Future

IV. PLANNING FOR A RESILIENT FUTURE

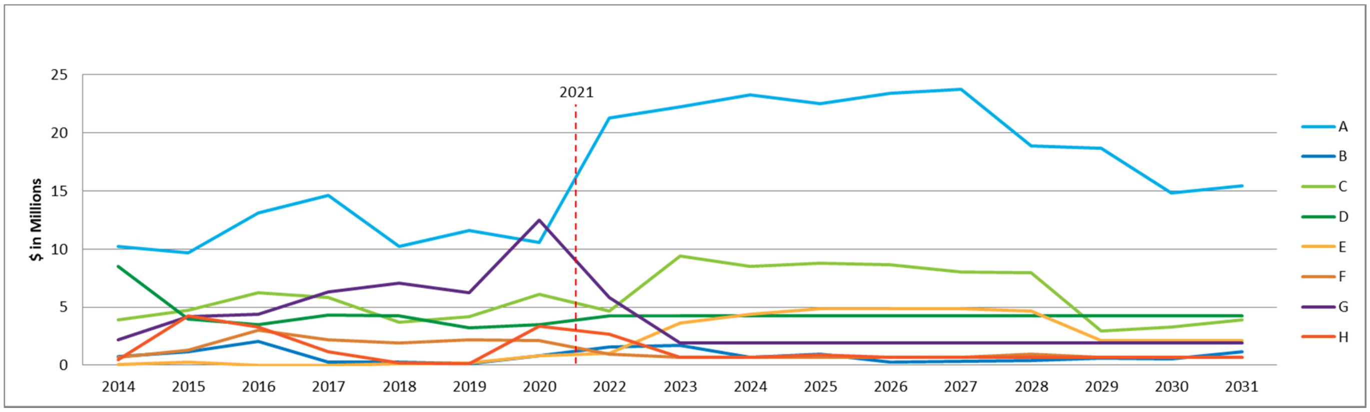
As the industry undergoes dramatic changes, technology advances, customer expectations change and climate change produces increased extreme weather events, utilities will have to plan not only for system reliability but to also ensure a more resilient future. This section of Minnesota Power's 2021 IDP will cover financial planning, potential pilots within the next decade, distribution forecasting, historical loading and preliminary hosting capacity data, and DER system impacts and benefits.

A. Financial Planning

The Distribution long-range plan is reviewed comprehensively on an annual basis. The Distribution Engineering and Distribution Planning departments coordinate the development of the plan, including projects affecting transmission-to-distribution substations as well as distribution feeders and distribution stepdown substations. The long-range plan incorporates localized distribution system reliability and asset renewal needs as identified by Distribution Engineering as well as larger-scale projects coordinated by Distribution Planning where transmission-to-distribution substation reliability, capacity, or asset renewal projects are necessary. Other projects and programs for asset renewal, grid modernization and pilot projects, required relocations, metering, and new customer interconnections are also included in the long-range plan, as identified by Distribution Engineering and Distribution Planning.

The long-range plan generally utilizes historical spending to establish amounts for routine maintenance. Specific projects are slotted into the plan based on timing and need, as identified through asset renewal prioritization, system analysis or external constraints. Many of these specific projects require close coordination with customers, local government, or other business groups within the Company. Since many projects are dependent on timelines and needs outside of the Company's control, a fair amount of changes occur naturally in the long range plan as the Company learns more information. That being said, the Company plans to dramatically increase its capital budget for grid modernization initiatives from 2023 through 2028.

Figure 11: Historical vs Future Spending



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

B. Potential Pilots and Ten-Year Plan

As communicated in Section IV.A – Financial Planning, the Company plans to dramatically increase its investment in grid modernization pilots starting in 2023. Below the Company highlights some areas of interest in regards to potential pilots.

1. Residential and Commercial Customer Demand Response

Minnesota Power has taken proactive steps to expand and modernize its demand response programs outside of the current Dual Fuel and Large Power programs. Within the long-term plan is an investigation of direct control of air conditioning, hot water heaters, electric vehicles, and other loads that could be uniquely controlled through the existing AMI infrastructure and customer outreach. The Company sees numerous advantages in pursuing these DR programs, including gaining key insights from customers on the role that DR can play for them and the enhanced ability to decarbonize additional modes of energy use in alignment with State policy goals.

Minnesota Power has engaged with customers over the last several years to consider how DR programs should be structured to work efficiently for both participating customers and the system as a whole. Key feedback received from those engagements include:

- From a state/national perspective, Minnesota Power's ongoing investments in AMI make implementing new DR programs much easier and more cost effective than it is for other utilities with less AMI penetration
- Commercial customers appreciate the knowledge and relationships that they've gained through working with Minnesota Power's program and services team, and would like a similar relationship-based approach taken with DR programming
- DR programs have to be flexible and provide both environmental and financial benefits for customers
- Customers have varying considerations, from capital available for upfront investment and payback expectations to general knowledge about DR programs and implementation
- More awareness/education/marketing could be done around Minnesota Power's current DR offerings

Minnesota Power will incorporate the learnings and stakeholder feedback as it moves forward in modernizing the commercial customer DR program in the 2021 rate case that the Company plans to file on November 1, 2021.

2. Renewable Load Optimization Programs

One of the known challenges of grid transformation is to identify and access the flexible customer loads to optimize the integration of variable renewable energy production. In addition to demand response, Minnesota Power sees the long-term need for customer facing programs to help optimize the use of renewable energy. While Minnesota Power's system is one of the most unique in the country, with large industrial customers creating a system with a uniquely high load factor, the Company is still committed to attempting to match generation to the load from residential and commercial customers on the distribution system. An example of this may be using peak renewable generation that is exceeding load for EV charging (i.e., work place charging programs). The Company will continue to evaluate the need and applicability of these types of programs as renewable generation increases. Another example is the Company's plans, recently approved by the Commission, to begin transitioning residential rate design from the current IBR structure to a future TOD rate to align customer behavior with optimal use of generation to create system efficiencies.

3. Selective Customer Sub-metering Applications

The Company is positioning itself to leverage measurement infrastructure beyond the utility metering point through investments in meter data management software, and increased energy data collection. These applications will enable informed program design and rate structures for specific electric end uses. This is becoming particularly valuable with the emergence of electric vehicles and charging infrastructure, as well as in the commercial building space. As part of the long-term evolution of data systems and customer programs, it is evident that piloting applications using trusted sub-metering applications may be a critical part of future program designs.

4. Solar/Storage Applications

Minnesota Power has been working diligently with all distribution customer classes in the implementation of solar arrays and battery storage. This resource combination has the capability to provide many reliability and power benefits to customers through future program and system enhancements. The Company plans to investigate and engage customer groups with opportunities to deploy this technology as it becomes more economical for customers. As an example and described previously in Section III, Minnesota Power is currently working with a wholesale customer, GRPU, on a solar project with a battery storage component.

5. Conservation Voltage Reduction

Minnesota Power is considering implementing a conservation voltage reduction (“CVR”)/volt-VAR optimization pilot in future years. CVR is the intentional operation of the distribution system in such a way that lowers the voltage profile along a feeder in order to reduce demand and delivered energy. The system voltage would still remain in the acceptable American National Standards Institute (“ANSI”) voltage range.

In order to implement a CVR/VVO pilot the Company would need to install additional voltage control and reactive power management equipment, such as regulators, tap changers, capacitor banks, or distribution-connected STATCOMs (“D-

VARs"), which would result in additional capital spend and long-term operation and maintenance costs. These costs could be offset by reducing demand and energy on the feeder.

Leveraging the AMI system is critical for a successful CVR/VVO pilot, as the Company can use customer voltage data to confidently push the voltage as low as possible while still maintaining acceptable service voltage within the range defined by the ANSI. Additionally, the AMI system and the future MDM will allow for greater data analysis which would aid in estimating the CVR potential benefits in terms of energy savings and demand reduction.

The Company will be evaluating a cost-benefit analysis framework in the Distribution Non-Wire Alternatives Study (discussed in Section III.C) that may help assess the benefits and potential payback period of a future CVR project. The installation and net-present value costs can be variable depending on which communication protocol is used to operate the devices, which head-end system is used to automate the system, and whether or not existing equipment in the substation and on the feeders can be retrofitted to participate in a CVR pilot. The costs and benefits of VVO also vary by the type of circuit (residential, commercial or industrial load) that the system is installed on.

Minnesota Power plans on pursuing a CVR project in the next couple of years. The pilot location will most likely be in the Duluth area. The pilot project will be used to assess the benefits of CVR while carefully monitoring the end use impacts. Previously, this type of a pilot would have been hard to implement but, with AMI deployment and development of the back end data processing, this pilot is more feasible. One potential Duluth-area application for CVR is included for evaluation in the Distribution Non-Wire Alternatives Study (discussed in Section III.C).

6. Battery Energy Storage System ("BESS")

Currently, Minnesota Power has no sizeable energy storage installations on its own distribution system. There are a handful of locations where a grid-scale battery may prove useful and a small pilot may be pursued in the next five years. In order to scope the pilot project as well as iron out the costs and benefits of an energy storage application, a consultant may be utilized to assist. Minnesota Power plans on primarily targeting areas where batteries can be used as a reliability backup for initial pilots. Potential applications for reliability-based battery energy storage systems are included for evaluation in the Distribution Non-Wire Alternatives Study (discussed in Section III.C).

7. Microgrids

There has been an increased national interest in utilizing microgrids in the recent years, often because of reliability events that have adversely impacted customers. Currently, Minnesota Power does not have any microgrids on the system for a number of reasons. Historically, customers with sensitive or critical loads have installed their own backup generating systems. They might have a redundant secondary supply from the utility. But as reliability and reducing customer outage minutes becomes more and more important, some utilities are piloting microgrids as a way to keep customers in power even when major events occur that impact the distribution system. While Minnesota Power has no specific plans to pilot a microgrid at the moment, the Company is continually evaluating them as a potential reliability solution for customers and anticipates they will become a more viable solution as DER penetration increases and as the costs of new distribution-connected technology comes down. Potential applications for reliability-based battery energy storage systems that could constitute microgrids are included for evaluation in the Distribution Non-Wire Alternatives Study (discussed in Section III.C).

C. Distribution Forecasting

Existing DER capacity located on Minnesota Power's system is taken into consideration in both the state planning processes, such as IRPs, and the MISO's resource adequacy module[25] (Module E-1). Minnesota Power accounts for existing DERs at the system level via two methods, depending on the type of DER:

- The DER is accounted for in the load forecast by reducing customer demand based on historical DER usage or product (such as distributed solar generation), or
- The DER is accredited as a capacity resource and used to meet the Planning Reserve Margin Requirement in MISO Module E-1/IRP. To avoid double counting of capacity, DER resources receiving an accredited capacity value are not taken into consideration in the customer demand outlook by reducing demand (such as customer owned generation at a paper mill).

The method used to incorporate a specific DER into planning considerations is consistent between the IRP and MISO Module E-1, and the above listed methods should be sufficient to capture DER impacts in resource planning and forecasting functions going forward. For its 2021 IRP, the Company developed three scenarios for technology adoption (EV and DG Solar) on the Minnesota Power system. The 2021 Distribution Plan leveraged these same scenarios, updated, and modified them slightly to include assumptions for Time of Day rate adoption and potential installation of 16 new Direct Current Fast Chargers:

1. Base Case – is consistent with the Company's 2021 IRP and 2021 Annual Forecast Report[26] assumptions for EV ownership and distributed solar generation. Additionally, the scenario assumes a transition of residential billing to a TOD rate consistent with the Company's December 1, 2020 Residential Rate Design proposal[27] where TOD becomes the default residential rate by 2027.

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[25] https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc
[26] Docket No.E-999/PR-21-11
[27] Docket No. E015/M-20-850

2. Medium DER – assumes slightly accelerated adoption of EVs and distributed solar generation, a transition to 100 percent residential TOD participation by 2026 (a year earlier than Base Case), and the installation of 16 new DCFC for EVs on the Minnesota Power system beginning in 2023.

3. High DER – assumes an aggressively accelerated adoption of EVs and distributed solar generation, a transition to 100 percent residential TOD participation by 2025 (two years earlier than Base Case), and the installation of 16 new DCFC for EVs on the Minnesota Power system beginning in 2023.

Each DER component (EV, DG Solar, TOD, and DCFC stations) is detailed below. The resulting outlook for a DER component under each of the above mentioned scenarios are described along with the method for forecasting each component.

1. Distributed Solar Generation

Minnesota Power's 2021 Annual Forecast Report includes assumptions for residential and commercial/industrial adoption of distributed solar generation. The 2021 AFR's forecast methodology for distributed solar adoption and resulting decrease in Minnesota Power sales are described below.

New DG Solar installations were projected[28] using the exponential growth observed over the last decade (2010-2020) where the number of new residential solar installations has grown by about 25 percent per year and new commercial installations has expanded by about 6 percent per year. This outlook for the number of new installs is combined with assumptions for the sizing (kW capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for new installs (i.e. installations expected to come online in

[28] Details of the methodology can be found in the Company's 2021 AFR (Docket No. E-999/PR-21-11), Section B iii Treatment of DSM, CIP, DG, and EV in the Forecast

the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company's Base Case forecast assumes about 1,370 new small-scale DG Solar installations, adding almost 15,000 KW of nameplate capacity, will be connected to the Minnesota Power grid by 2030 (i.e. installed in years 2021-2030). This would represent an almost 330 percent expansion over current small scale solar installations' capacity. These 1,370 new installations would generate about 16,000 megawatt hours ("MWh") per year and reduce sales to residential and commercial sectors by an equivalent amount.

The Base Case forecast assumes cumulative capacity expands at a 15.7 percent compound annual growth rate ("CAGR") from 2020 to 2030.

The Medium scenario applies a 2.5 percent adder to the annual growth rates and results in an overall cumulative small scale solar capacity CAGR of about 18.2 percent from present installed capacity to projected 2030 capacity. The high scenario applies a 5 percent adder, resulting in a 2020-to-2030 CAGR of about 20.7 percent.

The outlooks for new DG Solar installations are shown on the next page in Figure 12 and Figure 13. Figure 12 shows the projected reduction in annual sales due to new distributed solar, and Figure 13 shows the predicted reduction in Minnesota Power's summer peak resulting from coincident solar generation.

Figure 12: Distributed Solar Generation (MWh)

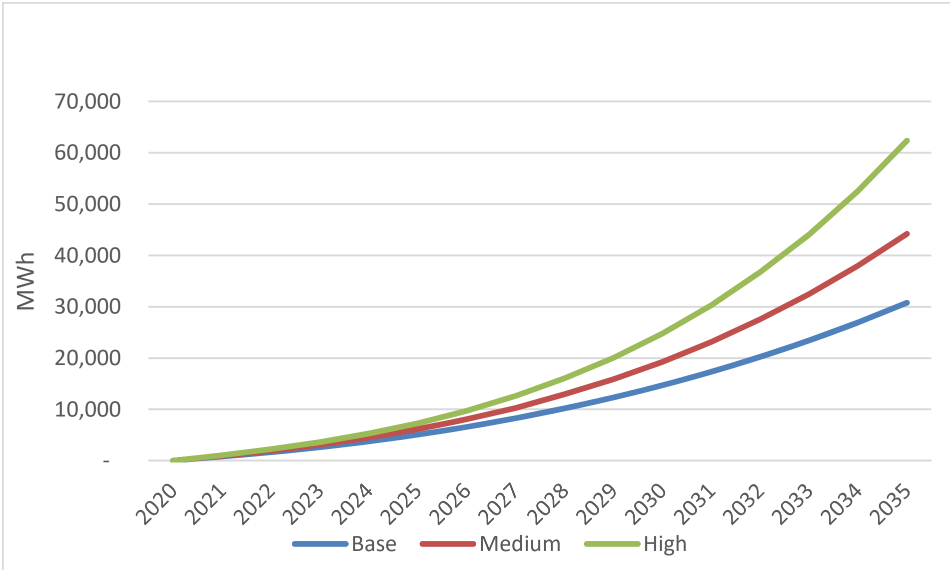

Figure 13: Distributed Solar Generation (Summer Peak)

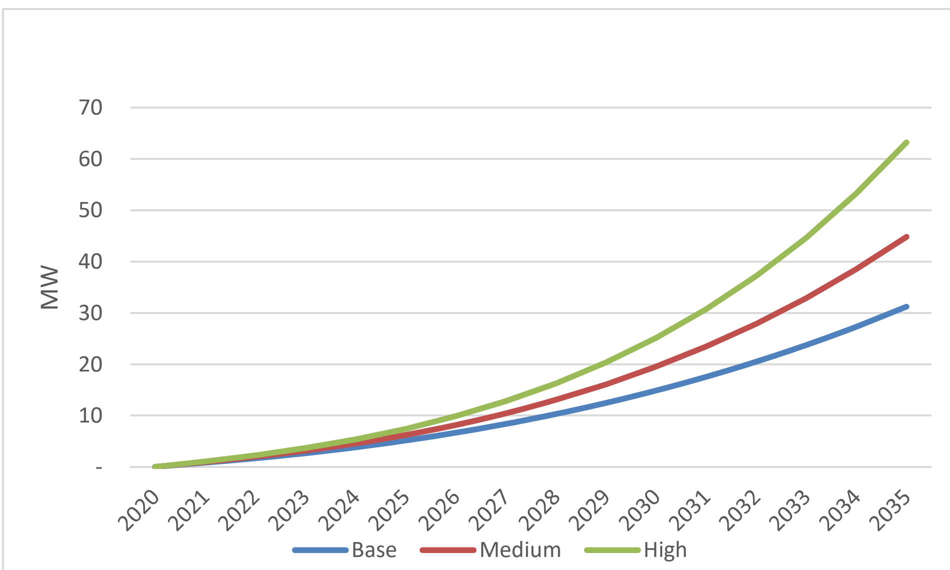

Table 7: Total Distributed Generation under three Forecast Scenarios

DG Solar Capacity (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	4.5	5.4	6.3	7.2	8.4	9.7	11.2	12.9	14.8	17.0	19.4	22.1	25.1	28.3	31.9	35.7
Medium	4.5	5.5	6.5	7.7	9.1	10.8	12.7	15.0	17.6	20.6	24.1	28.0	32.4	37.4	43.1	49.4
High	4.5	5.6	6.8	8.2	9.9	12.0	14.4	17.3	20.8	24.9	29.7	35.2	41.7	49.2	57.8	67.8

2. Home Electric Vehicles Charging

Minnesota Power recognizes the potential load growth that could result from this new electric end-use and has incorporated an outlook for Electric Vehicle adoption into the residential energy sales and peak demand forecasts. The Company projected residential passenger EV (light-duty vehicle) adoption based on a national-level outlook[29] that's been scaled to the Minnesota Power region. The energy and demand requirements of EVs adopted in the forecast timeframe (2021-2035) are added to the energy sales and peak demand outlooks. The effects of currently-owned EVs are presumed to be embedded in the econometric forecast.

The Company estimates there are about 330 light duty EVs (i.e. passenger vehicles) in Minnesota Power's retail service territory.[30] This equates to a 0.17 percent penetration rate. This level of vehicle ownership translates to an estimated 840 MWh of annualized energy consumption and represents just 0.08 percent of all sales to residential customers.

The Company projects that, by late 2030, just over 1.6 percent of regional vehicle ownership, and Minnesota Power will be the primary electric service provider to about 3,200 EVs. This equates to about 7,600 MWh in additional energy requirements from the residential sector and an estimated increase of 1 MW and 3.6 MW in the 2030 summer and winter peaks (respectively).

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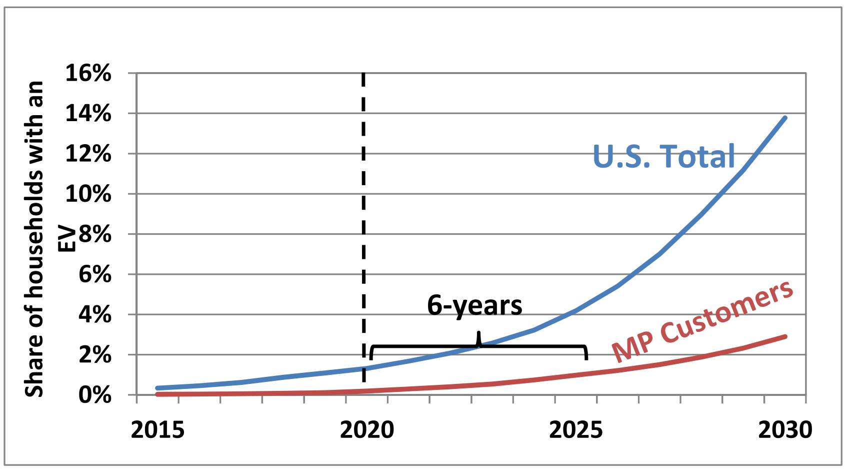
[29] Bloomberg 2020 Electric Vehicle Outlook (https://bnef.turtl.co/story/evo-2020/page)

[30] As of October 2021

This outlook assumes Minnesota Power customers' EV penetration and adoption continues to lag the overall trend in the United States by about 6 years. The Company attributes this lag in adoption to a variety of factors discussed in the Company's EVSE filing.[31] While Minnesota Power customers may "catch-up" to the rest of the country in EV adoption naturally, the Company has taken an active role in helping to support the adoption of the electric vehicle market. Refer to the Company's 2021 AFR for more detail on the base case scenario forecast or for a complete description of the methodology and data sources used to develop the outlook.

Figure 14: Electric Vehicle Saturation

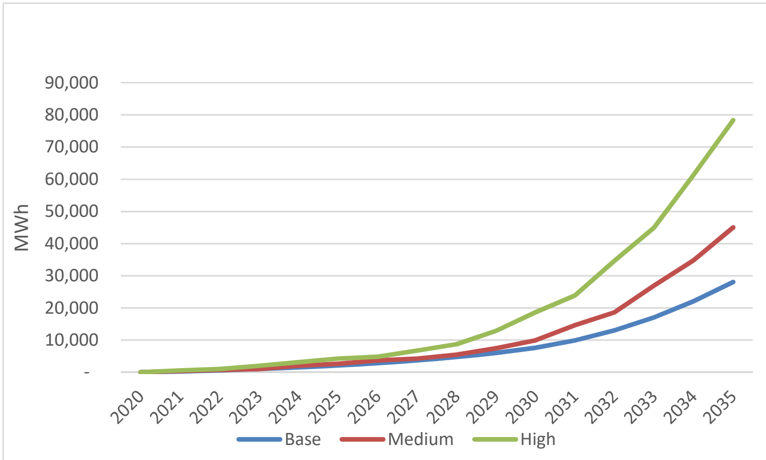


The medium and high scenarios differ from the base case outlook in how quickly Minnesota Power customers' EV penetration levels "catch-up" to the national average over the course of the forecast. In the medium scenario, Minnesota Power's assumed EV penetration levels are only 4.5 years behind the national average by 2030, and remain 3.5 years behind the nation by 2035. In the high scenario, Minnesota Power's EV penetration level remains about 4 years behind the nation by 2030, about 2 years behind the national average by 2035, and fully catches up to the national average by 2040.

[31] Docket No. E015/M-21-257

The outlooks for energy consumption under the three scenarios is shown below in Figure 15.

Figure 15: Residential EV Consumption (MWh)

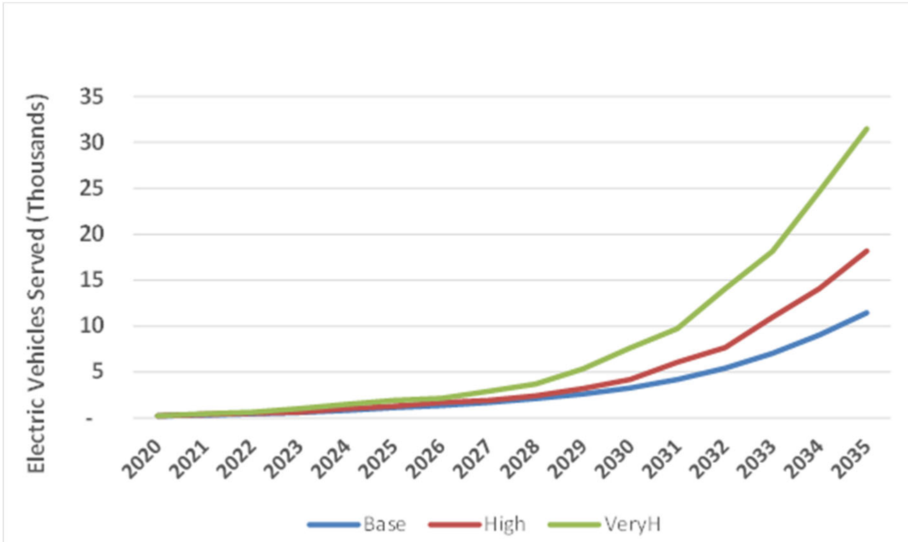


Under these higher adoption scenarios, Minnesota Power customers own between 4,200 and 7,600 EVs by 2030, which would represent 2.1 to 3.8 percent of regional vehicle ownership. This equates to about 10,000 to 19,000 MWh in additional energy requirements from the residential sector, an estimated increase of 1.2 to 2.3 MW in summer peak, and an estimated increase of 5.4 to 8.7 MW in the winter peak. The estimated peak impacts of EV adoption do not incorporate the assumed effects of TOD rates; this will be incorporated in next year's annual load forecast (AFR 2022).

3. Commercial (Public) EV Charging

Fleet vehicles and commercial charging are not addressed in AFR 2021. Fleet EV adoption in Minnesota Power's territory is too limited to gauge the pace of organic adoption or draw meaningful parallels between local and national adoption rates.

Figure 16: Electric Vehicle Adoption



However, public EV charging was projected as part of the Company's analysis for its April 8, 2021 DCFC Infrastructure filing.[32] Because the filing's outcome was uncertain during the 2021 IDP development timeframe (prior to Commission approval in late September 2021), forecast for load and energy added as a result of these public charging stations was excluded from the base IDP forecast. However, these forecasts of public charging station demand were included in two higher adoption 2021 IDP scenarios.

Minnesota Power's DCFC Infrastructure filing includes the construction of 16 DCFC stations within Minnesota Power's service territory ranging from 50 kW to 350 kW in capacity. The number of charging sessions and overall usage on each proposed charger was estimated by Minnesota Power using regression analysis. The Company leveraged two years of usage data at 12 existing DCFC stations, and analyzed how usage varied among these 12 stations according to three variables: proximate traffic, non-Tesla EV ownership (county), and employment (city). These three variables explain about 40 percent of the variance among 12 distinct stations located in both urban and suburban areas.

[32] Docket No. E015/M-21-257

The Company then gathered traffic, EV ownership, and employment information on each of its anticipated locations, and modeled the number of sessions and overall usage at each location as if they had been operating in 2019.[33] This estimate of 2019 charging sessions and usage was escalated per the Company's forecast of regional EV adoption as filed in its 2021 AFR.

The resulting estimates suggest the 16 DCFC stations will add about 1,300 MWh of energy use by 2030, and contribute about 0.2 MW to Minnesota Power's 2030 summer peak. By 2035, the 16 DCFC EV charging stations would add about 3,300 MWh of annual energy use and about 0.5 MW to summer peak demand. Table 8 below shows the projected annual energy consumption by these 16 DCFC EV charging stations under each of the three forecast scenarios.

Table 8: Projected Annual Energy Consumption

Energy Consumed (MWH)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	.	.	.	.	.	.	.	.	.	.	.	.	.
Medium	232	322	427	524	653	818	1013	1265	1619	2097	2519	2859	3259
High	232	322	427	524	653	818	1013	1265	1619	2097	2519	2859	3259

Summer Peak Impact (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	.	.	.	.	.	.	.	.	.	.	.	.	.
Medium	0.04	0.05	0.06	0.08	0.10	0.12	0.15	0.19	0.24	0.32	0.28	0.43	0.49
High	0.04	0.05	0.06	0.08	0.10	0.12	0.15	0.19	0.24	0.32	0.28	0.43	0.49

The forecast for load and energy added as a result of these public charging stations was excluded from the base 2021 IDP forecast, but is included under the medium and high 2021 IDP scenarios. Both the medium and high scenarios leverage the same outlook for public charging load.

4. Residential Time-of-Day Rate

Time of Day residential rate impacts are also captured in 2021 IDP scenario planning. The Company's recently approved Petition for Approval of Changes to

[33] The Company modeled only the 2019 usage data since 2020 travel was notably impacted by COVID19.

Minnesota Power's Residential Rate Design[34] included several prospective rate designs. The approved rate option features a roughly 2:1 on-peak to super off-peak price ratio, and an on-peak period lasting from 3 PM to 8 PM on weekdays, which encompasses the most common summer and winter peak times. The associated rate specifications are shown in Table 9 below.

Table 9: Final Alternative TOD Rates for 2020 Bill Impact Analysis (cents/kWh)

Standard *(Applicable to all customers not eligible for the Low-Income Usage Qualified Discount)*	**Updated 2019 Option 2 (Ratio ~2:1)**
Peak	14.9
Off-peak	10.7
Super off-peak	7.6
Peak period hours	3:00 PM – 8:00 PM weekdays
Off-peak period hours	All other times
Super off-peak period hours	11:00 PM – 5:00 AM

Low-Income Usage Qualified *(Applicable to customers eligible for discount)*	**Updated 2019 Option 2**
Peak (0-600 kWh)	11.7
Peak (601+ kWh)	14.9
Off-peak (0-600 kWh)	7.5
Off- Peak (601+ kWh)	10.7
Super off (0-600 kWh)	4.3
Super off (601+ kWh)	7.6

**Rates include cost of fuel and purchased energy. Rates are also subject to changes from general rate case proceedings or approved cost recovery riders.*

The Company then conducted an elasticity[35] analysis using peak period pricing and observed customer load behavior from its existing TOD Pilot participants. Based on

[34] Docket No. E015/M-20-850, Docket No. E015/M-12-233

[35] Elasticity (price elasticity of demand) measures the percent change in electricity demand resulting from a percent change in price.

this data, the Company estimates a price elasticity of about -0.35, i.e. a 10 percent increase in the price of electricity led to a 3.5 percent decrease in quantity demanded.

This -0.35 elasticity estimate was applied to the on-peak price under "Updated 2019 Option 2;" where the on-peak price (14.43 cents/kWh[36]) reflects a roughly 39 percent increase over base residential rates (10.77 cents/kWh[37]). According to this analysis, it would result in an estimated 12 percent reduction in on-peak energy usage. This estimated percent reduction is applied to residential customer use profiles to approximate the overall demand reduction of about 0.13 kW per-customer during an on-peak period. Overall system demand reduction is dependent on TOD participation rate; at 100 percent participation, the Company would expect a peak demand reduction of 15-16 MW. Table 10 below shows the summer peak demand reduction under each of the three scenarios.

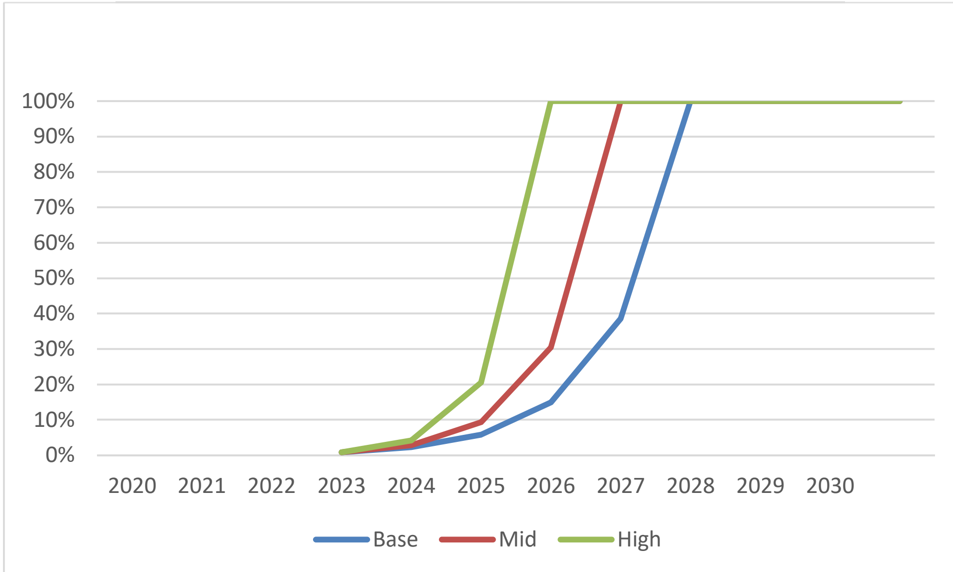
Table 10: Summer Peak Demand Reduction

Summer Peak Impact (MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base	(0.1)	(0.3)	(0.9)	(2.3)	(6.0)	(15.5)	(15.6)	(15.6)	(15.7)	(15.7)	(15.7)	(15.8)	(15.8)	(15.8)
Medium	(0.1)	(0.4)	(1.4)	(4.7)	(15.5)	(15.6)	(15.6)	(15.6)	(15.7)	(15.7)	(15.7)	(15.8)	(15.8)	(15.8)
High	(0.1)	(0.6)	(3.2)	(15.5)	(15.5)	(15.6)	(15.6)	(15.6)	(15.7)	(15.7)	(15.7)	(15.8)	(15.8)	(15.8)

The 2021 IDP evaluated three scenarios for TOD that vary in their assumed rates of residential customer participation. The Company's Residential Rate Design filing proposed a schedule for transitioning all residential customers to TOD as a default rate by 2025-2027. Figure 17 on the next page shows that all three scenarios adhere to this timeline and differ only in the pace of TOD adoption/participation by Minnesota Power's residential customers: the base TOD scenario assumes 100 percent participation by 2027, the "Mid" or Medium case assume full participation by 2026, and the high case assume 100 percent participation by 2025.

[36] Accounts for share of customers receiving the low income discount.
[37] FERC Form 1 2019, pg 304, column f "Revenue Per KWh Sold" for rates 20, 22 Residential

Figure 17: TOD Participation Rate by Scenario



5. Impact of Increased DER Adoption Rates on Planning Processes and Tools

Minnesota Power's current processes and tools for distribution planning and interconnection analysis are tailored to current distribution planning needs. Regular distribution planning assessments focus on peak or minimum load model snapshots and reliability issues such as phase balancing, capacitor placement, capacity, voltage support, and contingency analysis. Distribution generation interconnection requests are screened per the MN-DIP requirements and in-depth studies are conducted as needed. Based on these evaluations and Minnesota Power's TSM, network upgrades and interconnection facilities are identified where needed for distribution generation interconnections on a case-by-case basis.

Increased adoption of distributed energy resources will impact both of these planning processes. Regular distribution planning assessments will become more complex, and identifying the location and characteristics of individual DERs or groups of DERs on a feeder will become necessary to adequately evaluate the system. Pockets of aggregated DERs will need to be evaluated as part of regular planning assessments to understand their impacts on feeders and substations. Additional analysis will be required to identify load and generation conditions that may stress the system, and additional models will likely have to be evaluated beyond the traditional peak and minimum load models. Such analysis may require new modeling tools beyond the traditional snapshot-in-time models that Minnesota Power presently utilizes, perhaps to the point where models are needed to simulate hourly DER and load characteristics or transient switching impacts. For each additional system condition and each new type of analysis, the time and resources required to build the models and complete the analysis will increase.

As DER adoption grows, more direct impacts are expected on the processes and tools required to manage distributed generation interconnections. A substantial increase in the volume of interconnection requests would create additional administrative and technical work as the requests are processed and studied. More individual interconnection requests will likely fail the MN-DIP screens and require detailed technical analysis, due to the amount of DERs already connected to the feeder or the size of the individual DERs. Increasing complexity on the distribution system may lead to additional technical analysis that is not presently needed on a regular basis for distribution generation interconnection studies – such as electromagnetic transient studies and control system coordination studies – to ensure that DERs do not have a negative impact on end-use customers or other connected generators. Additional modeling programs or additional technical consultant studies may be required to perform this work. Minnesota Power will have to expand its engineering resources, modeling and evaluation tools, and technical expertise as DER adoption grows significantly beyond recent adoption rates on the distribution system.

6. Institute of Electrical and Electronic Engineers ("IEEE") Std. 1547-2018[38] Impacts

Minnesota Power closely monitors advances in inverter technology via participation in the Distribution Generation Working Group, conversations with customers and installers, and various other industry groups. The vast majority of the DERs on

[38] https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/IEEE%20SCC21_1547_Overview_NERC_SPIDERWG_01072019.pdf
https://www.cooperative.com/programs-services/bts/Documents/Reports/NRECA-Guide-to-IEEE-1547-2018-March-2019.pdf

Minnesota Power's system are quite small and adoption is primarily driven by the SolarSense rebate program. Since the 2019 IDP, Minnesota Power has filed and implemented its first Technical Specifications Manual and the primary deviation from previous practices in terms of inverters setting was moving to a 0.98 power factor as a default.

Since 2019, there has been one instance in which the Company has explored using different inverter modes to mitigate impacts to the distribution system. This project is still ongoing and all options are being explored with the developer. Minnesota Power maintains that in the future there are potentially other control modes that may prove useful, but current penetration levels are low enough where they do not have much of an impact on power quality or reliability in most cases.

While Minnesota Power's overall DER penetration level is low, there are a handful of feeders on which the penetration is high relative to the load. Minnesota Power presently has three feeders, Blanchard 508 feeder, Wrenshall 411 feeder, and Platte River 546 feeder, which have solar installations with a nameplate capacity greater than or equal to the feeder's daytime minimum load. The Blanchard 508 feeder circuit includes Camp Ripley, which has installed approximately 10 MW of nameplate solar behind the meter. This feeder circuit has a daytime minimum load of only 2.06 MW. On the Wrenshall 411 feeder circuit, Minnesota Power has a 1.00 MW nameplate solar garden. This feeder has a daytime minimum load of 1.00 MW. The Platte River 546 feeder circuit includes three large customer-installed solar arrays with a cumulative nameplate output of 1.75 MW. This feeder has an estimated daytime minimum load of 0.50 MW.

Over the years, Minnesota Power has experienced a number of relatively small issues related to customer solar installations. As discussed in the 2019 IDP, Minnesota Power had to adjust the taps on a transformer for its own 40 kW solar garden. In the last two years, two customers experienced issues with their inverters tripping offline unexpectedly. The Company was able to identify a loose neutral connection and a failing transformer in both of those cases respectively.

Processes and tools continue to evolve as the DER landscape changes. Over the past two years more exploratory pre-application report requests have been received than ever before and the Company anticipates that the demand for DER, and especially large-scale solar, will increase. This will further impact planning resources and the tools employed. Minnesota Power is continuing to improve use and knowledge of EPRI DRIVE for hosting capacity. DRIVE is a promising tool and it is the Company's hope to use it more broadly over the next few years, especially as small-scale installations continue to be concentrated on a few substations in Duluth.

D. Historical Loading and Preliminary Hosting Capacity Data

The Company currently does not perform hosting capacity analysis but is moving towards being able to do so on a targeted basis through its involvement in the EPRI DRIVE User Group. Peak load information is gathered annually in order to perform baseline planning studies on the distribution system. The Company's peak coincident load for the distribution system (as measured between the transmission and distribution system) was 636 MW on February 13, 2020 at 8:00 AM. This information is taken from hourly historical loading data collected between January 1, 2020 and December 31, 2020.

As historical peak load information was evaluated by feeder and substation for the 2019-2020 time period, daytime minimum load as well as average loading were evaluated where historical data was readily available. Where direct historical data points are not available, daytime minimum load is assumed to be 20 percent of the peak load for a feeder. Tables showing peak, daytime minimum, and average load by substation, parent feeder, and stepdown feeder for 2019 and 2020 are provided in Appendix E. In general, "Substations" are inclusive of all parent feeders connected to a substation. "Parent feeders" are inclusive of load directly connected to a feeder and any stepdown transformers connected to the feeder. "Stepdown feeders" are inclusive of load that is directly connected to a feeder that is served from a stepdown substation connected to a parent feeder, which is generally of a higher voltage class than the stepdown feeder.

E. <u>DER System Impacts and Benefits</u>

Minnesota Power continues to investigate DER options as part of its broad utility planning process to consider non-wires alternatives. Applications such as solar and storage continue to be explored in this broad planning effort. The opportunities are considered in collaboration with the Company's resource, transmission, and distribution planning teams.

As these alternatives begin to demonstrate broader application for the system, it will be necessary to integrate and provide visibility through software, tools and communication infrastructure. The Company will provide a general overview of current impacts and benefits in the sections below.

1. EV Impacts

Electric Vehicles present vast potential benefits for most utilities. However, if the charging infrastructure is unmanaged, it has the potential to cause costly impacts to the distribution system. For example, customers installing Level 2 home charging equipment, with about 10 kW of load, can put stress on transformers or cause line voltage issues. This is particularly true if many homes begin installing chargers and then charge at the same time. However, if monitored through advanced metering infrastructure and/or smart chargers, these loads could be managed effectively. With the current penetration level of EVs in Minnesota Power's service territory, the Company has not experienced any of these issues to date. It is prudent to consider customer programming that encourages and incentivizes customers to install smart chargers, which can be effectively utilized in conjunction with off-peak EV rate structures. In addition, utilities, in general, must continue to develop internal expertise, software systems, and protocols for engaging with these new DERs.

There are additional potential benefits related to EVs as they gain the ability not only to charge, but to discharge onto the system. This is an emerging area that will require significant investment in regulations, software platforms, charging equipment, and equitable rate structures. Minnesota Power, as highlighted in previous sections, is taking the first steps to provide a base for new rate structures and customer interactions through its internal EV efforts, system integrations and C2M implementation.

2. Solar PV Impacts

Solar is being deployed on widely varying scale from street lights to utility scale power plants. It offers many values to the distribution system while also presenting some challenges. The value of small-scale solar is that it may offer resiliency to the system if deployed in a distributed manner. Geographically dispersed solar arrays avoid taking large amounts of generation offline during various meteorological events like cloud cover and storms. In addition, during outages, geographically dispersed and well-designed distribution systems may be able to isolate and repower sections not directly affected by system outages. An example may be a solar powered retail center or housing development designed to isolate itself during an outage event. The potential cost and benefits of these systems still require many resources and extensive research to determine the best path forward and socialized benefits have yet to be well defined.

The cost and benefits of any programmatic planned system wide deployment of solar will require ongoing analysis with input from many stakeholders. The cost of deploying small-scale solar arrays for specific segments of the distribution system versus larger centralized solar plants must be weighed against the benefits of having generation sources closer to load centers along with initial capital costs, ongoing fleet maintenance and operational costs. The benefits are not currently well understood on a case-by-case basis for most utilities. This will require clear policy frameworks for leveraging resources to investigate and plan for DER integration in a well-managed and advantageous manner.

The primary technical concern with distributed solar PV is the potential for reverse power flow at the feeder-level. Historically, the distribution system has been designed for unidirectional power flow from the substation breaker to consumer loads. Bi-directional and reverse power flow conditions could negatively impact feeder voltage and system equipment that has been designed for, and is protected by schemes designed for, unidirectional flow. For individual DER installations, the potential impacts are examined during the interconnection process. The Company has already experienced some system impacts from small-scale solar installations, such as having to modify regulator settings on a feeder to account for a potential reverse power flow condition. Increasing penetration levels over the planning horizon will likely result in more feeders with reverse power flow conditions. Future mitigation options may include utilizing advanced inverter options.

3. Barriers to DER Integration

At present there are few incentives for utilities and businesses to work together on a holistic system-wide approach to DER integration. Without net metering and tax incentive programs, new DER developments aren't currently cost effective for most customers. For example, one barrier to DER integration is the high cost of entry. Developers and customers who want to interconnect to the distribution system bear all costs for upgrades required to accommodate the proposed interconnection. Because of this, there may be some developers or customers who choose not to pursue interconnection.

Extended timeframes for program development and technology implementation are also barriers to deployment. An example is the Company's current efforts to modernize its metering infrastructure. Until the meter rollout is complete, it is not possible to fully realize the many potential benefits and programs enabled by advanced metering and the development costs tend to be high for these types of programs. Along with this, how various DER technologies like wind, solar, EVs, and storage will all work in tandem on the grid will require significant analysis, planning and stakeholder interaction.

4. Federal Energy Regulatory Commission Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators)

Federal Energy Regulatory Commission ("FERC") Order No. 841 established reforms to remove barriers to the participation of electric storage resources in the Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") markets. FERC found that RTO/ISO market rules employed obstacles for electric storage resources to participate in the market. An excerpt from the Order follows:

> "direct[s] regional grid operators to remove barriers to the participation of electric storage in wholesale markets. By directing the regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, the Order affirms that storage resources must be compensated for all of the services provided and moves toward leveling the playing field for storage with other energy resources. Order 841 creates a clear legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs."[39]

Minnesota Power generally supports FERC Order 841 in regards to transmission level storage assets. However, the Company has reservations in regards to the treatment of distribution connected battery storage and DERs. The ability of electric storage resources to participate in the wholesale market at the distribution level and behind the meter will have implications for local distribution operators. In particular, the provision of Order 841 that encompasses DER resources, not just battery storage, is problematic. There are metering, operational, and wholesale market issues that arise due to the possible participation of DERs in wholesale RTO or ISO markets.

As a result, Minnesota Power would most likely file a tariff with FERC to address DER participation in wholesale markets. At a high level these tariffs would address distribution system upgrade costs, metering capability, reliability assurance mechanisms, and cost recovery.

[39] http://energystorage.org/policy/regulatory-policy/overview-ferc-order-841

SECTION V:

Conclusion

V. CONCLUSION

Minnesota Power's 2021 IDP provides an overview of the Company's current distribution planning processes and future investment plans. Historical spend and planning has positioned the Company for a seamless transition to an innovative future to meet customers' needs and expectations. The foundational investments are built upon the Company's Core Values and distribution strategy of technology, innovation, and continuous learning. The Company has demonstrated these values by focusing on right time, right fit investments and by thoughtfully leveraging internal and external resources in a cost conscious manner to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid.

The results of this customer focused, thoughtful planning process are evidenced by Minnesota Power's leadership in the state of Minnesota in AMI implementation, exceedance of the state's energy savings goals year-over-year, and piloting of innovative rate structures such as TOD. These initiatives are coupled with the lowest residential rates in Minnesota and the Company's steady progress towards carbon reduction and increased renewable generation. The Company is now delivering 50 percent renewable energy to customers, with the goal to be completely carbon free by 2050. Minnesota Power is thoughtfully moving fast in transforming its energy supply.

Moving towards the future, Minnesota Power is executing its distribution plan, focusing ongoing efforts to support customers, communities, the climate, and the Company. Above all else, customers expect reliable, affordable, and safe electric service, all of which are encompassed in Minnesota Power's distribution values. The thoughtful system investments currently taking place provide a foundation for Minnesota Power to continue advancing innovative customer programming, along with additional investment in grid modernization pilots and initiatives. The investments and programs outlined in this 2021 IDP will create greater customer engagement, empowerment, and options for energy services; and this connective model will support the development and integration of DER technologies and enhance the value of their application as it relates to grid operations. Minnesota Power is proud to share its vision for a resilient future through this 2021 IDP.

Dated: October 25, 2021

Respectfully Submitted,

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Section	Heading	PUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254; 05/27/20 Order in Docket No. E015/M-19-684)	Location
2	Stakeholders Meeting	Minnesota Power should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure that modifications to the MN-IDP can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Minnesota Powershould seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) the anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years, (3) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input	I.D.2, Appendix B
3.A.1	Baseline Distribution System and Financial Data: System Data	Modeling software currently used and planned software deployments	I.D.3, I.E.1-2; II.B, II.D.1-4; II.F.1, IV.B.3, Figure 4
3.A.2	Baseline Distribution System and Financial Data: System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	II.F.2
3.A.3	Baseline Distribution System and Financial Data: System Data	A summary of existing system visibility and measurement (feeder-level and time) interval and planned visibility improvements	II.F.1-2; II.G.1-2
3.A.4	Baseline Distribution System and Financial Data: System Data	Number of customer meters with AMI/smart meters and those without, planned AMI- investments, and overview of functionality available	I.E.1, II.D,4; II.F.1-2; III.A.1,5,8; IV.B.1, Figure 9, Table 3, 5
3.A.5	Baseline Distribution System and Financial Data: System Data	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	III.B, IV.C
3.A.6	Baseline Distribution System and Financial Data: System Data	Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology	III.B, IV.C.1-5; Table 7, 8, Figure 12, 13, 15, 16
3.A.7	Baseline Distribution System and Financial Data: System Data	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations	IV.C.6
3.A.8	Baseline Distribution System and Financial Data: System Data	Distribution system annual loss percentage for the prior year	Appendix D
3.A.9	Baseline Distribution System and Financial Data: System Data	The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring system	IV.D
3.A.10	Baseline Distribution System and Financial Data: System Data	Total distribution substation capacity in kVA	Appendix C
3.A.11	Baseline Distribution System and Financial Data: System Data	Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.	Appendix C
3.A.12	Baseline Distribution System and Financial Data: System Data	Total miles of overhead distribution wire	Appendix C

Section	Heading	PUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254; 05/27/20 Order in Docket No. E015/M-19-684)	Location
3.A.13	Baseline Distribution System and Financial Data: System Data	Total miles of underground distribution wire	Appendix C
3.A.14	Baseline Distribution System and Financial Data: System Data	Total number of distribution customers	I.B, Appendix C
3.A.15	Baseline Distribution System and Financial Data: System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category	II.A.4, Figure 8
3.A.16	Baseline Distribution System and Financial Data: System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred	II.A.4, Figure 8
3.A.17	Baseline Distribution System and Financial Data: System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type	Appendix C
3.A.18	Baseline Distribution System and Financial Data: System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type	Appendix C
3.A.19	Baseline Distribution System and Financial Data: System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type	II.A.1, Figure 6
3.A.20	Baseline Distribution System and Financial Data: System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type	Appendix C
3.A.21	Baseline Distribution System and Financial Data: System Data	Total number of electric vehicles in service territory	II.A.3
3.A.22	Baseline Distribution System and Financial Data: System Data	Total number and capacity of public electric vehicle charging stations	II.A.3
3.A.23	Baseline Distribution System and Financial Data: System Data	Number of units and MW/MWh ratings of battery storage	IV.B.6, Figure 6
3.A.24	Baseline Distribution System and Financial Data: System Data	MWh saving and peak demand reductions from EE program spending in previous year	II.A.5, Table 2
3.A.25	Baseline Distribution System and Financial Data: System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	II.A.2

Section	Heading	PUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254; 05/27/20 Order in Docket No. E015/M-19-684)	Location
3.A.26	Baseline Distribution System and Financial Data: Financial Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements (road-relocations, etc.) g. Metering h. Other	Figure 5, 11 Table 1
3.A.27	Baseline Distribution System and Financial Data: Financial Data	All non-Minnesota Power investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).	II.A.4
3.A.28	Baseline Distribution System and Financial Data: Financial Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	Figure 9, 11 Table 3, 4
3.A.29	Baseline Distribution System and Financial Data: Financial Data	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	II.D.1-5; II.E, II.F.2, IV.A Figure 11 Table 4, 5
3.A.30	Baseline Distribution System and Financial Data: Financial Data	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	II.D, III.C
3.A.31	Baseline Distribution System and Financial Data: DER Deployment	Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	II.A.1-5; Figure 6, 7
3.A.32	Baseline Distribution System and Financial Data: DER Deployment	Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers “high” DER penetration.	IV.C, 1-6; Figure 12, 13, 15-17; Table 7, 8, 10
3.A.33	Baseline Distribution System and Financial Data: DER Deployment	Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.	IV.C.6, IV.E.2
3.B.1	Preliminary Hosting Capacity Data	Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified)	IV.C.6, IV.D Appendix E
3.C.1	Distributed Energy Resource Scenario Analysis	Distributed Energy Resource Scenario Analysis 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 the distribution system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Minnesota Power distribution system in the locations Minnesota Power would reasonably anticipate seeing DER growth take place first.	IV.C, 1-6; Figure 12, 13, 15-17 Table 7, 8, 10
3.C.2	Distributed Energy Resource Scenario Analysis	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.	III.B, IV.C, 1-4

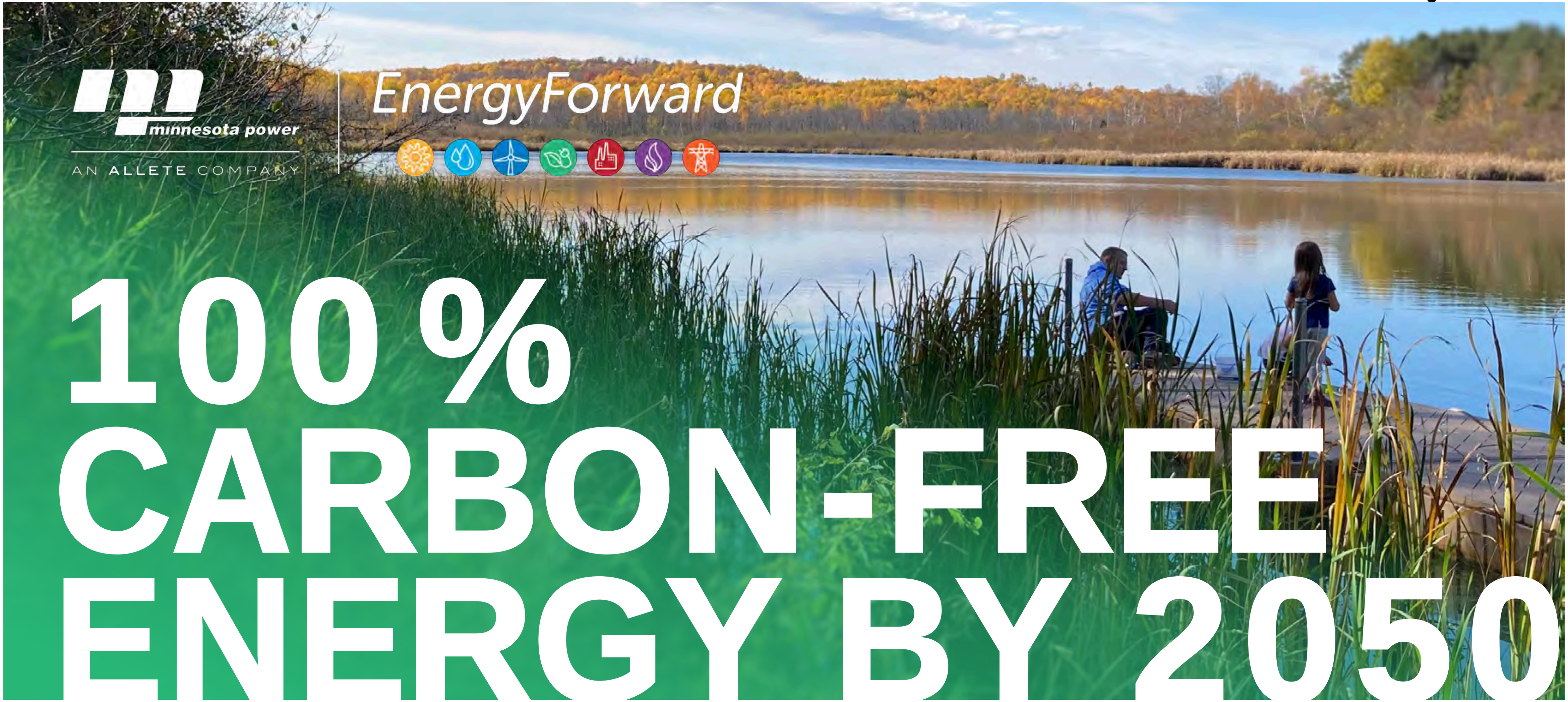
Section	Heading	PUC IDP Requirement (11/01/19 Order in Docket No. E015/CI-18-254; 05/27/20 Order in Docket No. E015/M-19-684)	Location
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	II.A.3, IV.C, IV.E.1-4
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM- 18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)	IV.E.4
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Minnesota Power shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis.	I.E,1; II, A.4-5; II.B, II.C, II.D, 1-5; II.F.1-2; II.G.1-2; III.A.1-8; IV.A, IV.B, 1-8; IV.E.2-4; Figure 9, 11 Table 3, 4, 9
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Minnesota Power shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Minnesota Power is currently using.	III.C, IV.A IV.C.1-5; Figure 4, 10-17 Table 7, 8, 10
3.E.1	Non-wires Alternatives Analysis	Minnesota Power shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	II.E, Table 4
3.E.2	Non-wires Alternatives Analysis	Minnesota Power shall provide information on the following: a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) b. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) c. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed d. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made	II.D, III.B, III.C, IV.B.5

Minnesota Power Integrated Distribution Plan
July 13, 2021

Webex Virtual Meeting

Agenda

10:00 am	Welcome, Introductions, Overview
10:10 am	IDP Presentation, followed by Q&A
12:00 pm	Wrap-up and Adjourn



Minnesota Power's 2021 Integrated Distribution Plan Stakeholder Meeting

July 13, 2021

OVERVIEW

- Welcome & Introductions
- Minnesota Power and its Distribution System
- Minnesota Power's 2021 Integrated Distribution Plan
  - Foundational Investments
  - Demonstrating Innovation
  - Planning for a Resilient Future
- Questions & Discussion

Welcome & Introductions

Minnesota Power & its Distribution System

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Over 115 Years Serving the Region

Construction on the Thomson Hydroelectric Station began in 1905.

By 1923, the company became known as Minnesota Power and Light

Boswell Energy Center started producing power in 1958.

Construction of the Bison Wind Energy Center was completed in 2015.

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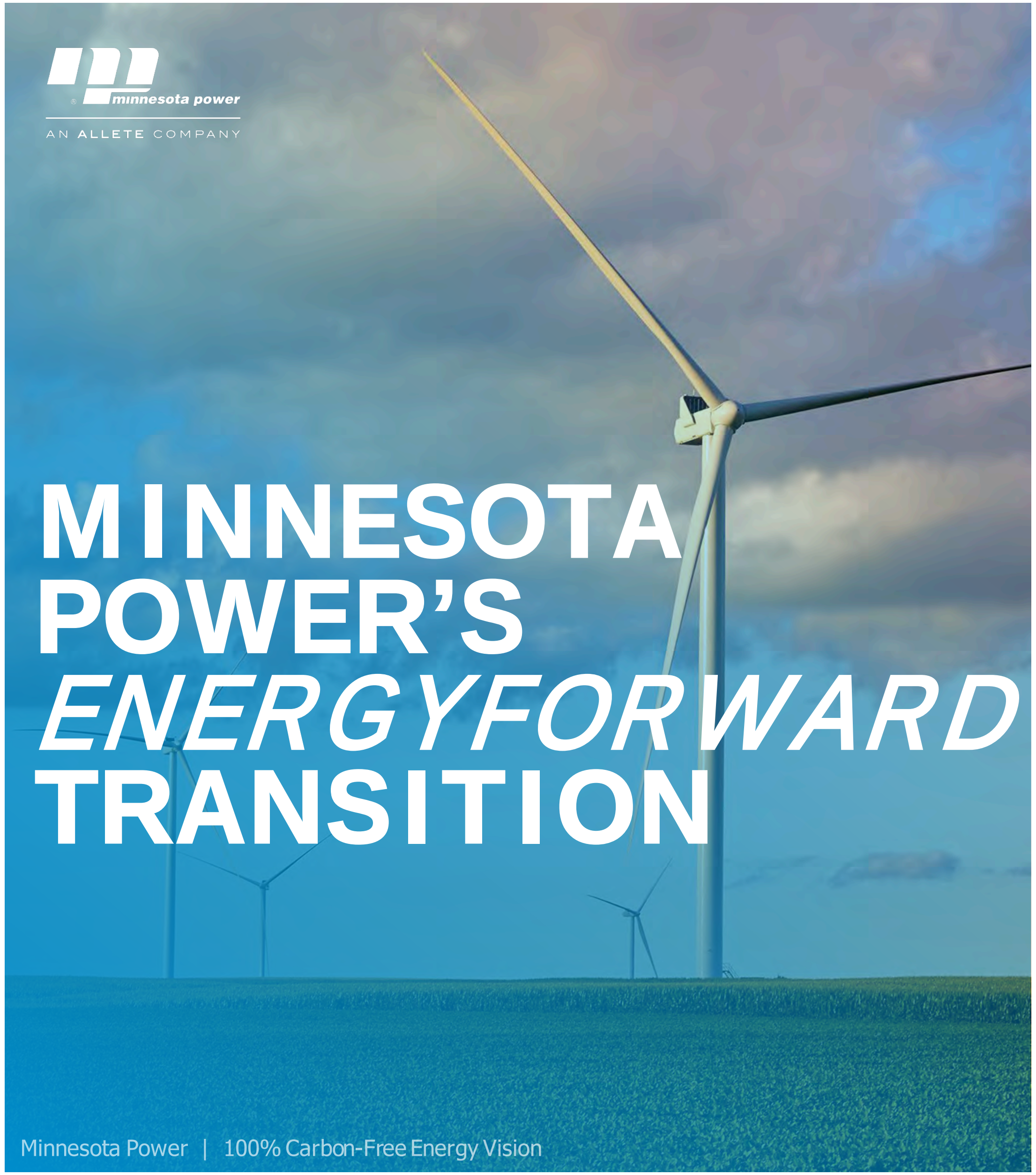
WE ARE UNIQUE

Duluth, MN Headquarters
26,000 Square-miles
145,000 Customers
13% Residential sales*
72% Industrial sales*
15 Minnesota Municipalities

Percentage of retail sales



Yesterday

Nine coal units

95% of energy from carbon sources

Today

First Minnesota utility to deliver 50% of energy from renewable sources

7 of 9 coal units closed or transitioned

50% reduction in carbon

Achieving state standards a decade early

Tomorrow

100% carbon-free energy by 2050

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A Just Transition for Northern Minnesota

Our commitment to climate, customers and communities

A sustainable carbon reduction plan must:

1. Ensure reliability
2. Manage costs for all customers
3. Time for just transition for employees and host communities
4. Allows time for technology to develop and advance

We have **exceeded state clean energy goals** without risking safety, reliability and affordability—and we will continue to do so.

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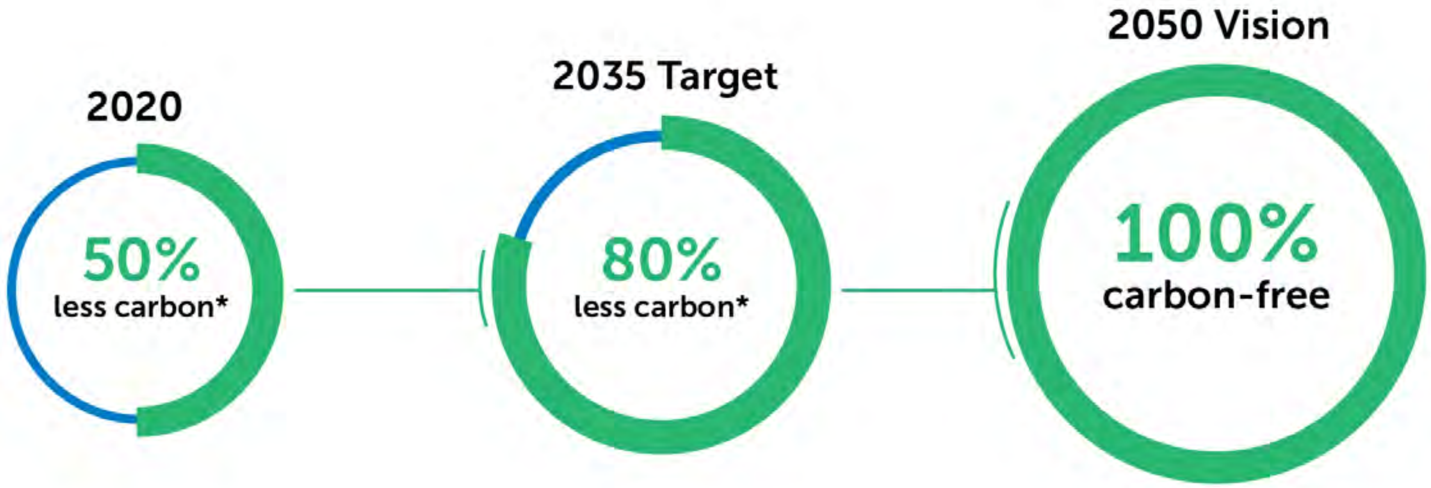
OUR 100% CARBON-FREE ENERGY VISION

We are committed to making a sustainable transition to a **reliable, affordable** and **carbon-free** energy mix for our customers.



*From 2005 levels

Strengthen the electric grid

Adopt innovative solutions

Engage with stakeholders

Collaboration with state of Minnesota and others to develop a sustainable transition plan for host communities.

Minnesota Power’s 2021 Integrated Distribution Plan

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Purpose of MN's Integrated Distribution Plan (IDP):

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility'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

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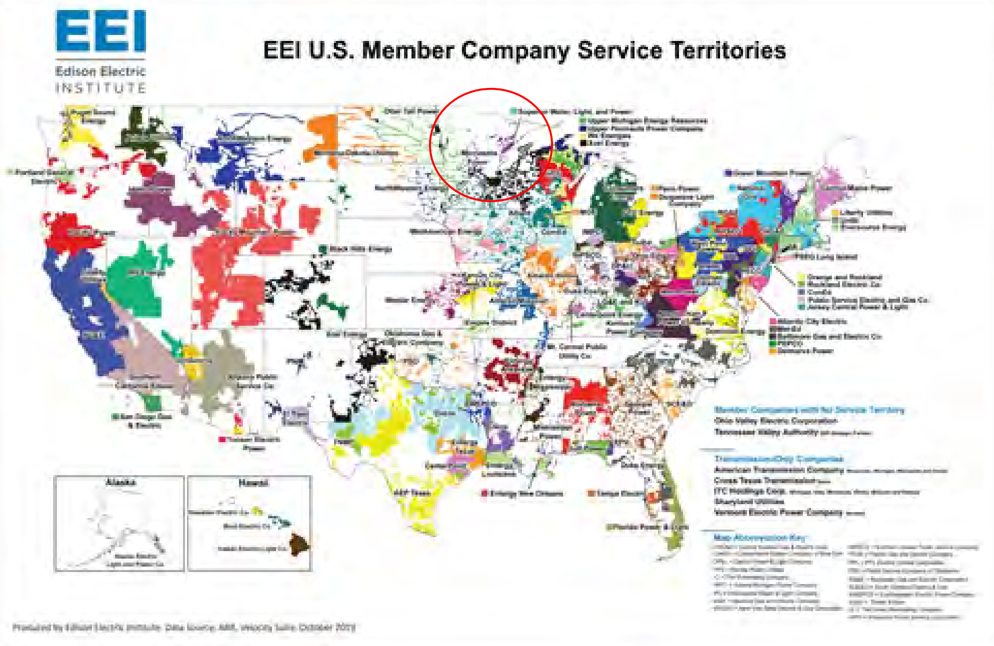
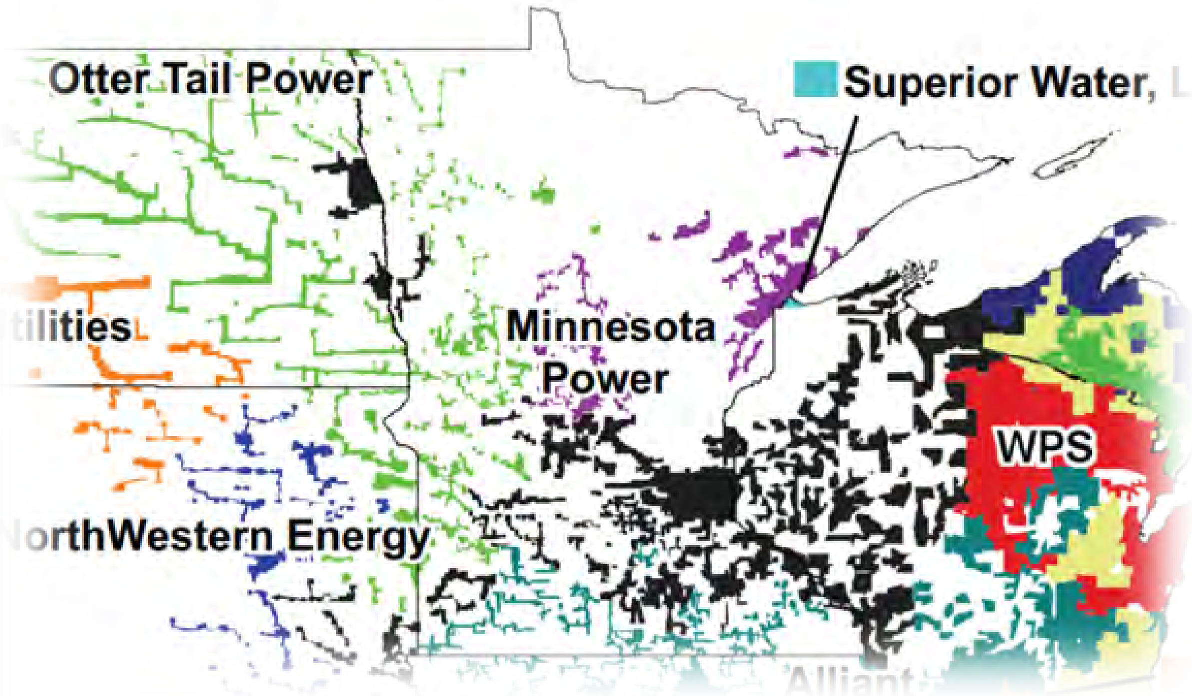
Elements of an IDP:

- Baseline Distribution System Data
- Baseline Financial Data
- Baseline DER Data
- Preliminary Hosting Capacity Data
- DER Scenario Analysis
- Non-Wire or Non Traditional Alternatives
- 5-10 Year System Modernization and Infrastructure Plan

Minnesota Power's Service Territory





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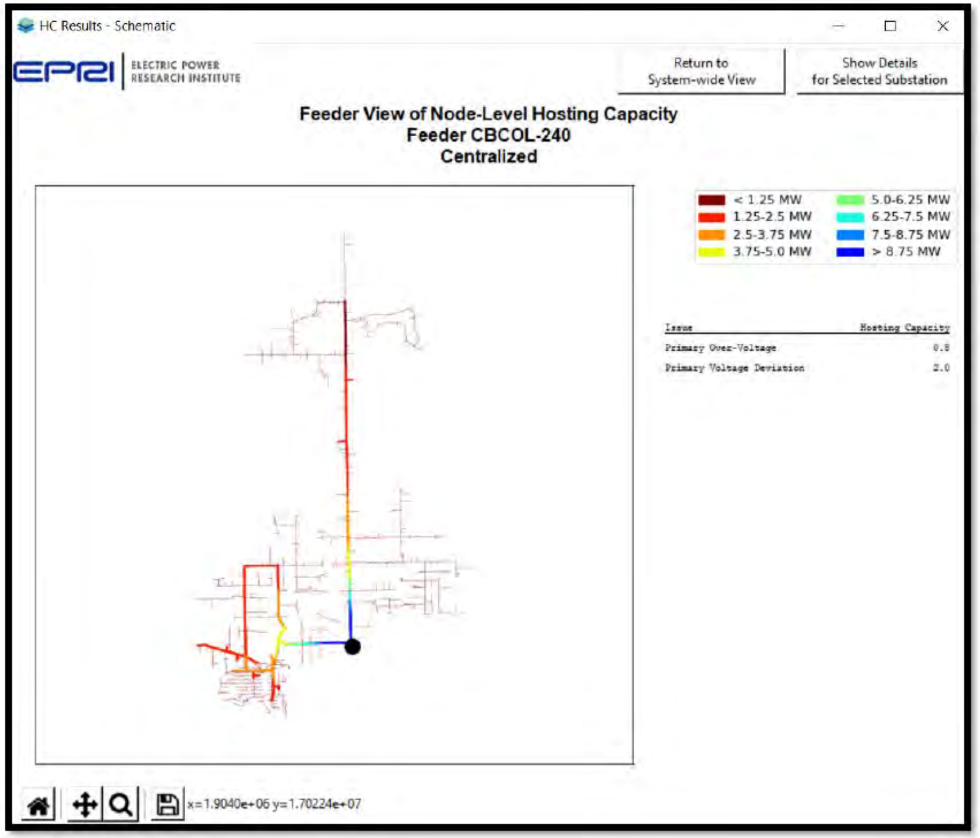
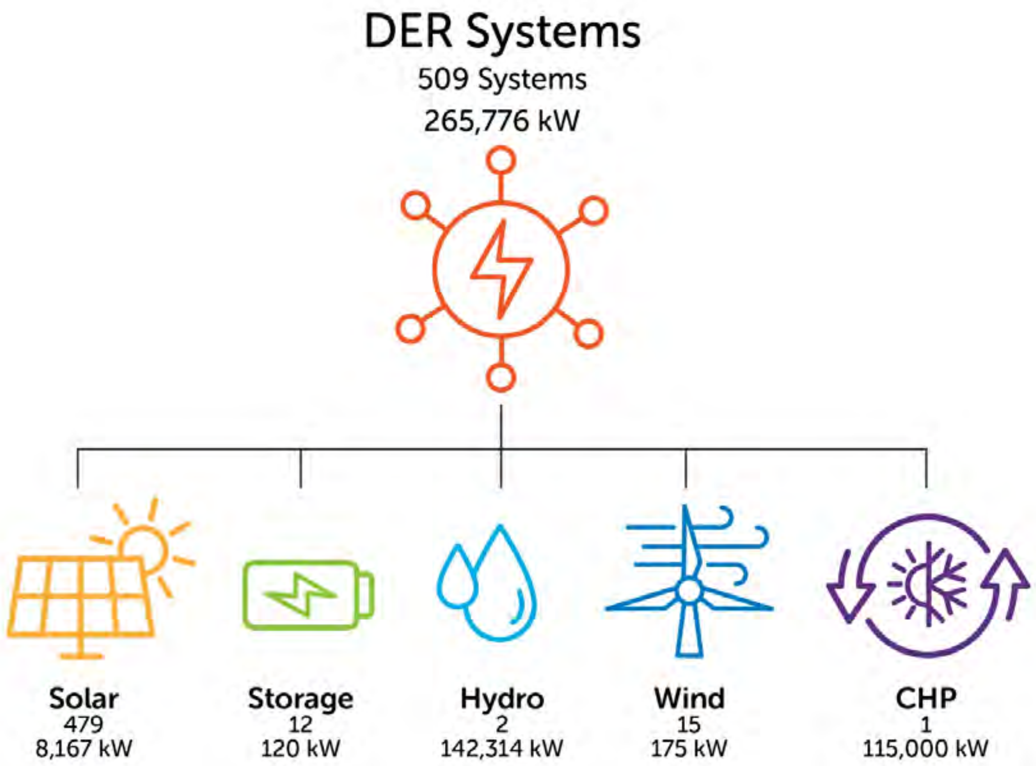
Preliminary Hosting Capacity

- MP does not currently perform hosting capacity analysis
- Moving towards being able to do so through involvement with the EPRI DRIVE User Group
  - Recently worked with EPRI to produce preliminary heat maps for a handful of feeders
- Annual peak and daytime minimum historical load data is evaluated regularly
  - Provides an input to baseline distribution planning & interconnection studies
  - 2019-20 data will be provided with the 2021 IDP

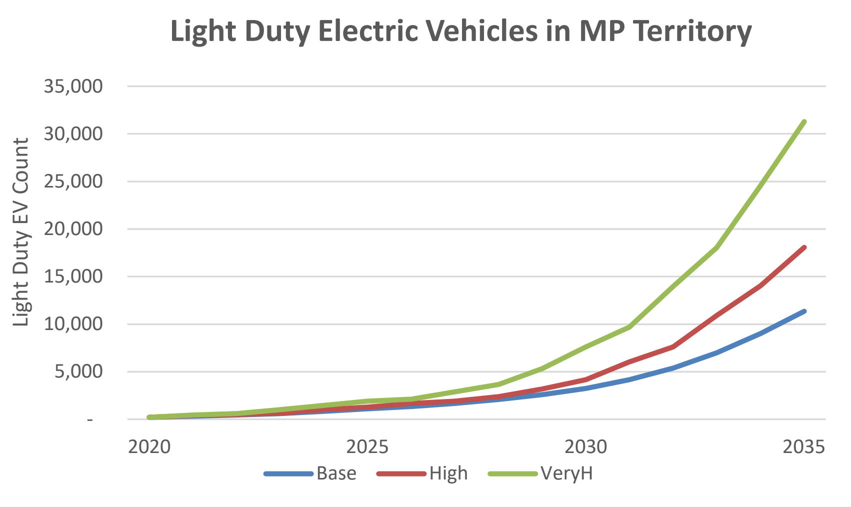


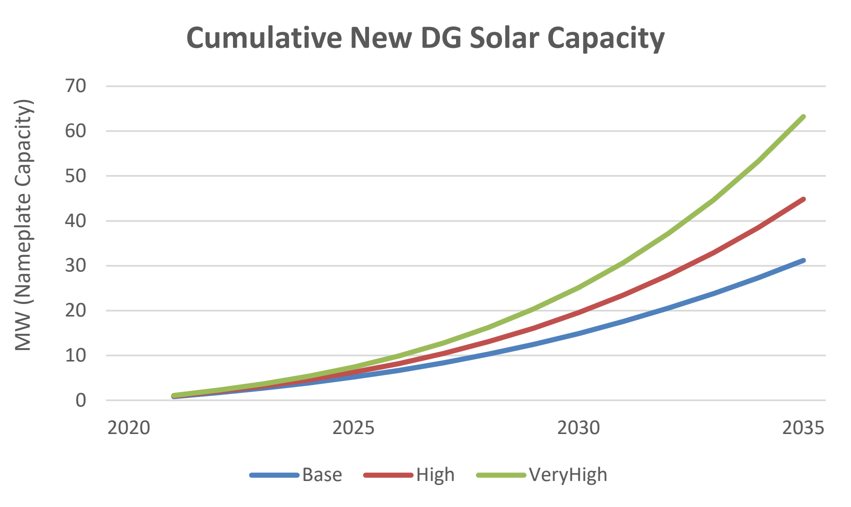
Distributed Energy Resources (DER) on MP's System



DER Scenario Analysis

- Scenarios consider:
  - Electric Vehicle Ownership (Home/Residential Charging)
  - Public Electric Vehicle charging
  - Distributed Solar Generation
  - Universal Residential Time Of Day (TOD) rollout
- **Base Case** – Consistent with 2021 IRP & 2021 AFR assumptions for Electric Vehicle ownership and distributed solar generation. Assumes full transition of Residential customers to TOD by 2027.
- **Medium DER** – Slightly accelerated adoption of EV and DG Solar, a transition to 100% TOD participation by 2026, and the installation of 16 new Direct Current Fast Chargers (DCFC) for Electric Vehicles on the Minnesota Power system beginning in 2023.
- **High DER** – Aggressively accelerated adoption of EV and DG Solar, 100% TOD participation by 2025, and the installation of 16 new Direct Current Fast Chargers (DCFC) for Electric Vehicles on the Minnesota Power system beginning in 2023.





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Foundational Investments

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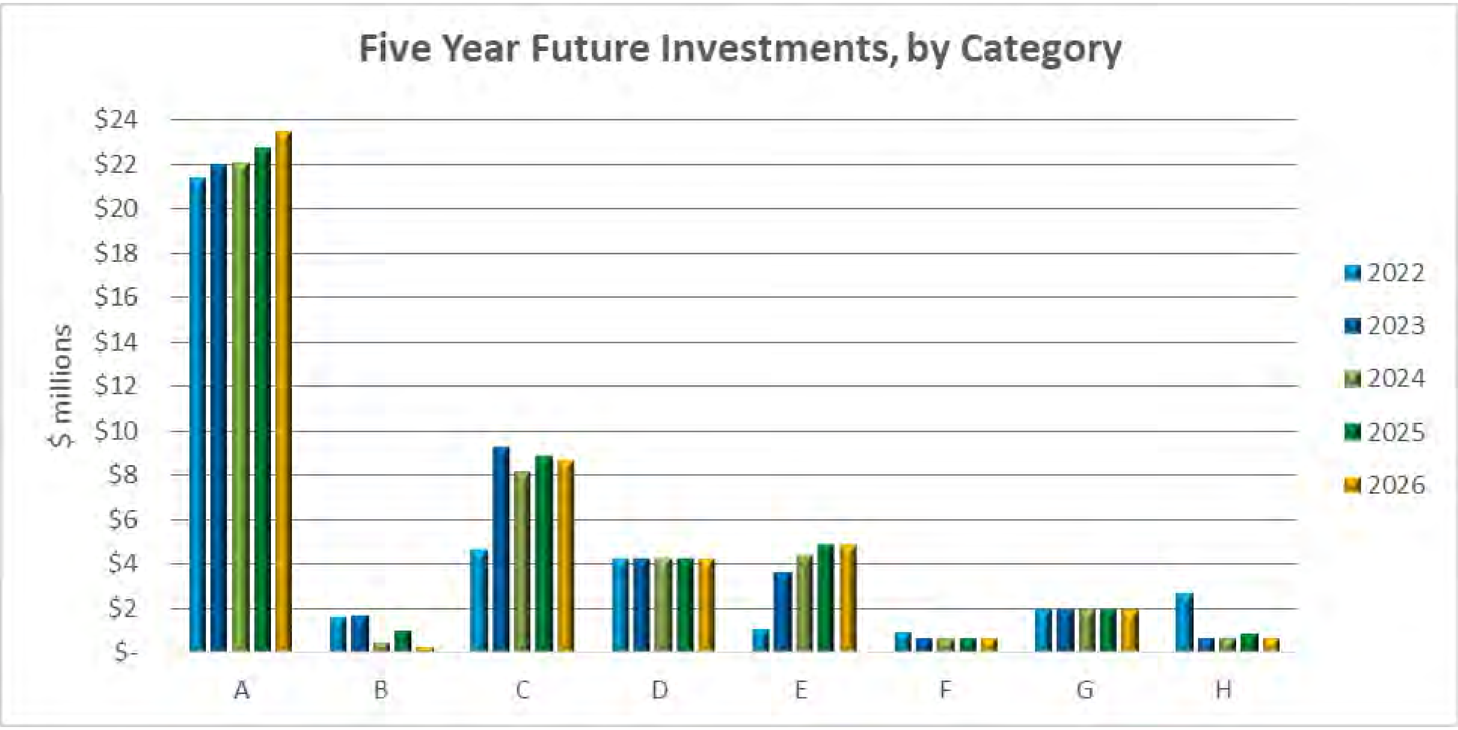
5-Year Investment plan



IDP Category

A - Age-Related Replacements and Asset Renewal

B - System Expansion or Upgrades for Capacity

C - System Expansion or Upgrades for Reliability and Power Quality

D - New Customer Projects and New Revenue

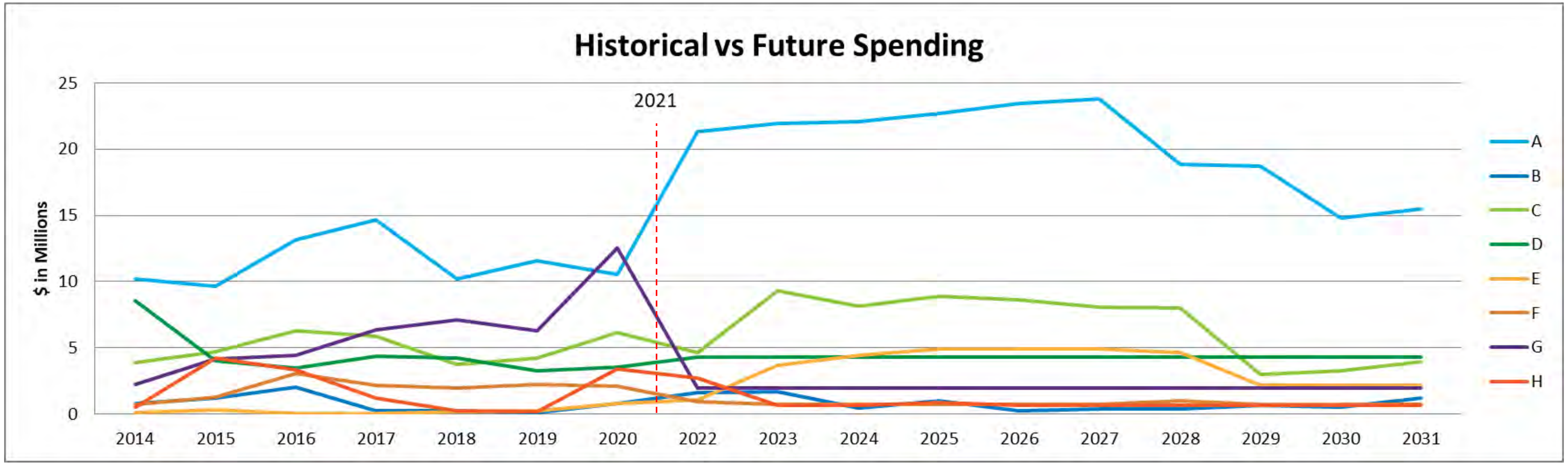
E - Grid Modernization and Pilot Projects

F - Projects Related to local (or other) government requirements

G - Metering

H – Other

Long-term Investment Plan



IDP Category	2014	2015	2016	2017	2018	2019	2020	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A - Age-Related Replacements and Asset Renewal	10.207	9.669	13.127	14.636	10.226	11.580	10.552	21.322	21.935	22.040	22.703	23.438	23.788	18.875	18.700	14.825	15.475
B - System Expansion or Upgrades for Capacity	0.753	1.199	2.045	0.248	0.267	0.124	0.805	1.600	1.700	0.475	0.988	0.268	0.368	0.380	0.630	0.530	1.180
C - System Expansion or Upgrades for Reliability and Power Quality	3.895	4.728	6.260	5.842	3.717	4.200	6.139	4.645	9.295	8.130	8.880	8.640	8.065	7.965	2.965	3.265	3.915
D - New Customer Projects and New Revenue	8.525	3.993	3.469	4.333	4.242	3.252	3.504	4.257	4.257	4.257	4.257	4.257	4.257	4.257	4.257	4.257	4.257
E - Grid Modernization and Pilot Projects	0.091	0.278	0.010	0.005	0.152	0.237	0.815	1.050	3.650	4.400	4.900	4.900	4.900	4.650	2.150	2.150	2.150
F - Projects Related to local (or other) government requirements	0.687	1.277	3.023	2.185	1.938	2.201	2.120	0.950	0.700	0.700	0.700	0.700	0.700	0.975	0.700	0.700	0.700
G - Metering	2.214	4.179	4.404	6.327	7.107	6.255	12.523	1.950	1.950	1.950	1.950	1.950	1.950	1.950	1.950	1.950	1.950
H - Other	0.507	4.225	3.323	1.167	0.207	0.151	3.376	2.680	0.680	0.680	0.880	0.680	0.680	0.680	0.680	0.680	0.680
Total ($ millions)	$ 26.879	$ 29.548	$ 35.661	$ 34.743	$ 27.856	$ 28.000	$ 39.834	$ 38.454	$ 44.167	$ 42.632	$ 45.257	$ 44.832	$ 44.707	$ 39.732	$ 32.032	$ 28.357	$ 30.307

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Demonstrating Innovation

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Current DER Programming and Background

- Demand Response
- Electrification
- Small Scale Solar
- Conservation Improvement Program

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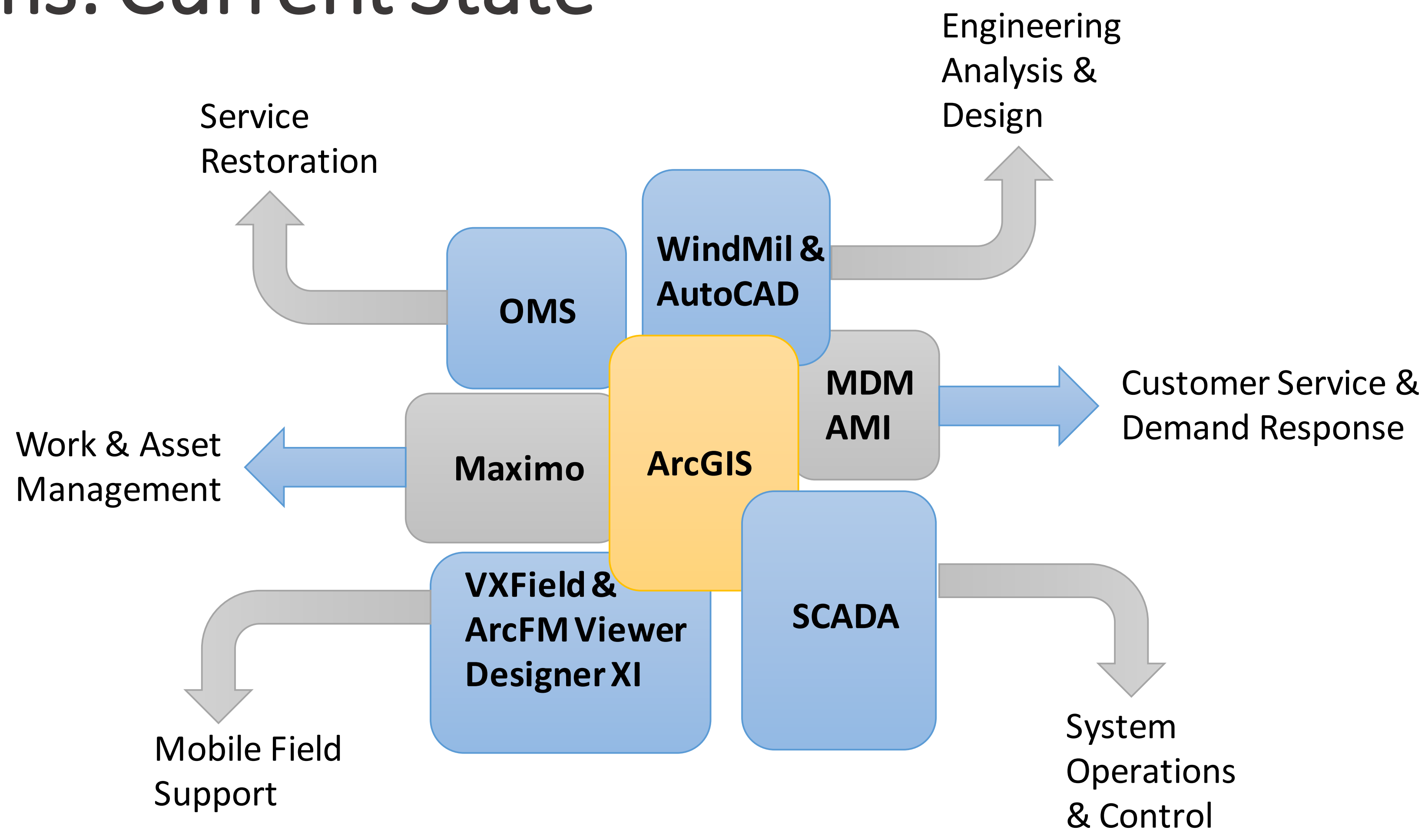
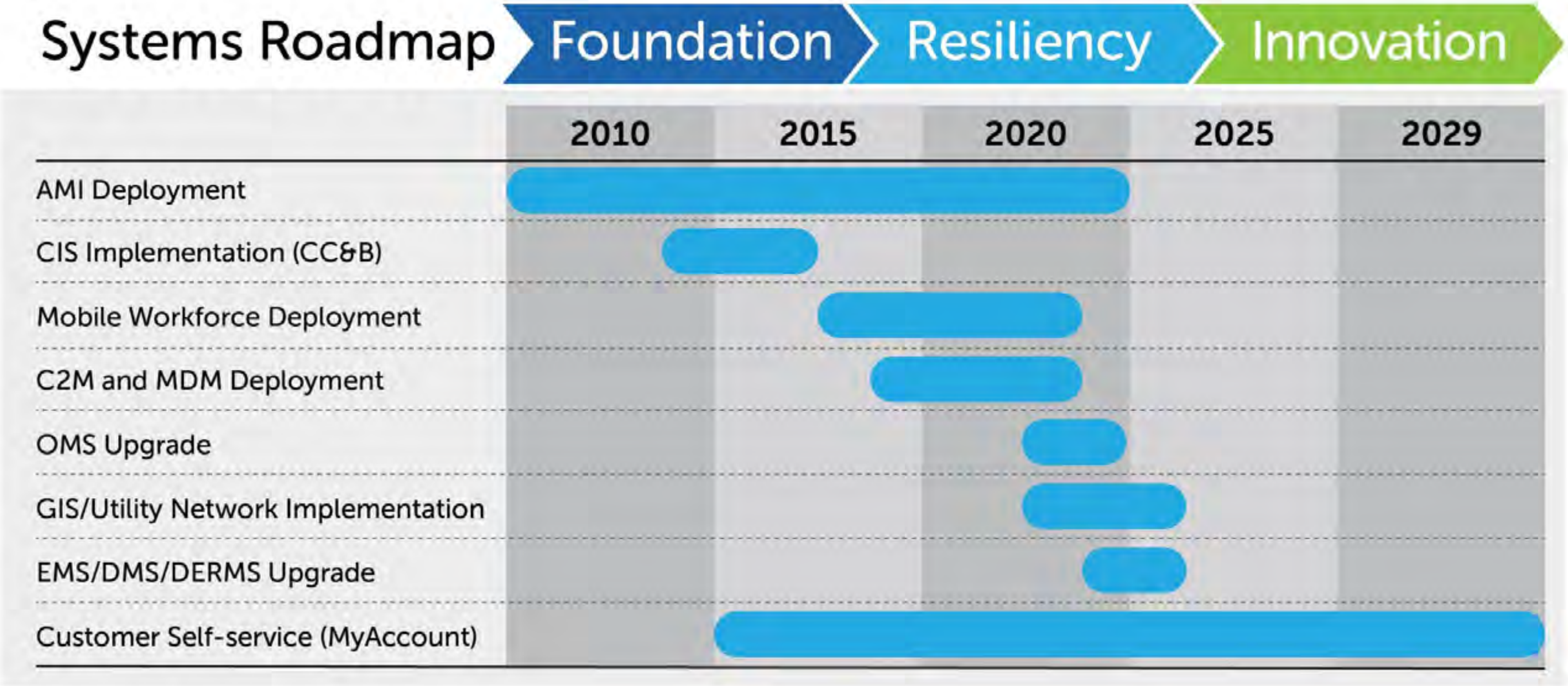
Modernization Investments & Current Projects

- Outage Management System
- Geographical Information System (Utility Network Model)
- Customer to Meter (C2M) Project
- Mobile Applications
  - MAXIMO ANYWHERE
  - DESIGNER XI
  - VxField
  - Inspection Apps (Survey123, Collector)

Systems: Current State



Systems: Future State & Innovation



Current & Past Pilot Programs

- Time of Day/Critical Peak Pricing
- SolarSense Low Income Solar Pilot Program
- Dual Fuel
- EV Service Equipment Donation Pilot
- Street Lighting – LED Replacement Project
- Volt-VAR Optimization *(Future Pilot)*

Non-Wires Alternatives

- Scenario analysis with 3rd party contractor
  - Burnett: backup capability
  - Wrenshall: backup capability, solar + storage dynamics
  - Colbyville: general reliability, vvo/cvr, DER increased penetration
  - Kerrick: backup capability

Planning for a Resilient Future

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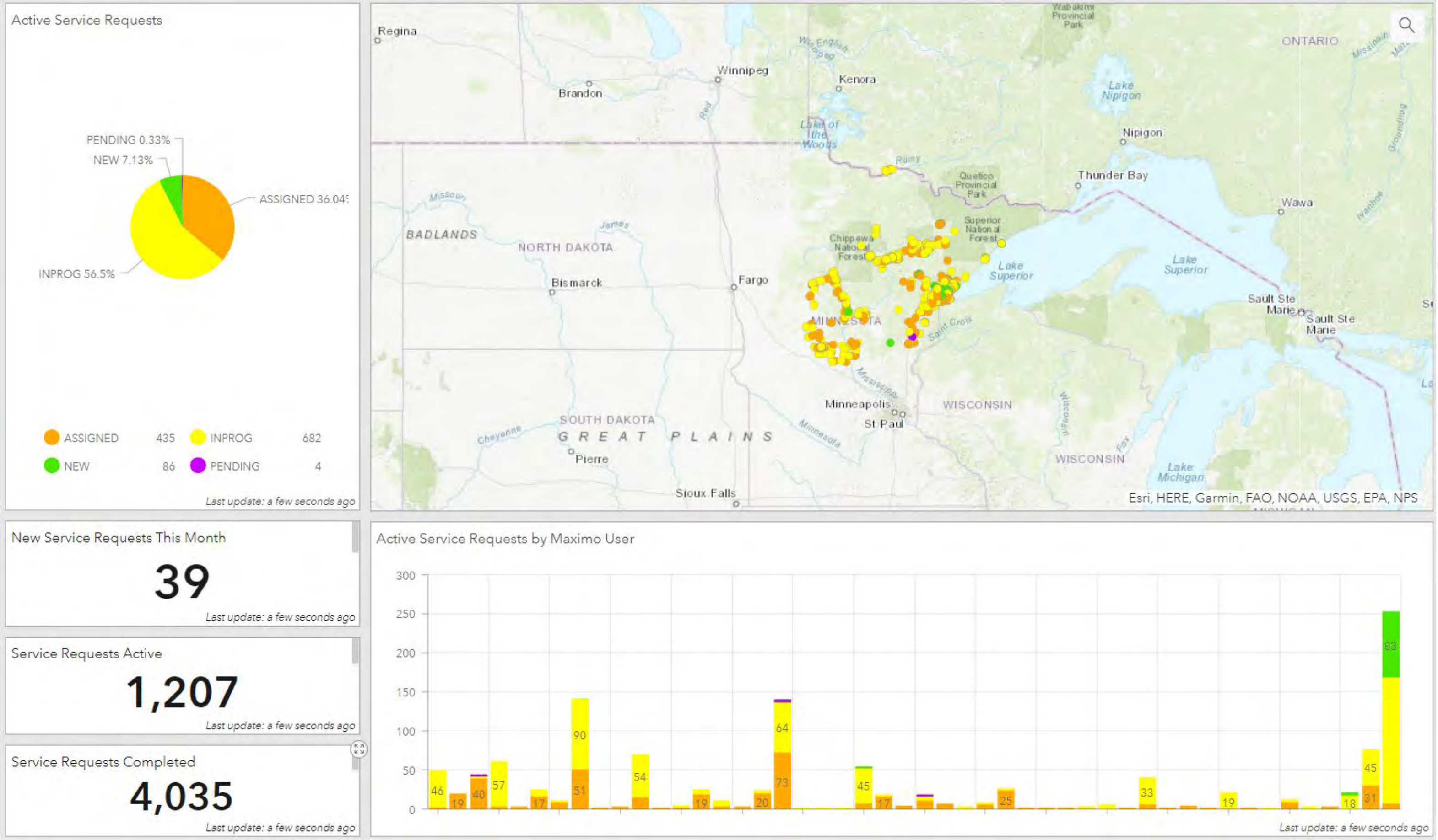
Reliability Target Areas

- Automation
- Mapping
- Groundline
- Vegetation Management
- AMI integration
- Maintenance

Service Request – Trouble Orders



Distribution Resiliency

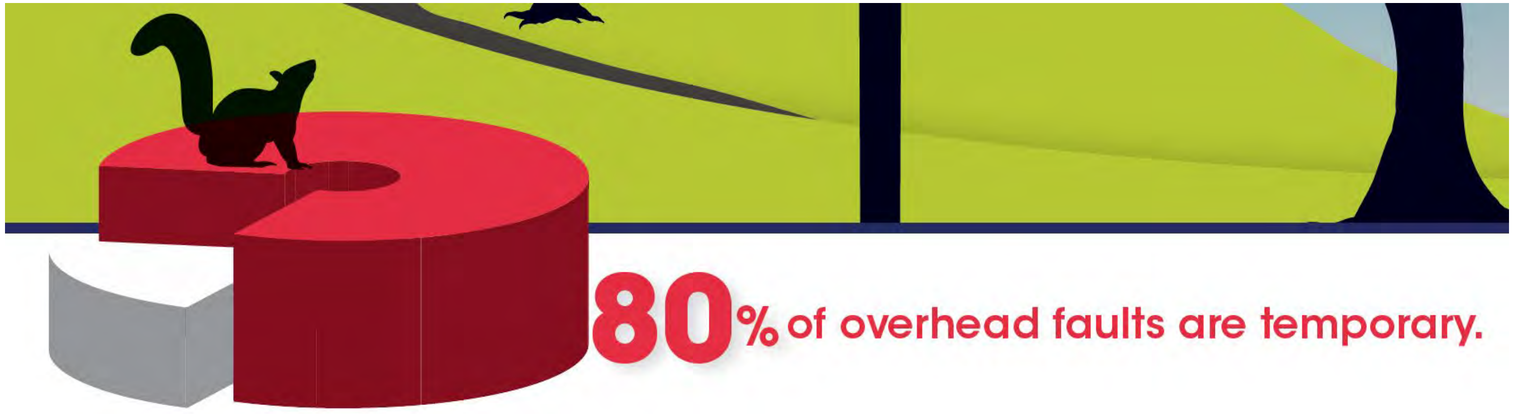
- Automation – FLISR Program initiated in 2010 for Duluth Feeders, expand to other areas
- Automation – Trip Saver Tap Re-closer program started in 2016
- Increased investments in motor-operator remote switching on Distribution Circuits
- Planned upgrades of outlying stepdown substations & transformers
- Strategic Undergrounding started in 2020
- Groundline inspections capitalization program

IntelliRupters

- FLISR technology
- Auto-restore customers
- Continue to rollout IntelliRupters
- Targeting areas for increased reliability

Trip Savers

- Recloser in a cutout body
  - 9 installed in 2017
  - 44 installed in 2018
  - 180 installed in 2019
  - 74 installed in 2020
  - 37 installed, 200 more ordered for 2021
  - Proven technology to clear temporary faults without rolling a truck



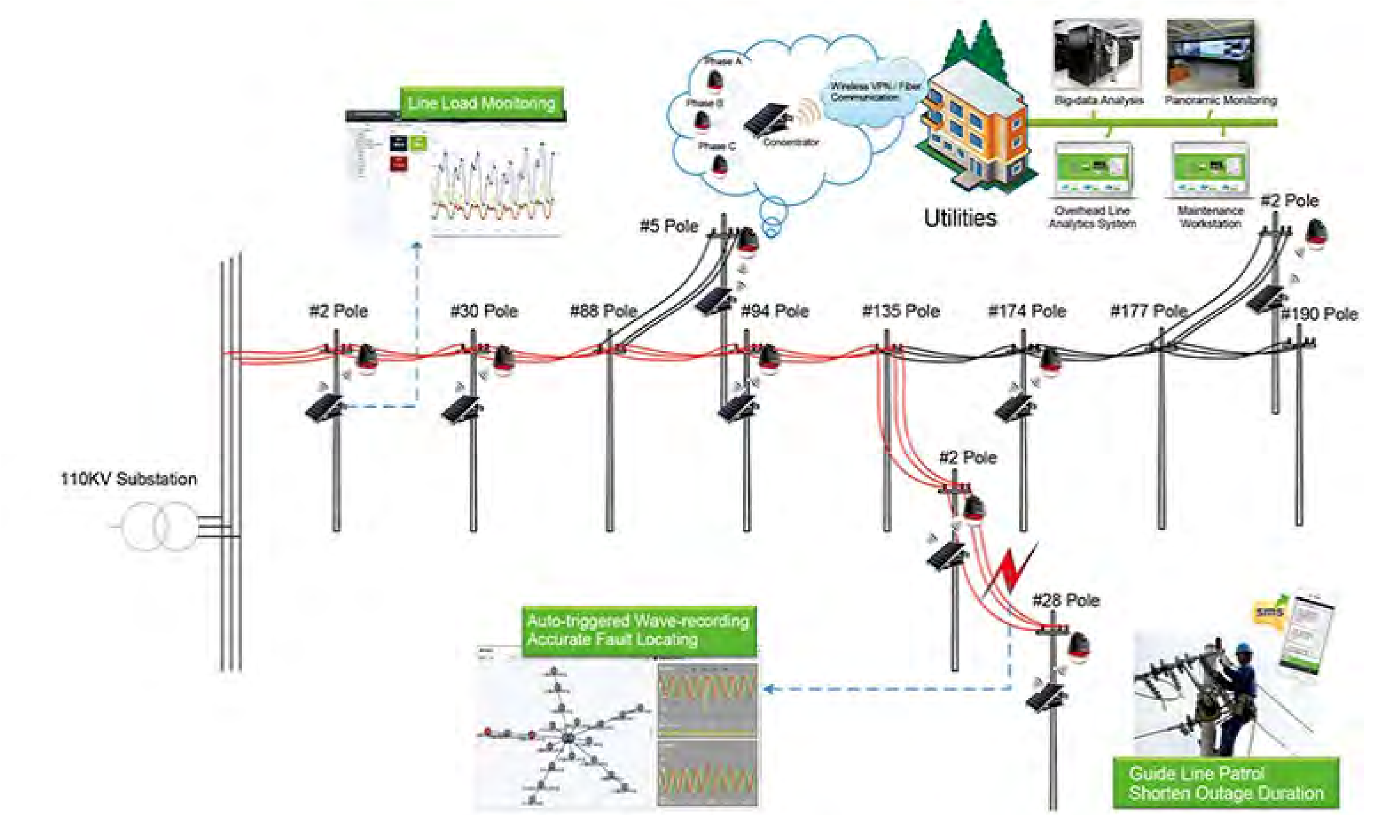
minnesota power
AN ALLETE COMPANY
EnergyForward

Motor Operated Switches

- Investing communications options
- Reduces response time
- Integrate with smart sensors
- 2021 and forward initiative

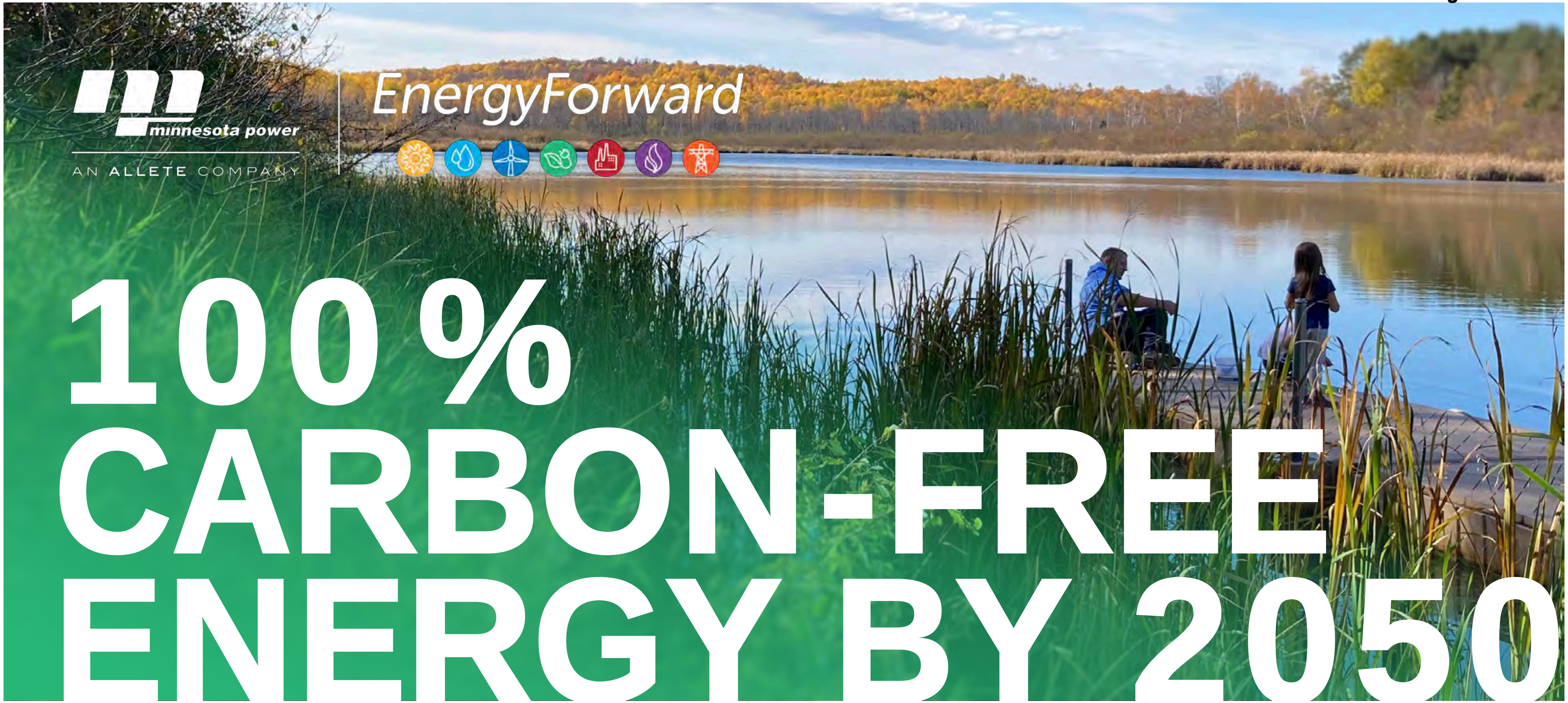
Smart Sensors

- Increased presence across our rural systems



Strategic Undergrounding

- 2020 and forward initiative
- Target heavy tree areas
- Improve reliability
- Reduce O&M costs



Questions & Discussion

Figure 1: System Summary 2020

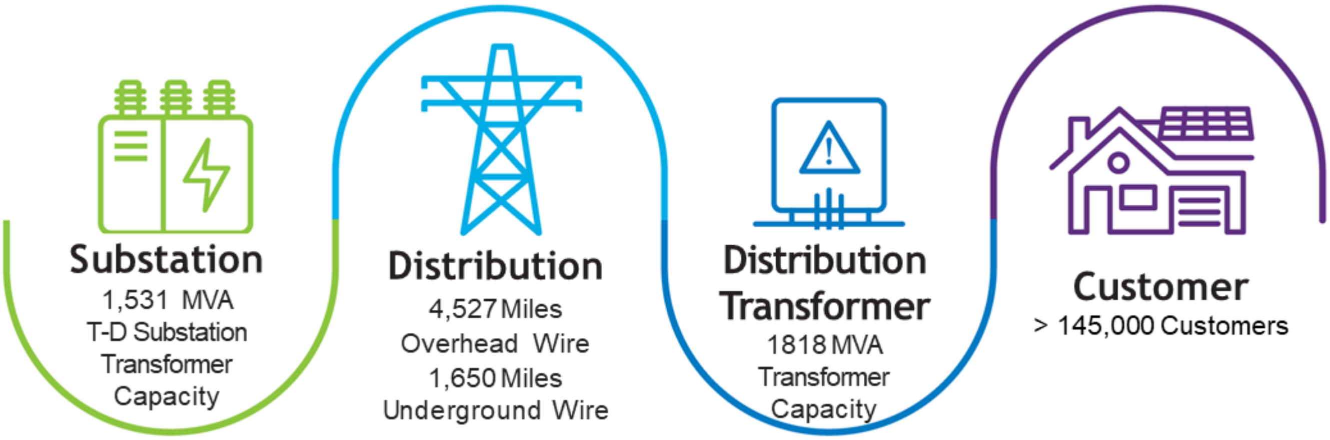


Table 1: Minnesota Power Distributed Energy Resource Status

Minnesota Power Distributed Energy Resource Completed Interconnections in 2021		
DER Technology Type	**Nameplate Rating**	**Interconnections**
Solar	686.49 kW	59
Combined Solar/Storage		
Battery Storage		

Table 2: Minnesota Power Distributed Energy Resource Interconnection Queue

Minnesota Power Distributed Energy Resource Interconnection Queue (as of 8/17/2021)			
Application Completion Date	**Proposed DER Capacity (kW)**	**DER Type**	**Application Status**
10/8/2020	100	Boiler generator	Construction
10/21/2020	7.6	Solar	Construction
10/21/2020	18.96	Solar	Construction
12/3/2020	7.6	Solar	Construction
1/14/2021	3.48	Combined Solar/Storage	Construction
1/14/2021	5	Solar	Construction
1/14/2021	10.15	Solar	Construction
1/20/2021	18	Solar	Construction
1/20/2021	4.89	Solar	Construction
2/13/2021	22.8	Combined Solar/Storage	Construction
2/17/2021	8.99	Solar	Construction
2/17/2021	3.48	Combined Solar/Storage	Construction
2/19/2021	13.6	Solar	Construction
2/24/2021	11.17	Solar	Construction
3/3/2021	7.08	Solar	Construction

(continued next page)

Minnesota Power Distributed Energy Resource Interconnection Queue (as of 8/17/2021)			
Application Completion Date	Proposed DER Capacity (kW)	DER Type	Application Status
3/4/2021	13.96	Solar	Construction
3/4/2021	15	Solar	Construction
3/4/2021	5.31	Solar	Construction
3/4/2021	4.72	Solar	Construction
3/5/2021	2.65	Solar	Construction
3/5/2021	5.31	Solar	Construction
3/8/2021	6.8	Combined Solar/Storage	Construction
3/8/2021	5.31	Solar	Construction
3/11/2021	9.57	Solar	Construction
3/11/2021	7.6	Solar	Construction
3/11/2021	15.2	Solar	Construction
3/11/2021	3.25	Solar	Construction
3/11/2021	6.98	Solar	Construction
3/11/2021	3.54	Solar	Construction
3/12/2021	12	Solar	Construction
3/12/2021	14	Solar	Construction
3/18/2021	14	Solar	Construction
3/18/2021	5.6	Solar	Construction
3/18/2021	14.4	Solar	Construction
3/22/2021	5.6	Solar	Construction
4/1/2021	4.93	Combined Solar/Storage	Construction
4/6/2021	35.2	Solar	Construction
4/8/2021	7.6	Solar	Construction
4/12/2021	3.54	Solar	Construction
4/20/2021	24	Solar	Construction
5/17/2021	15.36	Solar	Construction
6/10/2021	10	Solar	Construction
6/18/2021	3.48	Solar	Construction
6/30/2021	8.38	Solar	Construction
7/1/2021	18	Solar	Construction
7/7/2021	5.35	Solar	Construction
7/9/2021	3.49	Solar	Construction
7/15/2021	14	Solar	Construction
7/16/2021	9.07	Solar	Construction
7/16/2021	9.57	Solar	Construction
7/26/2021	9	Solar	Construction
8/2/2021	7.51	Solar	Construction
4/1/2021	10	Battery Storage	Construction
4/17/2021	10	Battery Storage	Construction
6/17/2021	3.8	Solar	Initial Review
6/26/2021	4.13	Solar	Initial Review
3/11/2021	10.38	Solar	Inspection
4/1/2021	37.5	Solar	Inspection

Minnesota Power

2021 Distribution Loss Study

Study Report

Distribution Planning
September 2021

Revision History

Date	Rev	Description
08/19/2021	0.0	Draft Study Scope
09/10/2021	1.0	Final Study Report

Contributors

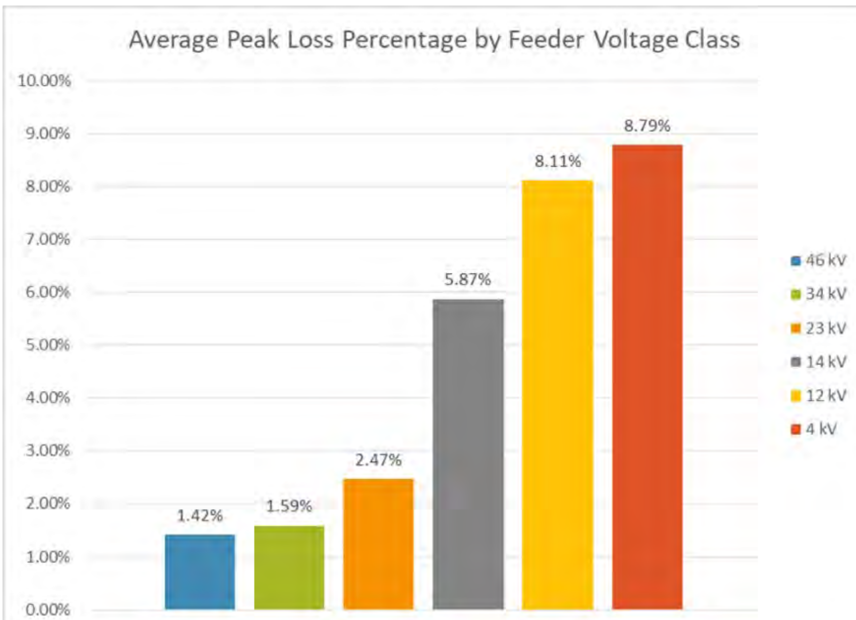
This study report borrows from the 2016 Distribution Loss Study while providing an updated methodology. The report was developed by the Transmission & Distribution Planning Department, with significant contributions from Nick Boldt, Garett Henriksen, and Christian Winter.

Table of Contents

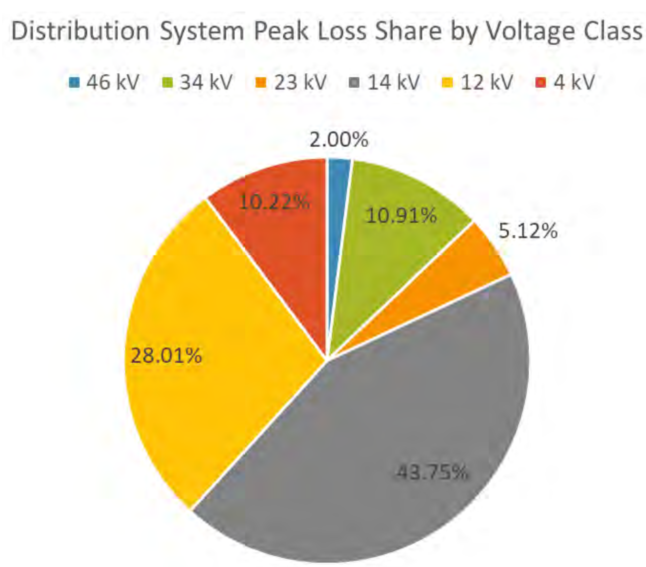
Executive Summary

Peak and energy loss percentages were calculated for Minnesota Power's distribution system and delineated by voltage class. The study results include losses from the distribution substation bus to the customer meter. This loss study replaces the previous (2016) loss study, and also applies and updated and more direct methodology based on GIS data, power flower modeling, and historical data.

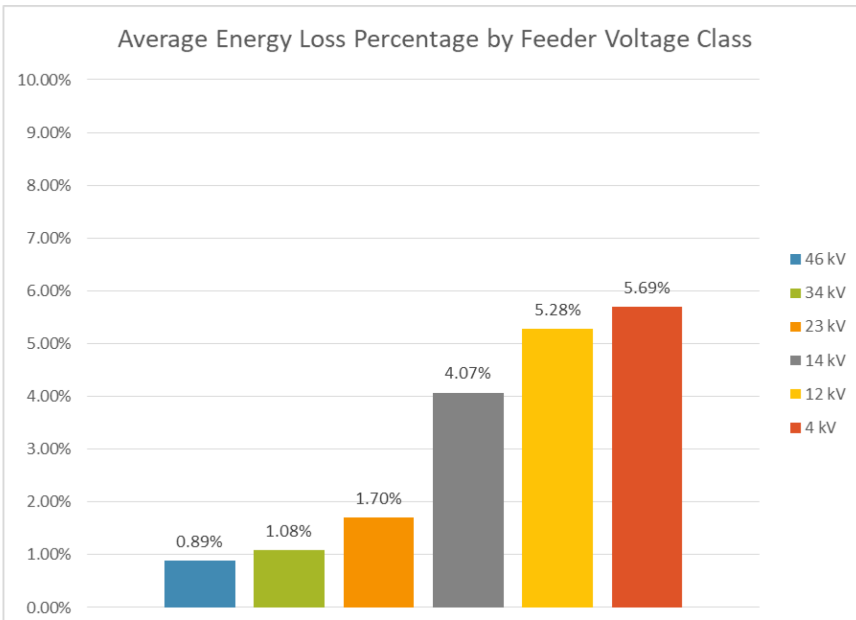
Peak losses are the instantaneous power system losses at the time of greatest distribution system demand. Hourly distribution system loading data from 2020 was evaluated to identify coincident peak distribution system demand. Power system models were evaluated to determine average peak loss percentages by voltage class, as shown the figure below. The average peak loss percentages were then applied to the historical peak-hour demand to estimate total distribution system peak losses, the contribution of each voltage class to system peak losses, and the aggregate Minnesota Power distribution system peak loss percentage. All of these values are provided in the table and chart below. **The peak loss percentage for Minnesota Power's distribution system is 5.75 percent.**



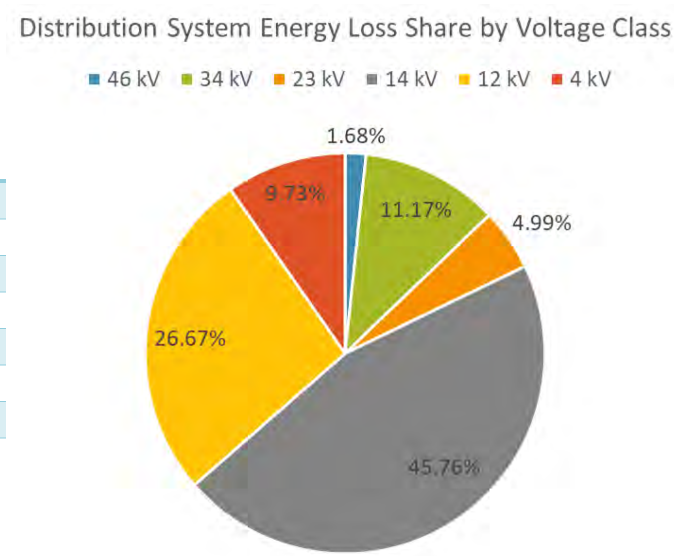
Voltage Class	Estimated Peak Losses	Percentage of Peak Load
4 kV	3.37 MW	0.59 %
12 kV	9.24 MW	1.61 %
14 kV	14.43 MW	2.51 %
23 kV	1.69 MW	0.29 %
34 kV	3.60 MW	0.63 %
46 kV	0.66 MW	0.12 %
TOTAL	**33.00 MW**	**5.75 %**



Energy losses are power system losses accumulated over time, in this case annually. Hourly distribution system loading data from 2020 was evaluated to identify total annual energy served from the distribution system. The average peak loss percentages by voltage class originally derived from power flow models were used along with historical loading information to calculate average energy loss percentages by voltage class, which are shown in the figure below. The average energy loss percentages were then applied to the historical annual energy for the distribution system to estimate annual distribution system energy losses, the contribution of each voltage class to annual energy losses, and the aggregate Minnesota Power distribution system annual energy loss percentage. All of these values are provided in the table and chart below. **The energy loss percentage for Minnesota Power's distribution system is 3.88 percent**



Voltage Class	Estimated Energy Losses	Percentage of Annual Energy
4 kV	12,588 MWh	0.38 %
12 kV	34,492 MWh	1.04 %
14 kV	59,173 MWh	1.78 %
23 kV	6,457 MWh	0.19 %
34 kV	14,439 MWh	0.43 %
46 kV	2,173 MWh	0.07 %
TOTAL	**129,322 MWh**	**3.88 %**



Section 1: Background

Losses are a measure of the energy flow across the system that is converted into heat due to impedance within the elements of the power system. It is necessary for utilities to provide enough generation to serve their respective system demands (plus reserves), taking into account the loss of energy before it can be usefully consumed. Unlike the networked transmission system, the distribution system is normally operated in a radial, source-to-load configuration. As a result of the radial configuration of the distribution system, the power flow on a typical radial distribution feeder corresponds directly to the load that is served by the feeder. This makes it possible to determine the losses specifically attributable to each particular feeder and its connected load. The purpose of this study report is to calculate the losses for Minnesota Power's distribution system based on evaluation of a representative subset of particular distribution feeders from the substation source to the customer meter.

Section 2: Model Development

Loss evaluation was completed in MilSoft WindMil software package using GIS-based feeder models. Historical evaluated load data was utilized as available from SCADA or line sensors to set peak load levels in the models. The loss study used only WindMil models that had previously been developed for other distribution planning studies. No new WindMil models were developed for the loss study.

Section 3: Study Methodology

The loss study utilized historical data and GIS-based feeder models to calculate the losses on a representative subset of Minnesota Power distribution feeders. The study pertains only to Minnesota Power distribution feeders. Losses on distribution systems owned by external entities are not included. The results of loss analysis for the subset of feeders included in the study were used to estimate peak and energy loss percentages by voltage class for Minnesota Power's entire distribution system. The study methodology is described in detail below. A comparison of the assumptions applied in the previous (2016) loss study and the current (2021) loss study is provided in Appendix A: Comparison of 2016 & 2021 Loss Study Assumptions.

3.1 Historical Data Analysis

For each of the feeders in the study, 2020 historical data was evaluated to identify the feeder's annual peak demand when operating in its normal configuration, as well as average demand and annual energy consumption. Where available, SCADA-based historical data was utilized. Where feeders or stepdowns did not have SCADA, line sensor or billing load data was utilized to estimate the peak demand on the feeder. Where feeders serve both Minnesota Power and non-Minnesota Power loads, the impact of the non-Minnesota Power load on Minnesota Power distribution system losses is included in the analysis.

3.2 WindMil Model Simulation

The peak demand data was incorporated into the previously-built WindMil model. The WindMil model includes all data pertaining to the configuration of the feeder, including but not limited to line length, phasing and branch orientation, conductor and impedance assumptions, stepdown transformers and other connected devices, and how customer delivery points are dispersed along the feeder. The majority of this data is imported to WindMil from Minnesota Power's GIS database. Utilizing the WindMil model, the loss calculation was completed in one of three ways, depending on the configuration of the feeder:

A. The following process was applied to calculate feeder peak losses for feeders consisting entirely of a single voltage class ("simple" feeders):
    a. Set source voltage to 1.0 per unit (nominal), turn off all cap banks, and leave all voltage regulators in service and regulating
    b. Allocate historical feeder peak load, including real and reactive power, to all consumers on the feeder with ratios based on historical billing load data
    c. Record total feeder losses reported by WindMil load allocation tool
B. The following process was applied to calculate feeder peak losses for the higher-voltage feeder in a feeder system consisting of multiple voltage classes ("parent" feeders):
    a. Begin with a model of the entire multi-voltage feeder system, including the parent feeder, all stepdown transformers, and all stepdown feeders
    b. Set source voltage to 1.0 per unit (nominal), turn off all cap banks, and leave all voltage regulators in service and regulating
    c. Allocate historical feeder peak load, including real and reactive power, to all consumers on parent and stepdown feeders with ratios based on historical billing load data
    d. For each stepdown transformer, add an equivalent consumer load at the high side of the transformer equal to the real and reactive power flow through the transformer, then disconnect the stepdown transformer and stepdown feeders
    e. Run WindMil voltage drop function and record feeder losses for parent feeder only, including both "kW losses" (conductor losses) and "no load losses" (transformer losses)
C. The following process was applied to calculate feeder peak losses for the lower-voltage feeder in a feeder system consisting of multiple voltage classes ("stepdown" feeders) after previously completing the steps in Part B:
    a. Place an equivalent source at the high side of the stepdown transformer and reconnect stepdown transformer and feeder to new equivalent source (keeping it disconnected from the parent feeder)
    b. Allocate historical stepdown feeder load, if different from previous load allocation, to all consumers on stepdown feeder with ratios based on historical billing load data
    c. Record stepdown feeder and transformer losses reported by WindMil load allocation tool

3.3 Calculation of Peak and Energy Loss Percentages

The processes described in Sections 3.1 and 3.2 provide the modeled peak losses for each feeder in the study. The feeder peak loss percentage may then be calculated according to the following formula:

(1) $$Feeder\ Peak\ Loss\ Percentage = Feeder\ Losses\ at\ Peak\ Demand / Feeder\ Peak\ Demand$$

Feeder energy losses were also calculated. The peak loss percentage represents only the instantaneous losses on the feeder at the moment of peak load. In reality, demand for electric power is not constant and power flow on a given distribution feeder varies over time, increasing as demand increases and decreasing as demand decreases. Since feeder losses are proportional to the current flowing on the line, the losses on the feeder will also vary over time. Feeder energy losses represent the average annual energy losses accumulated on the feeder as the loading varies over time. The annual energy consumption for a feeder can be calculated by adding demand (kW) from all hours in a given year to get total energy in kilowatt-hours (kWh). There is no precise way to calculate average annual energy losses, but one common method[1] uses the peak and average feeder demand and the losses at peak demand to estimate average annual energy losses according to the following formulas:

[1] Gönen, Turan. *Electric Power Distribution System Engineering.* McGraw Hill, 1986. 55, 58-59

(2) $Load\ Factor = Average\ Demand / Peak\ Demand$

(3) $Loss\ Factor = (0.3 \times Load\ Factor) + (0.7 \times Load\ Factor^2)$

(4) $Annual\ Energy\ Losses\ (MWh) = (Loss\ Factor \times Losses\ at\ Peak\ Demand) \times Hours$

The average demand and peak demand values in equation (2) are derived from historical data as described in Section 3.1. The losses at peak demand in equation (4) are derived from the WindMil model as described in Section 3.2. Normally the "Hours" in equation (4) would be 8,760, which is the total number of hours in a typical year. However, since this study used historical data from 2020, which was a leap year, the total number of hours used in equation (4) for this study was 8,784. The feeder energy loss percentage may then be calculated according to the following formula:

(5) $Energy\ Loss\ Percentage = Annual\ Energy\ Losses / Annual\ Energy\ Consumption$

3.4 Calculation of System Loss Percentages

System loss percentages were calculated based on the representative set of feeders included in the study. Table 1 at the end of this section lists the feeders that were included in the study along with the feeder voltage class and feeder type (simple, parent, or stepdown). For each of the voltage classes, the contribution of that voltage class to total distribution system losses and the total distribution system loss percentage was determined for peak losses and for energy losses, as described below.

<u>System Peak Loss Percentages</u>

a) For each voltage class, calculate the peak loss percentage for that voltage class based on the average of peak loss percentages for all feeders of that voltage class included in the study
b) From historical data, calculate the coincident peak load served by Minnesota Power's distribution system at the transmission-to-distribution substation interface for calendar year 2020, excluding an distribution system load that is not served by a Minnesota Power distribution system feeder (e.g., it is served directly from the substation bus)
c) For each substation, determine the share of the coincident peak load associated with each voltage class present at the substation
    a. For substations with multi-voltage (parent/stepdown) feeder systems, develop an allocation factor for the substation to split the total substation load between the voltage classes that are present on the feeders. In general, the parent voltage class will carry the full load of the feeder while the stepdown voltage classes will only carry what is attributable to the stepdowns based on historical data or engineering estimates
d) For each substation, calculate peak distribution system losses by voltage class according to the following formula:

$$Peak\ Loss_{VC} = Peak\ Load_{VC} \times Peak\ Loss\ Percentage_{VC}$$

Where $Peak\ Load_{VC}$ is the share of that voltage class in the coincident peak load by substation from (c) and $Peak\ Loss\ Percentage_{VC}$ is the voltage class peak loss percentage from (a)
e) Add up the peak losses calculated for each substation in (d) to obtain system peak losses by voltage class. Add up the peak losses for all voltage classes to obtain total system peak losses.
f) The contribution of each voltage class to total system peak losses may then be represented both in terms of physical units (kW or MW) as well as a percentage of the total system peak losses

<u>Energy Loss Percentages</u>

a) For each voltage class, calculate the energy loss percentage for that voltage class based on the average of energy loss percentages for all feeders of that voltage class included in the study
b) From historical data, calculate the total annual energy served by Minnesota Power's distribution system at the transmission-to-distribution substation interface for calendar year 2020, excluding

an distribution system load that is not served by a Minnesota Power distribution system feeder (e.g., it is served directly from the substation bus)

c) For each substation, determine the share of the total annual energy associated with each voltage class present at the substation
    a. For substations with multi-voltage (parent/stepdown) feeder systems, develop an allocation factor for the substation to split the total annual energy between the voltage classes that are present on the feeders. In general, the parent voltage class will carry the full load of the feeder while the stepdown voltage classes will only carry what is attributable to the stepdowns based on historical data or engineering estimates
d) For each substation, calculate distribution system energy losses by voltage class according to the following formula:

$$Energy\ Loss_{VC} = Annual\ Energy_{VC} \times Energy\ Loss\ Percentage_{VC}$$

Where *Annual Energy*$_{VC}$ is the share of that voltage class in the total annual energy by substation from (c) and *Energy Loss Percentage*$_{VC}$ is the voltage class energy loss percentage from (a)
e) Add up the energy losses calculated for each substation in (d) to obtain system energy losses by voltage class. Add up the energy losses for all voltage classes to obtain total annual energy losses.
f) The contribution of each voltage class to total annual energy losses may then be represented both in terms of physical units (kWh or MWh) as well as a percentage of the total annual energy losses

Table 1: Feeders Included in the Study

Feeder	kV	Area	Type
23 LINE	46	Central	Parent
ASK-6521	12	Central	Stepdown
CLQ-406	14	Central	Simple
CLQ-409	14	Central	Parent
CLQ-410	14	Central	Simple
COL-240	14	Central	Simple
COL-241	14	Central	Simple
COL-242	14	Central	Simple
COL-244	14	Central	Simple
COL-245	14	Central	Simple
CQB-6301	12	Central	Stepdown
FOR-262	14	Central	Stepdown
FOR-262	14	Central	Stepdown
FRR-275	14	Central	Simple
GRY-200	14	Central	Simple
GRY-201	14	Central	Simple
KER-6501	12	Central	Stepdown
LSP-208	34	Central	Parent
NIN-246	14	Central	Stepdown
NIN-248	14	Central	Stepdown
RGV-253	14	Central	Simple
SLA-203	34	Central	Parent
SND-217	14	Central	Stepdown
SND-218	14	Central	Stepdown
TFW-243	14	Central	Stepdown
WRN-411	14	Central	Parent
WRR-6321	12	Central	Stepdown
31 LINE	46	Northern	Parent
32 LINE	46	Northern	Parent
33 LINE	46	Northern	Parent
HYN-1	4	Northern	Stepdown
HYN-2	4	Northern	Stepdown
BAL-1	12	Northern	Stepdown
BAL-2	12	Northern	Stepdown
CHL-1	4	Northern	Stepdown
CHL-2	4	Northern	Stepdown
CHL-3	4	Northern	Stepdown
AUR-313	23	Northern	Parent
HIB-308	23	Northern	Parent
HIB-310	23	Northern	Parent
HIB-312	23	Northern	Simple
HIB-315	23	Northern	Parent

Feeder	kV	Area	Type
INF-1	12	Northern	Simple
INF-2	12	Northern	Simple
INF-3	12	Northern	Simple
INF-4	12	Northern	Simple
KLY-1	4	Northern	Stepdown
MTU-330	23	Northern	Parent
STZ-1	4	Northern	Stepdown
STZ-2	4	Northern	Stepdown
SVE-1	4	Northern	Stepdown
SVW-2	4	Northern	Stepdown
SWB-1	4	Northern	Stepdown
VRG-302	23	Northern	Simple
BAX-534	34	Western	Parent
BBR-1	12	Western	Stepdown
BRW-1	12	Western	Stepdown
BRW-2	12	Western	Stepdown
CLR-1	12	Western	Stepdown
CLR-2	12	Western	Stepdown
EGV-517	34	Western	Parent
FLN-1	12	Western	Stepdown
FLN-2	12	Western	Stepdown
GGR-1	12	Western	Stepdown
HPS-1	12	Western	Stepdown
LCH-1	12	Western	Stepdown
LGP-1	12	Western	Stepdown
LLK-1	12	Western	Stepdown
LNL-1	12	Western	Stepdown
LPD-2	4	Western	Stepdown
LPN-1	12	Western	Stepdown
LPR-501	34	Western	Parent
LPR-527	34	Western	Parent
LPR-535	34	Western	Parent
PIL-1	12	Western	Stepdown
PNB-1	12	Western	Stepdown
PNB-2	12	Western	Stepdown
PPL-514	34	Western	Parent
RVT-532	34	Western	Parent
RVD-1	12	Western	Stepdown
SWN-1	12	Western	Stepdown

Section 4: Loss Analysis Results

4.1 Historical Data Analysis

For each of the feeders listed in Table 1, the values derived from historical data analysis are provided in the table in Appendix B: Feeder Loss Calculations. As shown in the appendix and described in Section 3, the feeder peak, average, and annual energy data were used to calculate loss percentages by feeder.

4.2 WindMil Model Simulation

For each of the feeders listed in Table 1, the losses derived from the WindMil model analysis are provided in the table in Appendix B: Feeder Loss Calculations. As shown in the appendix and described in Section 3, the modeled feeder losses were used along with historical data to calculate loss percentages by feeder.

4.3 Calculation of Peak and Energy Loss Percentages

For each of the feeders listed in Table 1, the individual feeder peak and energy loss percentages calculated from the combination of historical data and WindMil model analysis are also provided in the table in Appendix B: Feeder Loss Calculations. Individual feeder loss percentages vary from 0.1 percent to over 16 percent and, as expected, are inversely proportional to voltage (e.g. lower for higher voltage classes and higher for lower voltage classes). Energy loss percentages are generally lower than peak loss percentages, which is also an expected outcome since the feeders spend most of the year well below the peak condition and losses vary by the square of the current, meaning that the impacts of lower average loading are amplified exponentially in the energy losses. As discussed below and described in Section 3, the individual feeder loss percentages were used to estimate systemwide loss percentages by voltage class.

Table 2 below shows an example of feeder loss analysis for COL-240, a 14 kV feeder originating at the Colbyville Substation in East Duluth, using historical data and WindMil model values to calculate individual peak and energy loss percentages for the feeder.

Line	Description	Value	Units	Source
0	Feeder	COL-240		
1	Feeder Peak Date	12/24/2020 17:00		Historical Data
2	Peak Loading @ Source	7.53	MW	Historical Data
3	Peak Loading @ Source	7.54	MW	WindMil Model following Load Allocation
4	Peak Losses	495.90	kW	WindMil Model following Load Allocation
5	Peak Loss Percentage	6.58%		[Line 4] / [Line 3]
6	Avg Loading @ Source	4.17	MW	Historical Data
7	Load Factor	55.31%		[Line 6] / [Line 2]
8	Loss Factor	38.01%		(0.3 x [Line 7]) + (0.7 x [Line 7]^2)
9	Average Losses	188.48	kW	[Line 8] x [Line 4]
10	Annual Energy Losses	1,656	MWh	[Line 9] / 1000 x 8784 (leap year)
11	Annual Energy	36,605	MWh	Historical Data
12	Energy Loss Percentage	4.52%		[Line 10] / [Line 11]

Table 2: Colbyville 240 Feeder Loss Analysis Table

4.4 Calculation of System Loss Percentages

As described in Section 3.4, the peak and energy loss percentages for each voltage class were calculated based on the average of all individual feeder peak and energy loss percentages for that voltage class. The calculated individual feeder peak and energy loss percentages are shown in Table 3 and illustrated in Figure 1 and Figure 2 below.

Voltage Class	Peak Loss Percentage	Energy Loss Percentage
4 kV	8.79 %	5.69 %
12 kV	8.11 %	5.28 %
14 kV	5.87 %	4.07 %
23 kV	2.47 %	1.70 %
34 kV	1.59 %	1.08 %
46 kV	1.42 %	0.89 %

Table 3: Peak & Energy Loss Percentages by Voltage Class

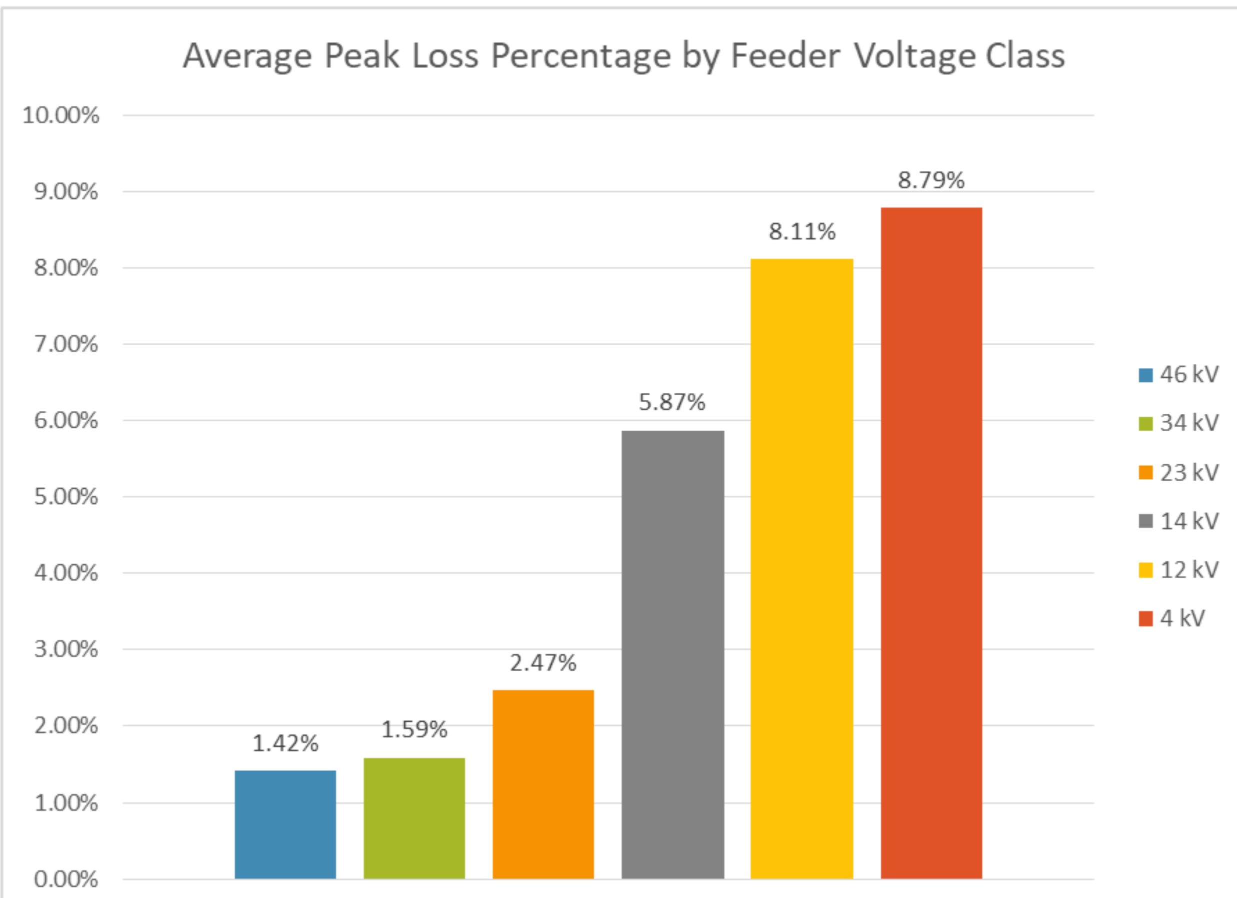


Figure 1: Average Peak Loss Percentage by Feeder Voltage Class

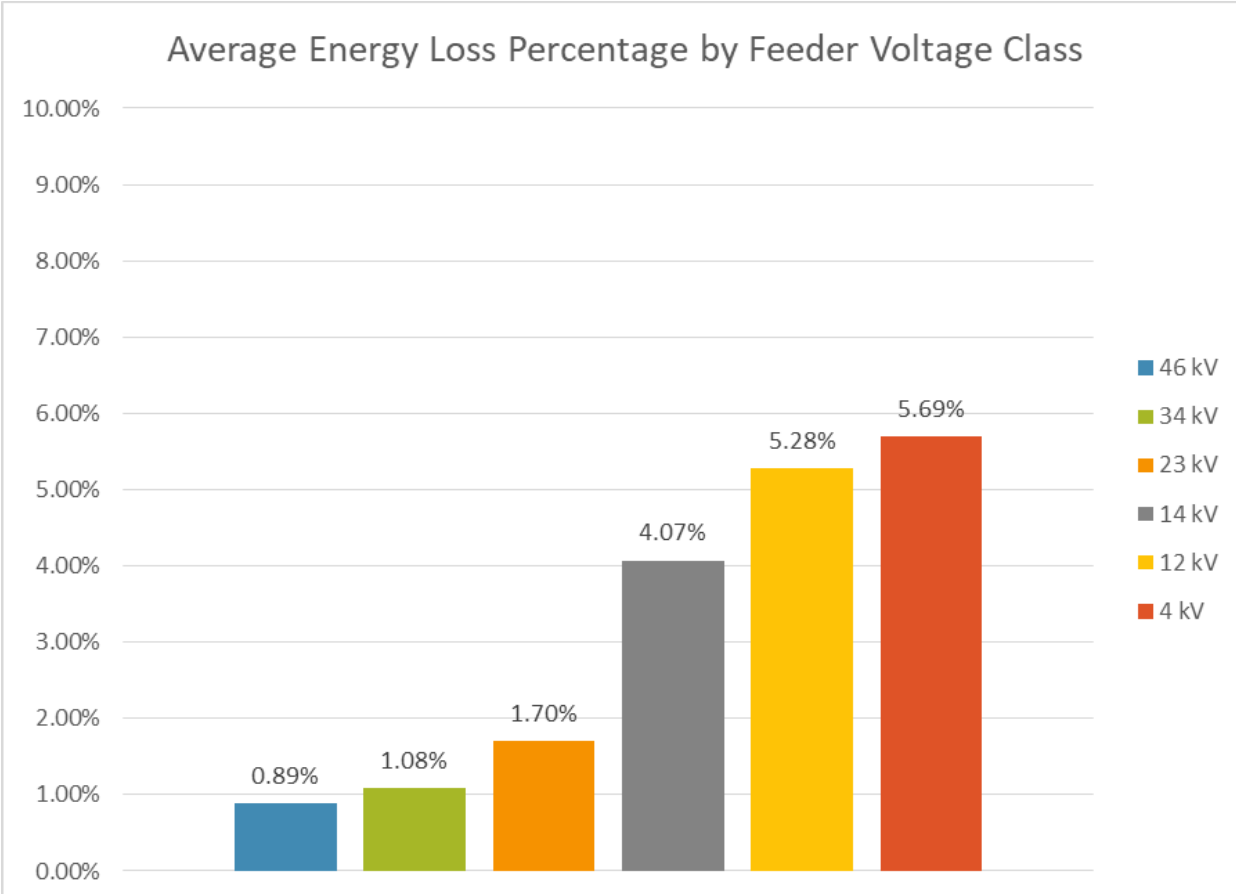


Figure 2: Average Energy Loss Percentage by Feeder Voltage Class

This methodology assumes that the sample set of feeders for each voltage class is sufficiently representative of the entire voltage class and that the inclusion of more feeders would not significantly change the average loss percentages. Within the initial results, significant outliers were re-evaluated to ensure modeling errors were not driving high losses on the feeders. Where obviously incorrect equipment accounting for a significant portion of the feeder losses could be identified from comparing the model and the GIS database, the equipment was corrected and the initial loss study results were updated.

FOR-262 is an example of where this process greatly improved the accuracy and confidence level of the loss study results. Initially, total losses on FOR-262 were 366.1 kW (14.08%) from the WindMil model. Since this was more than double the average loss percentage of other 14 kV feeders included in the study, further investigation was warranted. Upon inspection, it was found that four overloaded elements accounted for over 80 percent of total losses on the feeder. The four elements are shown in Table 4.

Element Name	Thru Amps	Thru kW	Capacity Percent	KW Loss
TX147635	20.251 A	457.962 kW	483.93%	51.791 kW
TX31737	26.817 A	849.780 kW	298.02%	57.082 kW
SecUG242387	582.292 A	406.042 kW	766.17%	90.745 kW
SecUG244627	1058.757 A	790.683 kW	471.81%	101.284 kW
			TOTAL	**300.902 kW**

Table 4: FOR-262 High-Loss Equipment Model Corrections

The first two elements are transformers for which the transformer size was incorrectly imported into WindMil from the GIS, most likely due to a data entry irregularity in the GIS. Review of existing GIS data showed that TX147635 has a nameplate rating of 750 kVA and TX31737 has a nameplate rating of 1000 kVA, both of which are sufficient to mitigate the overloads flagged in the model. The other two elements are conductor segments for which no conductor data was populated in the GIS. When unknown conductors are present in the underlying GIS data, they are conservatively assigned a small conductor size in the WindMil model. In this case, the small conductor size did not drive any performance issues with the overall feeder, but did significantly increase losses for the two conductor segments, as shown in Table 4. Based on inspection of adjacent conductor segments, both of these elements were updated to 500 CU, which has a capacity of 470 Amps. While this does still leave the conductor elements overloaded, it appears consistent with field data and the magnitude of the modeled overloads and associated conductor losses was greatly reduced. After modifying these four elements, total losses on FOR-262 were reduced to 93.8 kW (3.61%).

The results of making similar updates to other high-loss feeders are shown in a table in Appendix B: Feeder Loss Calculations.

After the data validation process described above, variations in loss percentage within each voltage class appear reasonable, leading to a high level of confidence in the modeled losses. Within each voltage class, loss percentages generally center on the average, and outliers on both the high and low end can be explained based on the specific circumstances for the feeders. Examples are discussed below.

Within the 34 kV voltage class, the minimum individual feeder peak loss percentage was 0.14% (LPR-527), the maximum was 2.66% (SLA-203), and the average was 1.59%. Considering LPR-527, which produced the smallest individual peak loss percentage of all 34 kV feeders – and the second-smallest loss percentage of all feeders of any voltage class – we find the following underlying circumstances. First, most of the load on LPR-527 is served from two stepdowns, Gutches Grove (GGR) and Long Prairie Distribution (LPD), which are located just outside the Long Prairie 115/34 kV Substation. The only load flowing past those two stepdowns serves a Great River Energy delivery point (Pillsbury) located toward the end of the feeder near the tie switch. On average, over 70 percent of the total feeder load gets off just outside the Long Prairie Substation. The remaining power flowing on the line to the Great River Energy delivery point flows on mostly 336 ACSR conductor, which is a higher-capacity, lower-impedance conductor for the 34 kV system. The configuration of LRP-527, therefore, helps explain why the loss percentage is lower – there isn't a lot of power flowing on most of the line, and the power that is flowing on the line flows on one of the least lossy distribution conductors on the Minnesota Power system.

On the other hand, the feeder with the highest individual loss percentage in the 34 kV class was SLA-203, where we find the following underlying circumstances. First, all of the load on SLA-203 is located over 5.75 miles away from the Swan Lake Road 115/34 kV Substation. The first delivery point is to the St Luke's Hospital, while subsequent delivery points serve 34/14 kV stepdowns in and near Downtown Duluth. While the feeder is primarily 636 ACSR overhead conductor, the fact that all feeder load must travel at least 50 percent the length of the entire feeder is what drives up the losses.

4.5 Distribution System Loss Analysis

As described in Section 3.4, the calculated loss percentages by voltage class shown in Table 3 were utilized to estimate total Minnesota Power distribution system peak and energy losses and to identify the contribution of each voltage class to the totals. Calculated demand and energy losses are provided in Table 5 & Table 6, while the contribution of each voltage class to the total system losses is provided in Figure 3 and Figure 4. Details of the analysis are discussed below.

Voltage Class	Estimated Peak Losses	Percentage of Peak Load
4 kV	3.37 MW	0.59 %
12 kV	9.24 MW	1.61 %
14 kV	14.43 MW	2.51 %
23 kV	1.69 MW	0.29 %
34 kV	3.60 MW	0.63 %
46 kV	0.66 MW	0.12 %
TOTAL	**33.00 MW**	**5.75 %**

Table 5: Distribution System Peak Losses

Voltage Class	Estimated Energy Losses	Percentage of Annual Energy
4 kV	12,588 MWh	0.38 %
12 kV	34,492 MWh	1.04 %
14 kV	59,173 MWh	1.78 %
23 kV	6,457 MWh	0.19 %
34 kV	14,439 MWh	0.43 %
46 kV	2,173 MWh	0.07 %
TOTAL	**129,322 MWh**	**3.88 %**

Table 6: Distribution System Energy Losses

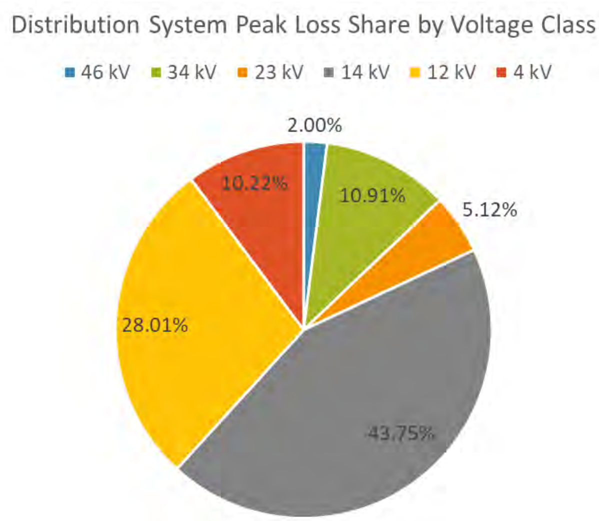


Figure 4: Peak Loss Share by Voltage Class

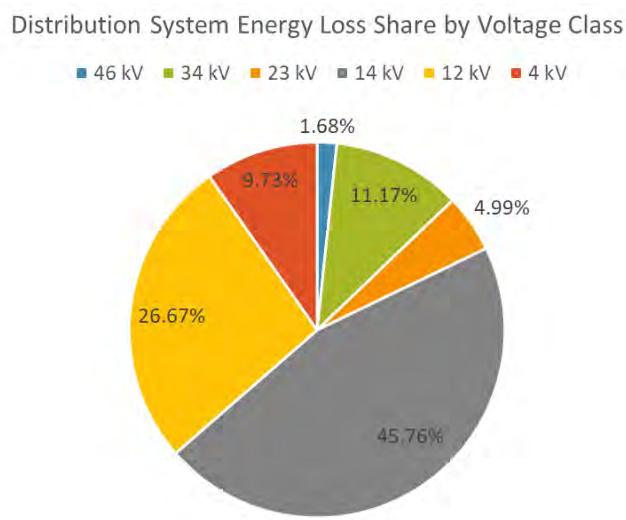


Figure 3: Energy Loss Share by Voltage Class

Identification of Peak Loss Percentage

To determine total peak distribution system losses, historical load data from all Minnesota Power distribution feeders was grouped by substation and then evaluated to find the coincident historical peak hour for Minnesota Power distribution system loading from calendar year 2020. Bus-connected distribution customer loads, such as wholesale municipal customer loads, were excluded from this analysis as those loads do not drive losses on the Minnesota Power distribution system. As shown in Figure 5 below, the peak distribution system load from 2020 that was used for the loss analysis was 574 MW on February 13, 2020 at 8:00 AM.

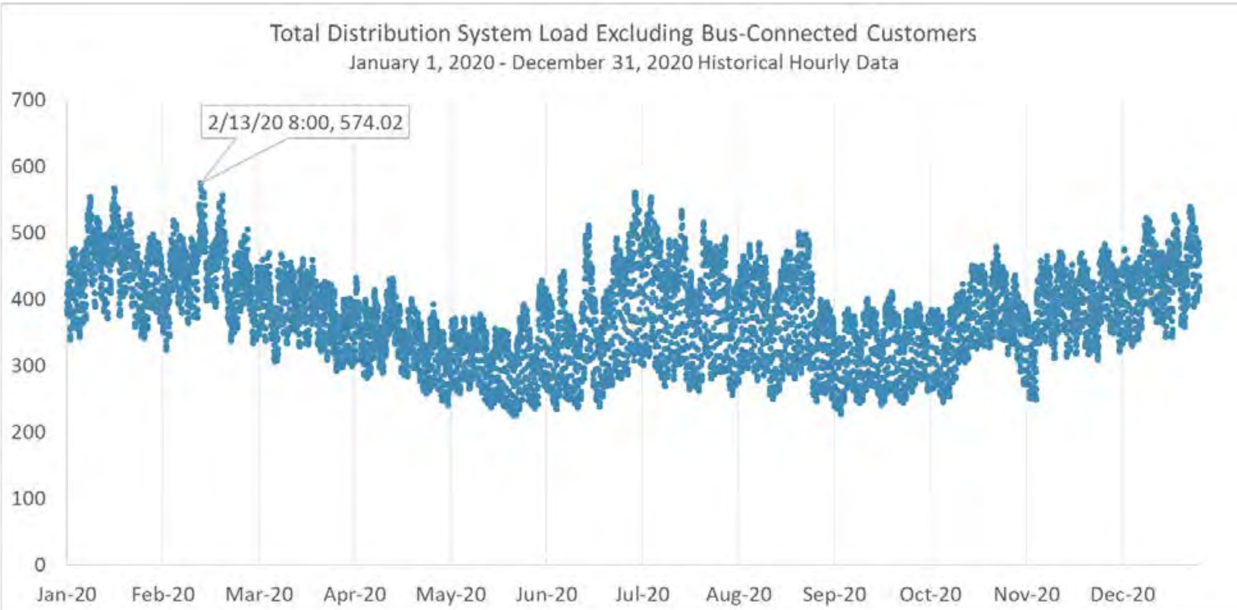


Figure 5: Minnesota Power 2020 Distribution System Coincident Loading

The contribution of each substation to peak-hour loading was determined based on the historical data. For each substation, the contribution of each of the feeder voltage classes associated with the substation was determined based on allocation factors derived from historical data and engineering estimates, as discussed in Section 3.4. The allocation factors were combined with the average peak loss factors from Table 3 to estimate the actual losses incurred on each voltage class at each substation during the 2020 peak load hour. The Akeley Substation is provided as an example in Table 7.

Akeley 34/12/4 kV	Allocation Factors	kV Class Peak Loss Factor	kV Class Peak Load	kV Class Peak Losses
4 kV	14.53 %	8.79 %	2.09 MW	0.18 MW
12 kV	40.11 %	8.11 %	5.78 MW	0.47 MW
14 kV	0.00 %	N/A	N/A	N/A
23 kV	0.00 %	N/A	N/A	N/A
34 kV	100.00 %	1.59 %	14.40 MW	0.23 MW
46 kV	0.00 %	N/A	N/A	N/A
		Total on 2/13/20 0800	**14.40 MW**	**0.88 MW**

Table 7: Akeley Substation Peak Loss Analysis Example

Finally, the results from the individual substations were added up to determine the estimated peak losses by voltage class, the total system peak loss percentage, and the contribution of each voltage class to the total peak losses, as shown in Table 5 and Figure 3 above.

Identification of Energy Loss Percentage

To determine distribution system annual energy losses, hourly historical load data from all Minnesota Power distribution feeders was grouped by substation and then all 8,784 hours were added up to obtain total annual energy for calendar year 2020. Bus-connected distribution customer loads, such as wholesale municipal customer loads, were excluded from this analysis as those loads do not drive losses on the Minnesota Power distribution system. The total annual energy for the Minnesota Power distribution system in 2020 that was used for the loss analysis was 3,330,942 MWh.

The contribution of each substation to annual energy consumption was determined based on the historical data. For each substation, the contribution of each of the feeder voltage classes associated with the substation was determined based on allocation factors derived from historical data and engineering estimates, as discussed in Section 3.4. The allocation factors were combined with the average energy loss factors from Table 3 to estimate the actual energy losses incurred on each voltage class at each substation during 2020. The Akeley Substation is provided as an example in Table 7.

Akeley 34/12/4 kV	Allocation Factors	kV Class Energy Loss Factor	kV Class Energy	kV Class Energy Losses
4 kV	14.53 %	5.69 %	10,716 MWh	610 MWh
12 kV	40.11 %	5.28 %	29,592 MWh	1,562 MWh
14 kV	0.00 %	N/A	N/A	N/A
23 kV	0.00 %	N/A	N/A	N/A
34 kV	100.00 %	1.08 %	73,774 MWh	797 MWh
46 kV	0.00 %	N/A	N/A	N/A
	Total Annual Energy for 2020		**73,774 MWh**	**2,969 MWh**

Table 8: Akeley Substation Peak Loss Analysis Example

Finally, the results from the individual substations were added up to determine the estimated annual energy losses by voltage class, the total system energy loss percentage, and the contribution of each voltage class to the total energy losses, as shown in Table 6 and Figure 4 above.

Appendix A: Comparison of 2016 & 2021 Loss Studies

The table below gives an overview of the differences in methodology and assumptions from the previous 2016 Loss Study to the current 2021 Loss Study. The methodology for the 2021 Loss Study was updated to be more direct and accurate when compared to the 2016 Loss Study.

2016 Loss Study	2021 Loss Study
Did not have readily available software tools integrated with GIS to perform loss calculations	Used previously-built WindMil models populated directly with data from GIS to perform loss calcuations
Evaluated a total of 9 feeders	Evaluated a total of 78 feeders
Includes the impact of other companies, cooperatives, and municipalities only up to the point of primary service point	Includes the impact of external utilities' loading as it flows across Minnesota Power distribution feeders. Bus-connected distribution loads excluded.
Assumed data in GIS was accurate	Assumed data in GIS was accurate
Assumed loads along feeder sections are uniformly distributed and balanced between phases	Load allocation and per-phase loading based on WindMil model and billing load data; feeders may be unbalanced
Feeders are only serving their own customer load and not tied to other feeders	Feeders are in their normal configuration and not tied to other feeders
Effect of capacitor banks and line regulators on feeders ignored	Capacitor banks disconnected and line regulators allowed to adjust
Transformer losses approximate and generalized, not based on actual transformer impedances	Transformer losses included in WindMil calculation based on transformer impedances by nameplate kVA
Transformer loss evaluation assumes 1.025pu voltage on primary side	Voltage on transformer primary side determined by WindMil or set to 1.00pu
All secondary lines are modeled as #2 AL Triplex conductor	All conductor assumptions in WindMil model are based on GIS data
Feeder voltage at substation source is 5 percent above nominal (1.05pu)	Feeder voltage at substation source is nominal (1.00pu)
Distribution feeders that do not serve any customers are modeled as sub-transmission lines and included in total percent loss of the distribution system	Losses calculated directly for parent feeders by voltage class consistent with other feeders included in the study
Feeder power factor is equal to unity	Feeder power factor based on historical load data from head of feeder

Appendix B: Feeder Loss Calculations

Table 8 below provides a comparison of feeders for which the loss percentages changed significantly after review and refinement of model data, as discussed in Section 4.4 of the report. The table on the following page provides detailed feeder loss calculation data for all feeders included in the study.

Feeder	Voltage Class	Original Loss Percentage	Refined Loss Percentage
FOR-263	14 kV	10.94 %	3.72 %
FOR-262	14 kV	14.08 %	3.61 %
SND-218	14 kV	11.42 %	5.29 %
BRW-2	12 kV	13.59 %	13.07 %
FLN-1	12 kV	20.20 %	4.53 %
FLN-2	12 kV	10.78 %	8.00 %
SWB-1	4 kV	20.15 %	16.40 %
KYL-1	4 kV	10.79 %	8.75 %
STZ-1	4 kV	11.64 %	9.55 %

Table 9: Model Validation & Refinement of Individual Feeder Loss Percentages

Feeder	Voltage Class (kV)	Area	Feeder Peak Date	Peak Loading @ Source (MW)	Peak Losses (kW)	Peak Loss Percentage	Avg Loading @ Source (MW)	Load Factor	Loss Factor	Average Losses (kW)	Energy Losses (MWh)	Annual Energy (MWh)	Energy Loss Percentage
31 Line	46	N	2/13/20 11:00 PM	4.60	5.00	**0.11%**	2.55	55.51%	38.23%	1.91	16.79	22,431.40	**0.07%**
32 Line	46	N	1/17/20 12:00 AM	8.40	136.00	**1.62%**	4.37	52.06%	34.59%	47.04	413.22	38,413.00	**1.08%**
33 Line	46	N	1/17/20 12:00 AM	12.50	429.00	**3.43%**	5.32	42.59%	25.48%	109.30	960.13	46,769.30	**2.05%**
BCR-23	46	C	2/20/20 7:00 AM	1.80	9.00	**0.50%**	0.98	54.55%	37.19%	3.35	29.40	8,624.90	**0.34%**
BAX-534	34	W	7/3/20 5:00 PM	6.15	155.00	**2.52%**	2.71	44.01%	26.76%	41.48	364.36	23,767.18	**1.53%**
RVT-532	34	W	12/1/20 8:00 AM	2.08	44.83	**2.16%**	0.52	25.08%	11.93%	5.35	46.97	4,572.72	**1.03%**
LSPI-208	34	C	7/6/20 3:00 PM	8.10	50.00	**0.62%**	4.81	59.36%	42.48%	21.24	186.56	42,237.20	**0.44%**
SLA-203	34	C	7/6/20 4:00 PM	13.60	362.11	**2.66%**	9.47	69.66%	54.86%	198.66	1,745.04	83,214.10	**2.10%**
LPR-501	34	W	7/31/20 3:00 PM	6.70	57.00	**0.85%**	4.22	62.97%	46.65%	26.59	233.57	37,087.46	**0.63%**
LPR-527	34	W	7/7/20 6:00 PM	7.48	10.80	**0.14%**	4.70	62.79%	46.44%	5.02	44.05	41,242.15	**0.11%**
LPR-535	34	W	7/7/20 1:00 PM	11.84	244.00	**2.06%**	7.44	62.89%	46.55%	113.59	997.73	65,388.85	**1.53%**
EGV-517	34	W	1/8/20 5:00 PM	7.90	102.00	**1.29%**	4.52	57.21%	40.08%	40.88	359.08	39,701.90	**0.90%**
PPL-514	34	W	2/13/20 11:00 PM	8.40	167.97	**2.00%**	5.09	60.65%	43.94%	73.81	648.34	44,749.80	**1.45%**
AUR-313	23	N	7/3/20 2:00 PM	4.26	79.02	**1.85%**	1.65	38.59%	22.00%	17.38	152.70	14,450.31	**1.06%**
HIB-308	23	N	6/11/20 12:00 PM	4.55	128.00	**2.82%**	3.34	73.48%	59.83%	76.59	672.74	29,356.44	**2.29%**
HIB-310	23	N	1/8/20 6:00 PM	6.69	462.00	**6.91%**	4.02	60.03%	43.24%	199.75	1,754.63	35,270.81	**4.97%**
HIB-315	23	N	12/30/20 7:00 PM	1.19	17.00	**1.43%**	0.69	57.93%	40.87%	6.95	61.03	6,275.38	**0.97%**
MTU-330	23	N	12/14/20 10:00 AM	2.80	53.00	**1.89%**	0.87	31.15%	16.14%	8.55	75.12	7,661.00	**0.98%**
HIB-312	23	N	12/22/20 9:00 AM	7.38	47.00	**0.64%**	2.41	32.70%	17.30%	8.13	71.41	21,188.07	**0.34%**
VRG-302	23	N	1/16/20 7:00 PM	4.77	83.00	**1.74%**	2.90	60.90%	44.23%	36.71	322.47	25,500.11	**1.26%**
GRY-200	14	C	7/18/20 5:00 PM	3.14	150.80	**4.81%**	1.78	56.61%	39.41%	59.43	522.07	15,592.96	**3.35%**
GRY-201	14	C	7/26/20 4:00 PM	3.25	153.00	**4.71%**	2.00	61.41%	44.82%	68.58	602.42	17,548.99	**3.43%**
FRR-275	14	C	2/14/20 8:00 AM	3.10	272.30	**8.78%**	1.43	46.20%	28.80%	78.42	688.81	12,579.50	**5.48%**
RGV-253	14	C	2/14/20 7:00 AM	4.50	336.60	**7.48%**	2.39	53.03%	35.60%	119.82	1,052.54	20,963.30	**5.02%**
CLQ-406	14	C	7/2/20 3:00 PM	10.32	509.00	**4.93%**	5.97	57.90%	40.83%	207.83	1,825.60	52,482.55	**3.48%**
CLQ-409	14	C	7/2/20 4:00 PM	7.32	394.78	**5.37%**	4.38	59.77%	42.94%	169.53	1,489.12	38,433.55	**3.87%**
CLQ-410	14	C	2/19/20 9:00 AM	4.13	196.00	**4.75%**	2.48	60.11%	43.33%	84.92	745.95	21,780.82	**3.42%**
WRN-411	14	C	12/24/20 9:00 AM	3.67	290.59	**7.92%**	1.91	52.15%	34.68%	100.78	885.25	16,796.74	**5.27%**
COL-240	14	C	12/24/20 5:00 PM	7.53	495.90	**6.58%**	4.17	55.31%	38.01%	188.48	1,655.65	36,604.66	**4.52%**
COL-241	14	C	12/24/20 6:00 PM	4.16	230.90	**5.55%**	2.17	52.21%	34.74%	80.22	704.62	19,091.83	**3.69%**
COL-242	14	C	1/16/20 6:00 PM	6.27	358.60	**5.71%**	3.83	60.97%	44.32%	158.92	1,395.93	33,601.07	**4.15%**
COL-244	14	C	12/24/20 5:00 PM	4.78	255.80	**5.35%**	2.76	57.73%	40.64%	103.97	913.26	24,231.71	**3.77%**
COL-245	14	C	2/14/20 7:00 AM	1.67	203.20	**12.15%**	1.19	71.36%	57.05%	115.92	1,018.27	10,478.11	**9.72%**
TFW-243	14	C	7/6/20 4:00 PM	3.20	157.30	**4.92%**	1.47	45.79%	28.41%	44.70	392.61	12,871.10	**3.05%**
FOR-263	14	C	6/26/20 1:00 PM	2.90	107.80	**3.72%**	1.64	56.59%	39.40%	42.47	373.06	14,416.40	**2.59%**
FOR-262	14	C	2/13/20 11:00 AM	2.60	93.80	**3.61%**	1.14	43.69%	26.47%	24.83	218.07	9,977.70	**2.19%**
SND-217	14	C	7/2/20 11:00 AM	3.70	143.70	**3.88%**	1.97	53.32%	35.89%	51.58	453.07	17,328.40	**2.61%**
SND-218	14	C	12/24/20 11:00 AM	2.40	127.00	**5.29%**	1.07	44.43%	27.15%	34.48	302.86	9,366.90	**3.23%**
NIN-248	14	C	1/16/20 6:00 PM	3.80	235.00	**6.18%**	2.17	57.03%	39.88%	93.71	823.12	19,035.90	**4.32%**
NIN-246	14	C	7/9/20 2:00 PM	2.60	149.10	**5.73%**	1.63	62.75%	46.39%	69.16	607.53	14,330.90	**4.24%**
INF-1	12	N	7/3/20 6:00 PM	2.26	306.80	**13.56%**	1.29	57.10%	39.95%	122.57	1,076.64	11,345.69	**9.49%**
INF-2	12	N	7/2/20 5:00 PM	3.54	193.80	**5.48%**	2.11	59.59%	42.74%	82.82	727.51	18,527.68	**3.93%**
INF-3	12	N	7/3/20 4:00 PM	4.51	401.90	**8.91%**	2.64	58.48%	41.48%	166.70	1,464.33	23,177.16	**6.32%**
INF-4	12	N	7/1/20 4:00 PM	2.85	148.90	**5.23%**	1.59	55.68%	38.41%	57.19	502.32	13,929.73	**3.61%**

Feeder	Voltage Class (kV)	Area	Feeder Peak Date	Peak Loading @ Source (MW)	Peak Losses (kW)	Peak Loss Percentage	Avg Loading @ Source (MW)	Load Factor	Loss Factor	Average Losses (kW)	Energy Losses (MWh)	Annual Energy (MWh)	Energy Loss Percentage
WRR-6321	12	C	[redacted]	0.68	79.60	**11.71%**	[redacted]	52.15%	34.68%	27.61	242.49	2,924.13	**8.29%**
PIL-1	12	W	[redacted]	0.30	46.50	**15.50%**	[redacted]	44.01%	26.76%	12.44	109.31	2,078.75	**5.26%**
LNL-1	12	W	[redacted]	0.20	19.30	**9.65%**	[redacted]	44.01%	26.76%	5.16	45.37	1,385.83	**3.27%**
PNB-1/PNB-2	12	W	[redacted]	2.93	240.50	**8.21%**	[redacted]	44.01%	26.76%	64.36	565.34	20,302.42	**2.78%**
CQB-6301	12	C	[redacted]	1.20	108.80	**9.07%**	[redacted]	59.77%	42.94%	46.72	410.40	6,300.66	**6.51%**
RVD-1	12	W	[redacted]	0.47	35.10	**7.47%**	[redacted]	25.08%	11.93%	4.19	36.78	1,033.32	**3.56%**
LGP-1	12	W	[redacted]	0.81	93.80	**11.58%**	[redacted]	62.97%	46.65%	43.76	384.37	4,483.65	**8.57%**
GGR-1	12	W	[redacted]	2.69	152.00	**5.65%**	[redacted]	62.79%	46.44%	70.58	619.99	14,831.00	**4.18%**
BBR-1	12	W	[redacted]	1.20	31.50	**2.63%**	[redacted]	62.89%	46.55%	14.66	128.81	6,650.00	**1.94%**
HPS-1	12	W	[redacted]	0.51	22.50	**4.41%**	[redacted]	62.89%	46.55%	10.47	92.00	2,826.00	**3.26%**
LCH-1	12	W	[redacted]	0.65	60.20	**9.26%**	[redacted]	62.89%	46.55%	28.02	246.16	3,589.00	**6.86%**
LPN-1	12	W	[redacted]	0.05	3.90	**7.80%**	[redacted]	62.89%	46.55%	1.82	15.95	276.00	**5.78%**
CLR-1	12	W	[redacted]	2.20	160.00	**7.27%**	[redacted]	57.21%	40.08%	64.12	563.26	11,056.00	**5.09%**
CLR-2	12	W	[redacted]	0.20	16.50	**8.25%**	[redacted]	57.21%	40.08%	6.61	58.09	1,005.00	**5.78%**
BRW-1	12	W	[redacted]	3.03	236.00	**7.79%**	[redacted]	57.21%	40.08%	94.58	830.80	15,227.00	**5.46%**
BRW-2	12	W	[redacted]	3.45	451.00	**13.07%**	[redacted]	57.21%	40.08%	180.75	1,587.68	17,338.00	**9.16%**
FLN-1	12	W	[redacted]	0.15	6.80	**4.53%**	[redacted]	60.65%	43.94%	2.99	26.25	799.00	**3.29%**
FLN-2	12	W	[redacted]	0.65	52.00	**8.00%**	[redacted]	60.65%	43.94%	22.85	200.71	3,462.00	**5.80%**
LLK-1	12	W	[redacted]	0.72	67.80	**9.42%**	[redacted]	60.65%	43.94%	29.79	261.70	3,835.00	**6.82%**
SWN-1	12	W	[redacted]	2.27	133.00	**5.86%**	[redacted]	60.65%	43.94%	58.44	513.36	12,093.00	**4.25%**
BAL	12	N	[redacted]	1.41	23.80	**1.69%**	[redacted]	60.03%	43.24%	10.29	90.39	7,433.80	**1.22%**
KER-6501	12	C	[redacted]	0.80	87.70	**10.97%**	[redacted]	54.55%	37.19%	32.62	286.53	3,622.46	**7.91%**
ASK-6521	12	C	[redacted]	1.10	65.10	**5.92%**	[redacted]	54.55%	37.19%	24.21	212.69	5,002.44	**4.25%**
HYN-1	4	N	[redacted]	0.56	25.30	**4.52%**	[redacted]	38.59%	22.00%	5.57	48.89	1,899.57	**2.57%**
HYN-2	4	N	[redacted]	1.89	146.30	**7.74%**	[redacted]	38.59%	22.00%	32.19	282.72	6,411.05	**4.41%**
LPD-2	4	W	[redacted]	0.58	24.20	**4.17%**	[redacted]	62.79%	46.44%	11.24	98.71	3,197.90	**3.09%**
SWB-1	4	N	[redacted]	0.20	32.80	**16.40%**	[redacted]	73.48%	59.84%	19.63	172.41	1,290.40	**13.36%**
CHL-1	4	N	[redacted]	2.30	184.00	**8.00%**	[redacted]	60.03%	43.24%	79.56	698.81	12,126.00	**5.76%**
CHL-2	4	N	[redacted]	1.15	80.70	**7.02%**	[redacted]	60.03%	43.24%	34.89	306.49	6,063.00	**5.06%**
CHL-3	4	N	[redacted]	1.87	146.40	**7.83%**	[redacted]	60.03%	43.24%	63.30	556.01	9,859.00	**5.64%**
KYL-1	4	N	[redacted]	0.56	49.00	**8.75%**	[redacted]	57.93%	40.87%	20.03	175.91	2,952.00	**5.96%**
SVE-1	4	N	[redacted]	0.09	12.00	**13.33%**	[redacted]	31.15%	16.14%	1.94	17.01	245.20	**6.94%**
SVW-1	4	N	[redacted]	0.26	24.50	**9.42%**	[redacted]	31.15%	16.14%	3.95	34.73	711.40	**4.88%**
STZ-1	4	N	[redacted]	0.22	21.00	**9.55%**	[redacted]	31.15%	16.14%	3.39	29.77	601.90	**4.95%**

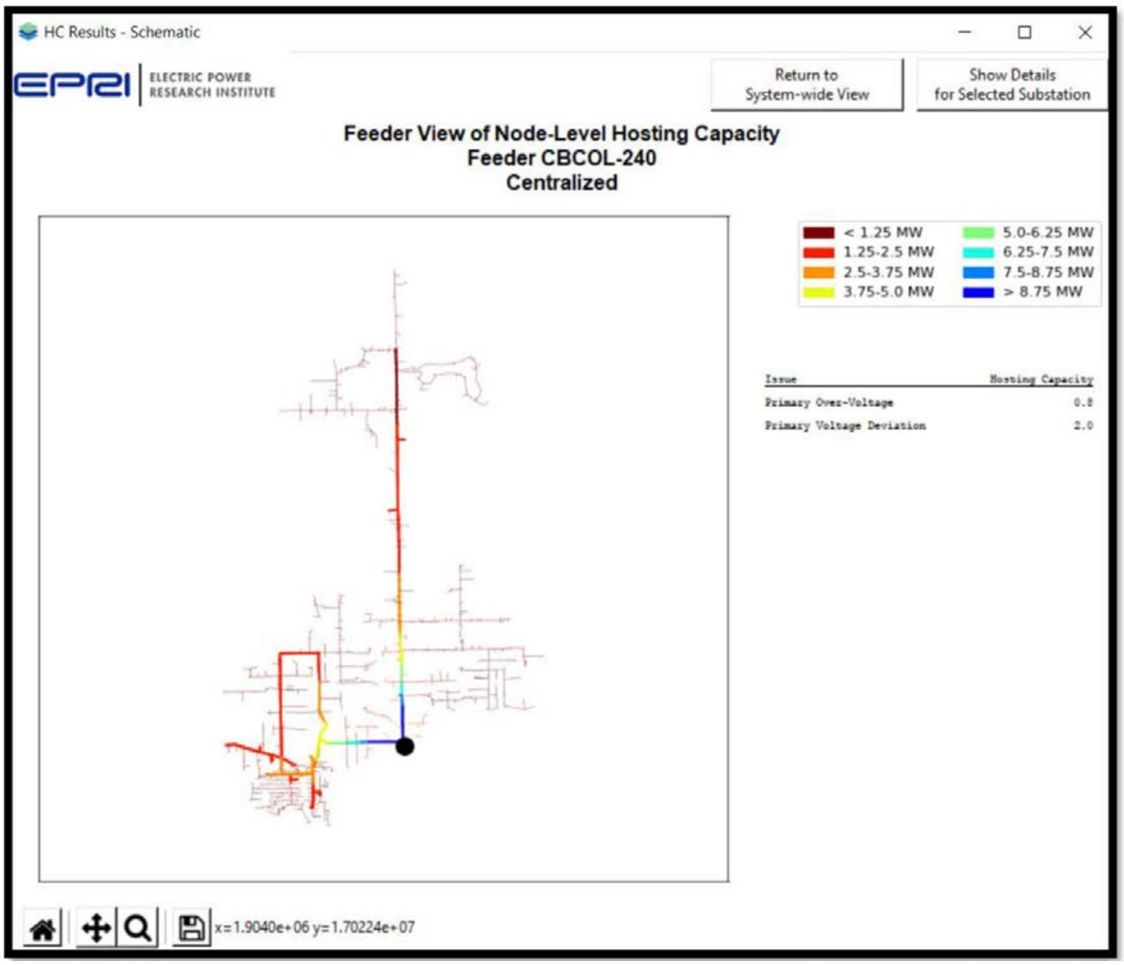
Averages by Voltage Class	Peak Loss %	Energy Loss %
4	8.79%	5.69%
12	8.11%	5.28%
14	5.87%	4.07%
23	2.47%	1.70%
34	1.59%	1.08%
46	1.42%	0.89%

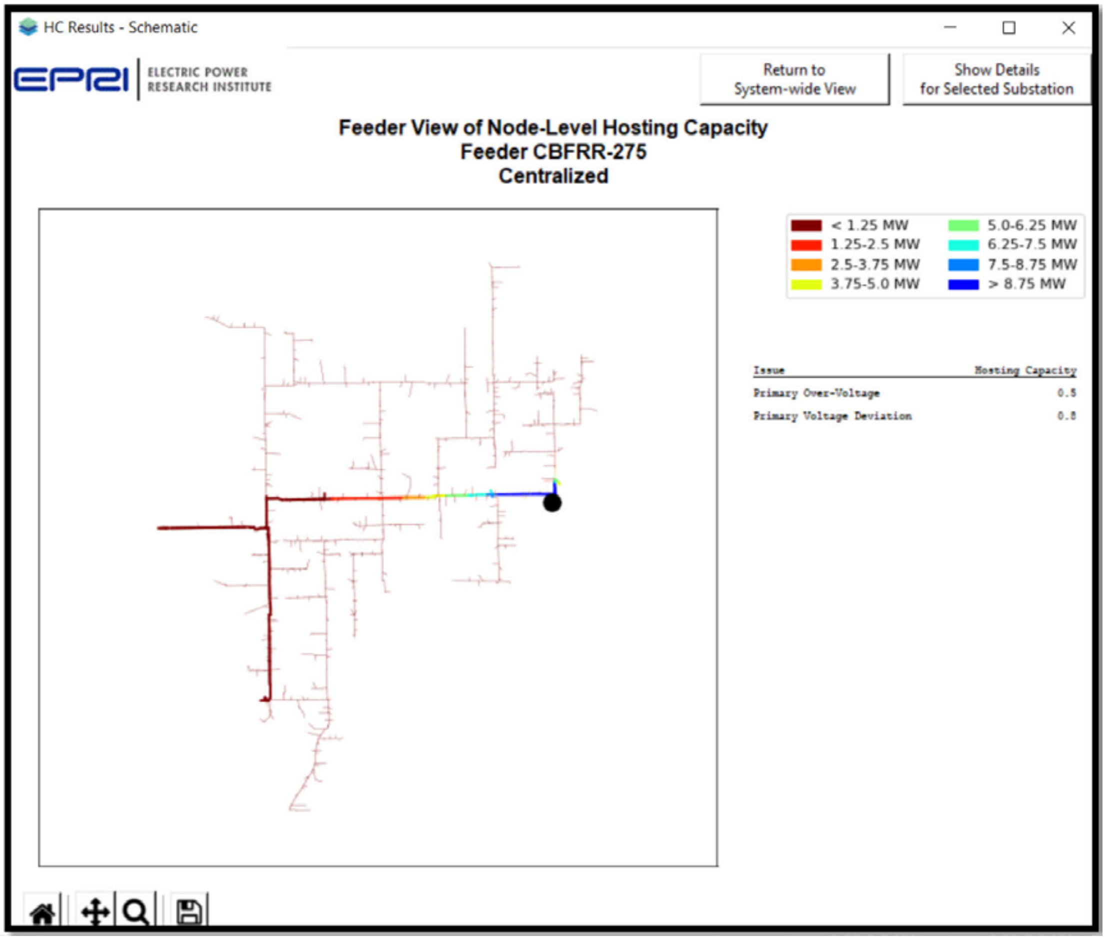
Historical Peak and Daytime Minimum Load Data (2019)
Historical Peak and Daytime Minimum Load Data (2020)

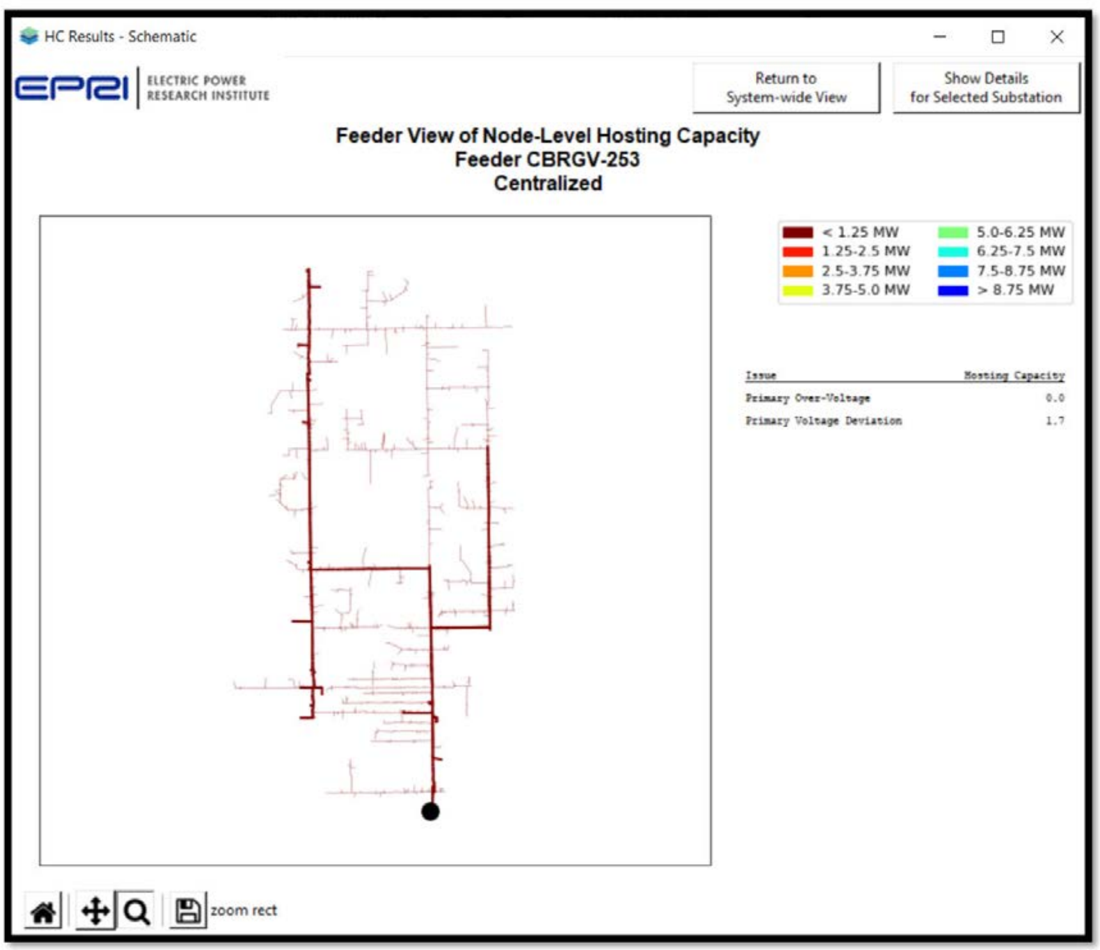
Both E-filed as Excel Spreadsheets

Example Hosting Capacity Heat Maps

The hosting capacity heat maps below were produced, with assistance from EPRI, using the EPRI DRIVE tool applied to existing Minnesota Power WindMil models for three feeders in the Duluth area. These heat maps provide an example of the type of data that may be produced by the DRIVE tool. Because only two criteria (Primary Over-Voltage and Primary Voltage Deviation) were applied in the development of the heat maps, they should be considered incomplete. Further evaluation of the DRIVE tool and results is necessary to determine the most appropriate set of criteria to be applied for hosting capacity studies of Minnesota Power distribution feeders.




HC Results - Schematic
ELECTRIC POWER RESEARCH INSTITUTE
Return to System-wide View
Show Details for Selected Substation
Feeder View of Node-Level Hosting Capacity
Feeder CBFRR-275
Centralized
< 1.25 MW
1.25-2.5 MW
2.5-3.75 MW
3.75-5.0 MW
5.0-6.25 MW
6.25-7.5 MW
7.5-8.75 MW
> 8.75 MW
Issue
Hosting Capacity
Primary Over-Voltage
0.5
Primary Voltage Deviation
0.8


HC Results - Schematic
ELECTRIC POWER RESEARCH INSTITUTE
Return to System-wide View
Show Details for Selected Substation
Feeder View of Node-Level Hosting Capacity
Feeder CBRGV-253
Centralized
< 1.25 MW
1.25-2.5 MW
2.5-3.75 MW
3.75-5.0 MW
5.0-6.25 MW
6.25-7.5 MW
7.5-8.75 MW
> 8.75 MW
Issue
Hosting Capacity
Primary Over-Voltage
0.0
Primary Voltage Deviation
1.7
zoom rect

PUC IDP Requirement - Order Point 2 (05/27/2020 Order in Docket No. E015/M-19-684)				
Planning Objective	**Analysis of how the information in the IDP relates to each Planning Objective**	**Location**	**Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives**	**Suggestions as to any refinements of the IDP filing requirements that would enhance Minnesota Power's ability to meet the Planning Objectives**
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	Minnesota Power's 2021 IDP provides a holistic description of how the Company is meeting this planning objective, and it this objective is covered in some level in each section. Specifically, projects identified in the 5 year investment plan in section IID and current projects outlined in section IIE are aimed to address this planning objective. Cyber security is covered in section IIH. Minnesota Power has undertaken a number of efforts to ensure fair and reasonable costs. While this is a focus throughout the IDP, the Company's residential rate design, low-income solar program and reconnect pilot program are specific examples of efforts to provide customers with more control over their energy bills, increase accessability of renewable energy and eliminate reconnection fees for customers. These efforts are described in Section III.	Section I, I, III, IV	In mid-2021, Minnesota Power initiated a consultant-led Distribution Non-Wire Alternatives Study to gain experience with the evaluation, development, and justification of non-wire solutions. The study is focused on specific opportunities on Minnesota Power's system where enhanced backup capability, feeder automation, or dynamic voltage control are or could become desirable. The consultant is tasked with developing a non-wire solution for each opportunity, assisting Minnesota Power in developing a framework for determining where non-wire solutions provide sufficient value to recommend moving forward, and producing sufficient technical scoping information for Minnesota Power to separately develop and procure any or all of the non-wire solutions developed for the study. This study effort is expected to take the entirety of the rest of 2021, and possibly into 2022, meaning earliest implementation for any resulting non-wire solution projects would most likely be in 2023. Minnesota Power can provide an update on the current status of the Non-Wire Alternatives Study during the comment period for this docket.	The Company has no suggestions at this time.
Enable greater customer engagement, empowerment, and options for energy services	Minnesota Power's *Energy* ***Forward*** strategy outlines a vision for a sustainable future for the customer, community, climate and company. The Company's 2021 IDP considers each of these important perspectives. Minnesota Power is planning for the future of an advanced grid while also enhancing the customer experience. The Company's 10-year long-term plan focuses on continued investment in infrastructure with accelerated investments in the near-term in systems and data to optimize the 21st Century power grid. Investments in data and applications will provide a greatly enhanced customer experience while enabling key operational benefits for reliability and safety.	Section III	Minnesota Power contends that sustainability – in all of its forms – plays a critical role in ensuring security, comfort, and quality of life for customers. The Company is committed to strengthening its diversity, equity, and inclusion ("DE&I") efforts which are captured in this IDP. Specific funding for DE&I efforts will be included in the rate case Minnesota Power intends to file in the fall of 2021. Throughout 2021, Company leaders developed a framework to strengthen efforts and identified three key areas where the Company will take action: workforce, supply chain, and Minnesota Power as a community citizen. Additionally, Minnesota Power convened the longest and robust stakeholder process it had ever done to facilitate the development of its residential rate redesign to be the first utility to propose a future default Time of Use rate for customers.	The Company has no suggestions at this time.
Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies	As Minnesota Power advances towards its carbon-free vision, the Company will focus on right time/right fit investments, operational efficiencies, and reliability/resiliency upgrades to ensure a modern grid can continue to support the Company's EnergyForward strategy. The systems implementation timeline communicated through this Plan seamlessly integrates current customer systems, asset management, and operational systems under one real-time Utility Network model. This secure end-to-end system model will integrate all of Minnesota Power's generation sources, transmission infrastructure, and distributed assets and resources. This model will reside within a flexible, adaptable, and upgradable platform which will aid the Company to grow and respond to utility system dynamics and meet public policy goals. It will allow for a streamlined data gathering process to provide meaningful and proper data sets for stakeholders and the Company which will be utilized to advance a customer-centric, modern grid.	Section II, III, IV	Listed in sections II and III are examples of new projects or programs Minnesota Power has proposed or implemented to improve upon the fulfillment of this planning objective. A few examples include, but are not limited to, non-wires alternative work and residential rate redesign. As mentioned in response to the first planning objective, in mid-2021 Minnesota Power initiated a consultant-led distribution non-wire alternatives study to gain experience with the evaluation, development and justification of non-wires alternatives. Additionally, since the last IDP the Commission has approved Minnesota Power's residential rate design proposal to move towards a default time of use rate for residential customers which will remove barriers to electrification and incentivize the efficient use of the system while also giving customers more control over their energy bills.	The Company has no suggestions at this time.

PUC IDP Requirement - Order Point 2				
Planning Objective	**Analysis of how the information in the IDP relates to each Planning Objective**	**Location**	**Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives**	**Suggestions as to any refinements of the IDP filing requirements that would enhance Minnesota Power's ability to meet the Planning Objectives**
Ensure optimized utilization of electricity grid assets and resources to minimize total system costs	Information on Minnesota Power's financial planning is included in Section IV, and the Company's 5 year investment plan is included in Section II. Throughout Minnesota Power's planning it strives to ensure safety and reliability at an affordable cost to customers.	Section II, III, IV	Historical spend and planning has positioned the Company for a seamless transition to an innovative future to meet customers' needs and expectations. The foundational investments are built upon the Company's Core Values and distribution strategy of technology, innovation, and continuous learning. The Company has demonstrated these values by focusing on right time, right fit investments and by thoughtfully leveraging internal and external resources in a cost conscious manner to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid.	The Company has no suggestions at this time.
Provide the Commission with the information necessary to understand Minnesota Power'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	The Company has outlined that its values include identifying the right time, right fit investments for the distribution system to manage costs for customers and ensure value is provided. Minnesota Power has provided information on its short and long term distribution plans within this IDP. Information on the Company's 5 year investment plan is included in Section II, information on financial planning for the future is included in Section IV. Additionally, through many specific projects included in this IDP, the Company identifes how it is controlling costs. For example, Strategic Undergrounding is identified as an effort to reduce O&M vegetation management costs, as well as trouble costs, as it improves reliability.	Section II, IV	Minnesota Power will continue developing cost-benefit analysis for a number of items ahead of the next IDP. For example, as noted in the IDP, the Company will be evaluating a cost-benefit analysis framework in the Distribution Non-Wire Alternatives Study to help assess the benefits and potential payback period of any non-wires alternative project. Minnesota Power also notes that a consultant may be utilized to assist in the future cost benefit analysis of emerging technologies like grid-scale battery storage.	The Company has no suggestions at this time.

STATE OF MINNESOTA)
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COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

SUSAN ROMANS of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **25th** day of **October, 2021**, she served Minnesota Power's Biennially Integrated Distribution Plan (IDP) in **Docket No. E015/M-21-390** on the Minnesota Public Utilities Commission and the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served.

Susan Romans

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Susan Romans

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-390_M-21-390
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-390_M-21-390
Melinda	Granley	mgranley@duluthmn.gov		411 West First St Duluth, MN 55802	Electronic Service	No	OFF_SL_21-390_M-21-390
Alexander	Jackson	ajackson@DuluthMN.gov	Minnesota Power	1532 W Michigan St Duluth, MN 55806	Electronic Service	No	OFF_SL_21-390_M-21-390
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	Yes	OFF_SL_21-390_M-21-390
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-390_M-21-390
Anne	Rittgers	arittgers@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_21-390_M-21-390
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-390_M-21-390